Wide Area Monitoring and Situational Awareness

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13.1 Introduction

13.1.1 Drivers and Objectives for Wide Area Monitoring

Wide Area Measurement Systems (WAMS) are making their way into electric utility systems driven by requirements for soft solutions to improving system economics, and system reliability. Time-synchronized phasor data from WAMS sampled at sufficiently high volume represents the true state of the power system and offer excellent solution to the new operational challenges of modern power systems. In a typical wide area measurements system, phasor measurement units (PMUs) are dispersed in wide geographical region to sample voltages and currents for delivery to several monitoring centers where software applications process the phasors for monitoring, protecting, and controlling the power system (Figure 14- 1).

- ***Improving System Economics***: Of late environmental constraints have put a hold in the construction of new transmission lines resulting in transmission bottlenecks as existing facilities approach their loading limits. Bottlenecks impose dispatch limits on generating units and often result in uneconomic operation of the power system. Such limits are currently estimated a priori from the models of the power system at hand. The problem is that inaccurate models can overly estimate these limits or that the models are not updated frequent enough to make the limits representative of the current conditions. Time-synchronized phasor data from WAMS are useful for calculating transmission limits in real time. For example, WAMS can accurately estimate conductor temperatures and transmission line sags, parameters that reflect the state of conductor capacity. In a wider scale, synchrophasor voltage angles have been mixed with existing asynchronous measurements to improve the estimation of the state of the system. Good state estimates increases the accuracy and lessens the uncertainties of line loadings and derivatives of power system models such as stability margins. With less model uncertainties capacity margins reserved by operators for contingencies can be decreased thereby releasing reserved transmission capacity to the least cost generating units. Other uneconomic dispatch strategies such as underutilizing generating capacity to guard against oscillatory instabilities can be abandoned when wide area control systems are installed to mitigate such instabilities.

- ***Improving System Reliability***: Driven by load growth and delays in transmission reinforcement, modern power systems are being operated closer to their stability limits and have increased the risk of angle and voltage instability and thermal overloads. Additionally, the intermittency and unpredictability of unconventional generating sources from renewable energy carry new operational challenges. Maintaining system reliability under these conditions necessarily require additional closed loop controls and improved operator tools for managing the operations of the whole network. With improved tools and visualization, operators can make more responsive and accurate dispatch or switching decisions to improve system reliability. WAMS can help operators increase their situational awareness by increasing observability of their control area and neighboring systems. For example, evolving situations from outside the control area can be viewed promptly in combination with geographical information systems. With WAMS oscillatory disturbances can be viewed in the operator workplace. Power systems typically leave traces of evidence in voltages and currents that are helpful for identifying nature of disturbances. Wide area time-synchronized frequency information can help operators locate remote generator outages that could potentially impact system integrity. In some reference installations WAMS have been deployed to monitor risk of voltage instabilities of transmission corridors, such dedicated systems are more accurate and enhance operators' awareness of nearness to voltage collapse.

- ***Meeting Smart Grid Challenges**:* Smart grids initiatives will impose new reliability and economic requirements that will impact how transmission systems will be monitored, protected and controlled in the future. Large renewable energy will penetrate power systems from all directions; grid level renewable parks such as wind and solar and distribution-level distributed generation will introduce higher intermittency in magnitude and direction of power. The intermittency will impose challenges in maintaining power quality and more so stability of frequency and voltage where traditional local controllers might not work effectively. New control strategies based on remote measurements from multiple locations and acting on a range of controllers are more efficient in controlling such disturbances. Wide area control systems (WACS) works under this principle. In coordination with controllable devices such as Flexible AC Transmission Systems, storage or generator excitation, WACS are capable of controlling multiplicity of power flows and voltages in the network to mitigate power oscillations or congestion problems. Wide area measurement systems can be extended "deep" into distribution network to allow operators to monitor evolving situations from the distribution system such as caused by instability of distributed generators or voltage collapse that may propagate into the transmission network.

13.1.2 Need for "Situational Awareness"

The power grid operating conditions are continually changing - every second, every minute and every hour of the day. This is because changes in electricity demand dictate immediate, instantaneous changes in electricity production; consequentially, voltages, currents and power flows are dynamically changing, at all times, across the vast electricity delivery network called the power grid.

The challenge is to ensure that these changing power system operating conditions always stay within safe limits for the present instance in time, as well as for a set of postulated, potential contingencies that might occur; if these safe limits are violated, equipment may be tripped by protection systems which would further compromise the ability to deliver power across the grid. Maintaining the integrity of the grid means to ensure that operating conditions are always safe, while successfully supplying generation to meet the ever-changing customer demand.

Grid conditions need to be monitored in a timely periodic manner in order to immediately detect any adverse conditions, as soon as they arise, so that corrective actions could be implemented to mitigate potentially harmful conditions that could lead to a wide-spread grid collapse. Since there is a tremendous volume of constantly changing conditions across the grid, the challenge is to sift through this data to identify conditions that are potential imminent problems that need operator attention. The challenge is to convert vast amounts of data into useful information.

As early as in 1965, visualization of the grid was stated to be a high priority to ensure the integrity of grid operations. In the aftermath of the 1965 blackout of the Northeast United States and Canada, the findings from the blackout report included the following: *"control centers should be equipped with display and recording equipment which provide operators with as clear a picture of system conditions as possible".* Since then many more blackouts have occurred, small and large, around the world, and in almost all cases, improvements in visibility of grid conditions were identified as one of the primary recommendations.

On August 14th, 2003, the largest blackout in the history of the North American power grid occurred. Subsequently, numerous experts from across the industry were brought together to create a blackout investigation team. A primary objective of this team was to perform in-depth post-event analyses to identify the root causes of the event; and more importantly to make recommendations on what could be done to prevent future occurrences of such events. The report [1], identified four root causes: inadequate system understanding, ***inadequate situational awareness***, inadequate tree trimming, and inadequate reliability coordinator diagnostic support. This report gave a sudden new prominence to the term 'situation awareness' or 'situational awareness'. Interviews that were conducted subsequent to the August 14, 2003 blackout identified the following gaps in operator situation awareness:

- Inadequate information sharing and communication between neighboring system operators
- Information is available and not always used. Displays and visualization tools need to increase the availability and utility of real-time information
- Information about grid operations decisions need to be shared along with real-time information
- Need to re-define what 'Normal Operations" means

13.1.3 What is Situation Awareness?

From Contemporary Psychology: *"Situation Awareness (SA) is, simply put, understanding the situation in which one is operating."* Situation Awareness is more comprehensively defined as *"...the perception of the elements in the environment within a volume of time and space, the comprehension of their meaning, and the projection of their status in the near future*" [3]. It transcends the more traditional human factors/visualization studies centered on transactions between the operator and the computer, and needs to focus on factors and interaction/tool requirements that address issues of sense-making and information sharing.

Situation awareness is based on getting real-time information from the system being monitored. These inputs are typically asynchronous and from diverse, different parts of the system. The objective of situation awareness is to assimilate the real-time data, to assess the vulnerability of the current state, to make short-term projections based on personal experience or analytical tools, and to identify and issue corrective actions, if necessary. Hence, situation awareness consists of the following 3 stages: *Perception*, *Comprehension and Projection*.

These first 3 Stages form the critical input to - but is separate from – implementation stages (if necessary) which include *Decision-making and Action*.

13.1.3.1 Perception

Stage 1 involves perceiving the status, attributes, and dynamics of relevant elements in the environment. Within the power grid operations context, this equates to the operator being aware of the current state of the power grid – power flows across critical flowgates, congested paths, acceptable voltage profiles, adequate reactive reserves, available generation, frequency trends, line and equipment status, as well as weather patterns, winds, and lightning information. It is shown that 76% of situational awareness errors in pilots were related to not perceiving the needed information [4].

13.1.3.2 Comprehension

Comprehension of the situation is based on a synthesis of disjointed Stage 1 elements. Stage 2 goes beyond simply being aware of the elements that are present, by putting them together to form patterns with other elements, and developing a holistic picture of the environment including a comprehension of the significance of information and events.

13.1.3.3 Projection

It is the ability to utilize the status and dynamics of the elements and a comprehension of the situation (both Stage 1 and Stage 2), to project future actions of the elements in the environment.

13.1.3.4 Decision-Making

This stage involves using all the knowledge gained in the first 3 Stages to identify the best recourse to mitigate or eliminate the perceived problem. Here analytical tools and on-the-job experience is used to come up with a suitable plan of action.

13.1.3.5 Action

This is the final stage of implementing the decision that has been made. Here operator control displays are used to precisely locate the means by which the action can be implemented and then to actually issue a command action to the system. Once the action is issued the operator needs to verify successful implementation of the action and to ensure that the system is subsequently stabilized and does not need any additional analysis or control.

13.1.4 Situation Awareness for Power Grid Operations

For most of the time, the grid is in the Normal or Alert state and the electricity supply chain functions quite well with built-in automatic controls (e.g. AGC, protection schemes, etc), and does not require operator intervention. It is only when a sudden disturbance occurs that an operator needs to be involved. When this happens, the typical operator's thought process sequence is:

- Just received a new problem alert!
    - Is it a valid alert or a false alarm?
        - Has any limit been violated?
            - If so, how serious is this violation; can it be ignored?
- Where is the problem located?
    - What is the likely root cause?
- Is there any corrective or mitigative action that could be taken now?
    - What is the action?
        - Must it be implemented now; or can I just wait and monitor the situation?
- Has the problem been resolved?
    - Is there any follow-up action I need to take?

13.1.5 Grid Operator Visualization Advancements

As the saying goes, "*a picture is worth a thousand words*". More importantly, the ***correct picture is worth a million words!*** What this means is that providing the operator with a concise pictorial depiction of voluminous grid data is meaningful; whereas, providing a pictorial depiction of voluminous grid data that *needs immediate operator attention*, is immensely more meaningful! This is the objective of an advanced, intelligent situation awareness; to provide timely information that needs prompt action, for current system conditions.

To successfully deploy Situation Awareness in power system operations, the key is to capture data from a large number of different sources and to present the data in a manner that helps the operator's' understanding of evolving events in complex, dynamic situations. Hence, while WAMS plays an important role in Situation Awareness, an advanced operator visualization framework is also required to be able to present real-time conditions in a timely, prompt manner; as well as to be able to navigate and drill-down to discover additional information, such as the specific location of the problem; and more importantly to be able to identify and implement corrective actions to mitigate the potential risk of grid operations failure.

Power system situation awareness visualization falls along the following perspectives, axes or dimensions [5]:

- ***Spatial, Geographical***: Situation awareness in power systems is highly spatial in nature. An operator may be responsible for a small region of the grid interconnection (one's own control area), or for multiple control areas, or for a large region of the interconnected grid. So, for example, a weather front moving across the region has different priorities based on the operator's regional responsibilities. Wide area grid responsibilities are where geographical information systems (GIS) and other geo-spatial visualization technologies can be effectively applied.

- ***Voltage Levels*:** Grid operations and control is typically separated into transmission (higher voltages) and distribution (lower voltages). So, for example, a distribution operator may be more concerned about maintaining a uniform voltage profile, while the transmission operator is concerned about wide area interconnection stability, market system interfaces and area transfer capacity issues.
- ***Temporal:*** Time scales for operators are typically in the seconds range. While real-time data refreshes from the traditional SCADA systems are typically received every 2 to 4 seconds from the field, the WAMS data is captured at a much higher sub-second rate. Regardless of the data source, operators have to assimilate data, make decisions and issue action in the tens of seconds or minutes time-frame. It is also important to correlate past history of grid conditions with current conditions to make an educated guess as to what future conditions are likely to be. Operator decisions are predicated on imminent future grid conditions.
- ***Functional*:** Operators within a control center are typically assigned different roles and responsibilities. At a large utility, different operators typically work on different functional aspects of grid operations. These different functions include:
    - Voltage Control
    - Transmission dispatch - switching and outages
    - Generation dispatch, AGC
    - Reliability coordination, contingency analysis – what-if scenarios
    - Oversight of remedial action or special protection schemes

- Supervisory oversight of all control center operators
- Market system operation, etc.

Situation awareness therefore consists of looking at the system from multiple different perspectives in a holistic manner. For an accurate assessment of the state of any complex, multi-dimensional system, the system needs to be ‘viewed’ at from various different angles, perspectives and potential what-if scenarios; these different views are then intelligently combined to synthesize a ‘true’ assessment. Local regions are viewed microscopically and the entire system is viewed macroscopically. This intelligent synthesis of information from various diverse perspectives will improve the operator’s capabilities and confidence to make prompt, ‘correct’ decisions. This is forms the very foundation of what is called an advanced visualization framework.

Synchrophasors and WAMS technology is a smart-grid enabling technology that not only complements existing Energy Management Systems, but also provides Situational Awareness tools with additional information to quickly assess the current grid conditions. Figure 14- 2 illustrates how a PMU-based WAMS and network model-based EMS hybrid solution within an advanced visualization framework can offer true situation awareness to grid operators.

Measurement-based WAMS techniques may be applied to quickly and accurately *assess* current grid conditions over a wide-area basis, such as monitoring phase angular separation as a measure of grid stead-state stress, detecting rapid changes in phase angle or frequency measurements - indicative of sudden weakening of power grid due line outages or generator trips, or to identity potential voltage or oscillatory stability problems.

Where the real-time network model-based dynamic security assessment such as voltage stability, small-signal stability, and transient stability assessment fit in is providing the much needed *predictive* element to help the control center operator's decision making process. Once the operators have made an assessment of the current state and its vulnerability, operators will need to rely on "What-if" analytical tools to be able to make decisions that will prevent adverse conditions if a specific contingency or disturbance were to occur and make recommendations on corrective actions. Thus the focus shifts from 'Problem Analysis' (reactive) to 'Decision-making' (preventive).

13.2 WAMS Infrastructure

13.2.1 Phasor Measurement Unit (PMU)

Phasor Measurement Units (PMUs) had their origin in a computer relay known as Symmetrical Component Distance Relay[8] for transmission line protection. This relaying algorithm calculated positive, negative, and zero sequence components of voltages and currents in order to facilitate execution of an efficient relaying algorithm. Starting in about 1982, the measurement algorithms were separated into a stand-alone function that became the basis of the modern PMU. In recent years there has been a marked increase in PMU installations on power transmission networks as part of a Wide Area Measurement System (WAMS). Applications of WAMS in power system post-mortem analysis, real-time monitoring, improved protection and control have been – and are being - developed; so that at present there are major undertakings to implement these applications on most large power systems around the world[9].

13.2.1.1 Phasors and Synchrophasors

A phasor is a complex number representing a sinusoidal function of time. A sinusoid given by $x(t) = X_m \cos(\omega t + \phi)$ has a phasor representation $\mathbf{X} \cong (X_m/\sqrt{2})\, \varepsilon^{j\phi}$. The PMUs use sampled data obtained from the sinusoid using a sampling clock with a sampling frequency ω_s , which is generally an integral multiple of the nominal signal frequency ω In order to avoid aliasing errors in phasor estimation from sampled data, it is necessary to use an anti-aliasing filter to attenuate frequencies greater than $\omega_s/2$. The sampled data version of the phasor with N samples per fundamental frequency period is given by the Discrete Fourier Transform:

$$\mathbf{X} = \frac{\sqrt{2}}{N} \sum_{n=0}^{N-1} x(n\Delta T)\varepsilon^{-j(2n\pi/N)} \tag{1}$$

where ΔT is the time interval between samples.

A *Synchrophasor* is a phasor representation which uses a common time signal (UTC) to define the instant when the measurement is made. By using a common timing signal, it becomes possible to combine phasors obtained from different locations on a common phasor diagram. The timing pulses provided by the Global Positioning System satellites are commonly used to furnish UTC reference in synchrophasor measurement systems.

13.2.1.2 A Generic Phasor Measurement Unit

A generic PMU is represented in Figure 14- 3. The GPS receiver is often an integral part of the PMU. Analog input signals are first filtered to remove extraneous interfering signals present in a power system substation before applying the anti-aliasing filters. The timing pulse provided by the GPS receiver is used to produce a phase-locked oscillator at the required sampling rate. Synchrophasors are continuously computed with each arriving data sample, and the measured phasor with the time stamp based on the UTC provided by the GPS receiver is output as a continuous data stream to various applications. In practice a hierarchical system of PMUs and Phasor Data Concentrators (PDCs) is employed to collect data over a wide area[10].

13.2.1.3 Positive Sequence Measurements

Most PMUs provide individual phase voltages and currents, as well as positive sequence quantities. The positive sequence phasor ($\mathbf{X_1}$) is calculated from phase quantities ($\mathbf{X_a}$, $\mathbf{X_b}$, $\mathbf{X_c}$) with the familiar equation: $\mathbf{X_1} = (1/3)(\mathbf{X_a} + \mathbf{X_b}\,\varepsilon^{j2\pi/3} + \mathbf{X_c}\square\varepsilon^{\square j2\pi/3})$.

13.2.1.4 Transients and Off-Nominal Frequency Signals

Most PMUs use a fixed frequency sampling clock, which is keyed to the nominal frequency of the power system. However, the power system frequency does vary constantly, and the PMU measurement system must take the prevailing frequency into account and apply required corrections to the estimated phasor.

In addition, there are transient phenomena due to faults and switching operations, harmonics etc. which must be reckoned with. As the PMU calculates synchrophasors with every sample of the input signal, there are phasor estimates which include effects of the transients. Care must be exercised when using these phasors. Most PMU applications assume quasi-steady conditions over the measurement window. Phasors with transients in the measurement windows must be discarded for such applications.

13.2.1.5 IEEE Standards

IEEE standard C37.118 and its forthcoming variants C37.118.1 and C37.118.2 dictate the requirements for synchrophasors. PMUs compliant with these standards will assure interoperability of units of different manufacture.

13.2.2 Phasor Data Concetrator (PDC)

A key attribute of PMUs is their ability to include a precise GPS timestamp with each measurement of when the measurement was taken. For applications that rely on data from multiple PMUs, it is vital that the measurements taken from these different devices be time-aligned based on their original time-tag to create a system-wide snapshot of synchronized measurements as a collective group before they can be useful to these applications. The Phasor Data Concentrator (PDC) fulfils precisely this function. A phasor data concentrator collects phasor data from multiple PMUs or other PDCs, aligns the data by time-tag to create a time-synchronized dataset, and streams this combined dataset in real-time to the applications. To accommodate the varying latencies in data delivery from individual PMUs and to ensure that these delayed data packets aren't missed, PDCs typically buffer the input data streams and have a certain 'wait time' before outputting the aggregated data stream.

Since PMUs may utilize various data formats (e.g. IEEE 1344, IEEE C37.118, BPA Stream, etc), data rates, and communication protocols (e.g. TCP, UDP, etc) for streaming data to the PDC, the PDC must therefore not only support these different formats on its input side, it should be able to down-sample (or up-sample) the input streams to a standard reporting rate, and massage the various datasets into a common format output stream. Appropriate anti-aliasing filters should be used whenever the data is down-sampled. Furthermore, as there may be multiple users of the data, the PDC should also be able to distribute received data to multiple users simultaneously, each of which may have different data requirements that are application specific.

The functions of a PDC can vary depending on its role or its location between the source PMUs and the higher-level applications. Broadly speaking, there are three levels of PDCs (Figure 14- 4):

- ***Local or Sub-Station PDC:*** A local PDC is generally located at the substation for managing the collection and communication of time-synchronized data from multiple PMUs within the substation or neighboring substations, and sending this time-synchronized aggregated dataset to higher level concentrators at the control center. Since the local PDC is close to the PMU source, it is typically configured for minimal latency (i.e. short wait times). It is also most commonly utilized for all local control operations in order to avoid time delay from passing information and control decisions up through the communications and analysis system. Local PDCs may include a short-term storage to prevent against network failure. A local PDC is generally a hardware-based device that should require limited maintenance and can operate independently if it loses communications with the rest of the synchrophasor network.

- ***Control Center PDC****:* This PDC operates within a control center environment and aggregates data from multiple PMUs and substation PDCs primarily located within a utility's footprint. It must be capable of simultaneously sending multiple output streams to different applications, such as visualization and alarming software, databases, and energy management systems, each with its own data requirements. Control center PDC architecture must be able to parallelize in order to handle expected future loads with minimal overhead penalty, satisfy the high-availability needs of a production system, perform its duties regardless of vendor and device type, and should use a hardware abstraction layer to protect the end user or data consumer. PDCs must be adaptable to new protocols and output formats as well as interfaces with data-using applications.

- ***Super-PDC:*** A super-PDC operates on a regional scale and is not only responsible for collecting and correlating phasor measurements from hundreds of PMUs and multiple PDCs spanning several utilities; it may also be responsible for brokering the data exchange between these utilities. In addition to supporting applications such as wide-area monitoring and visualization software, energy management systems and SCADA applications, it should be capable of archiving vast amounts of data (several Terabytes per day) that is being gathered from the large number of PMU/PDC devices. Super-PDCs are therefore typically enterprise level software systems running on clustered server hardware to accommodate scalability to meet the growing PMU deployment and utility needs.

While some PMUs provide the ability to store many days of phasor data in the event of a communications failure, phasor data is typically stored at the PDC and/or super-PDC levels of the synchrophasor data system. Depending on the number of PMUs and the data rates, the volume of phasor data can quickly add up. This is illustrated in Figure 14- 5 which shows the amount of data produced (in kilobits per second) by differing numbers of PMUs at different sampling rates (assuming there are 20 measurements per PMU). Given the large volume of phasor data, data storage requirements can become significant. As an example, the Super-PDC operated by Tennessee Valley Authority (TVA) is presently networked to around 120 PMUs and is archiving approximately 36 GB per day.

13.2.3 Phasor Gateway and NASPInet

Although PMUs of various WAMS are typically deployed and owned by the respective asset owners, such as transmission owners, there are many situations that the synchrophasor measurement data, as well as other types of data, messages and control commands will need to be exchanged between WAMS of different entities, such as among asset owners, between asset owners and ISOs/RTOs/RCs, between asset owners and research communities, and so on.

The data exchange needs among various types of WAMS of different entities are typically driven by the real-time applications of these WAMS. However, other types of data exchange needs also exist. One example is exchanging stored synchrophasor data for many offline post-event analysis and archiving applications. Many WAMS are also part of an integrated wide-area monitoring, protection and control system (WAMPACS). For such systems, data exchange needs among various WAMS/WAMPACS of different entities will also be driven by wide-area protection and control applications.

Depending on the types of the applications, the quality of service (QoS) requirements, such as latency, reliability, etc., for data exchange could be very different from each other.

One major concern for an entity to exchange data with other entities is the cyber security. Data should be provided to those that the data owner agreed to provide the data, and the entities that receive the data should also be assured that they are receiving the data from the data sources that they requested the data. The exchanged data could be used in mission critical applications, such as WAMS applications for assisting system operators in real-time decision making, or WACS / WAPS applications to perform real-time control and protection actions. Breach of security will expose the power grid to malicious attacks and illegal data access for unauthorized use.

Gateways can be used to shield entities from unauthorized access of their networks and provide a means to facilitate a secure and QoS assured data exchange among various entities.

The North American power industry has long recognized that existing inter-entity data exchange infrastructures, such as NERCnet for ICCP EMS/SCADA data exchange, are not capable to meet the above discussed data exchange needs. North American SynchroPhasor Initiative (NASPI) was created to facilitate "a collaborative effort between the U.S. Department of Energy, the North American Electric Reliability Corporation, and North American electric utilities, vendors, consultants, federal and private researchers and academics." NASPI's mission is "to improve power system reliability and visibility through wide area measurement and control. NASPI's ultimate objective "is to decentralize, expand, and standardize the current synchrophasor infrastructure through the introduction of a wide-area data exchange network across the entire North American continent (NASPInet)."

The Data and Network Management Task Team (DNMTT) of NASPI had undertaken the task to determine the overall requirements of the NASPInet and its general architecture. Its work had led to an envisioned NASPInet consisted of two major components, Phasor Gateways (PG) and a Data Bus (DB). The NASPInet Data Bus includes a NASPInet Wide Area Network (WAN) and associated services to provide basic connectivity, quality-of-service management, performance monitoring, information security management and access policy enforcement over different service classes of data exchanged through NASPInet. A NASPInet Phasor Gateway is the sole access point to NASPInet for an entity, which connects an entity to the NASPInet WAN and manages, in conjunction with NASPInet Data Bus services, the connected devices (PMUs, PDCs, Applications, etc.) on the entity's own network side, manages quality of service, administers cyber security and access rights, performs necessary data conversions, and interfaces with connected entity's own network.

Based on the extensive preliminary work of DNMTT of NASPI, US Department of Energy (DOE) funded a project to develop the NASPInet specification, which for PG and DB respectively.

NASPInet, as it is specified, will be a decentralized publish/subscribe based data exchange network. There will be no single centralized authority to manage the data publishing and subscribing. Instead, all subscriptions to any published data object (hereafter called as "signal") will be managed by the entity that publishes the data. The NASPInet DB services facilitate and data owners manage the data subscriptions of their published data through NASPInet PGs owned and operated by the data owners. Hence, we're slowly transitioning from the hierarchical "hub-n-spoke" type of an architectural design that comprised of the PMU $\rightarrow$

Substation PDC $\rightarrow$ Control Center PDC $\rightarrow$ Super-PDC, to a more distributed architecture consisting of the NASPInet PG and DB that integrate with the PDCs or directly with the PMUs in the field.

Though not explicitly defined in the specifications, the term of “signal” for NASPInet published/subscribed data objects is not restricted to synchrophasor data points only. A “Signal” of NASPInet could be any data object that will be exchanged across the NASPInet to support various wide-area monitoring, protection, and control applications, which could include but not limited to synchrophasor data, analog measurement data, digital data, event notification, control command, and so on.

To support the data publishing and subscription, each published signal must be uniquely identifiable across the entire NASPInet with all associated information of the signal. The associated information of a signal includes type of the signal, where it is generated, relationships with other relevant signals, ownership information, where data is published, and so on. For example, a synchrophasor data point generated by a PDC through down-sampling of a received synchrophasor input data point will need to provide such associated information, such as the signal type description (a synchrophasor; voltage or current measurement; positive sequence or single phase value; accuracy class; and reporting rate; etc.), the PDC ID to indicate where it is generated and to link it to its ownership information contained in the associated information of the PDC, the input signal’s ID to show its relationship with the input signal, and the publishing Phasor Gateway’s ID to indicate where the signal can be subscribed.

NASPInet requires a NASPInet signal to be published to go through a signal registration process before making it available for subscription and uniquely identifiable. The registration process is accomplished by the relevant Phasor Gateway that publishes it and the Name & Directory Service (NDS) provided by NASPInet's Data Bus. The signal registration process includes steps of publishing PG provides all associated information of the signal to NDS, NDS registering the signal by validating and storing all associated information in its metadata database, NDS assigning a 128-bit unique identification number to the signal, and NDS providing the unique signal ID to publishing PG for future reference to the signal.

There is a diverse range of wide-area monitoring, protection and control applications that can and will benefit from using wide-area measurement data exchanged across the NASPInet. Different applications could have very different Quality of Service (QoS) requirements on the data in terms of accuracy, latency, availability, etc. In NASPInet specifications, five general classes of data defined initially by DNMTT were described with desired QoS requirements, such as latency, availability, etc., specified. It is anticipated that the number of data classes, the definition of each data class, and the QoS requirements for each data class may change over time as NASPInet grows. However, NASPInet is required to ensure that QoS of each data subscription is satisfied when there are hundreds and thousands of concurrent active subscriptions for different data classes.

NASPInet is required to implement a comprehensive resources management mechanism to ensure the QoS of each subscription of any data class, which includes resource condition monitoring, resource usage monitoring, QoS performance monitoring, QoS provisioning, and traffic management.

NASPInet resource condition monitoring function monitors the conditions of each resource both in real-time and for historical archiving, including logging, reporting and alarming on any failure or out-of-service condition for any of NASPInet resources.

NASPInet resource usage monitoring and tracking functions must be able to track all resources that are involved in the data delivery chain from data entering NASPInet to data leaving NASPInet. The logged information enables detailed resource usage to be archived which can be used to determine instant, peak, and average loading level for each resource and so on.

NASPInet QoS performance monitoring function monitors the end-to-end QoS performance of each subscription from the publishing PG to subscribing PG. NASPInet QoS performance monitoring function achieves this through real-time QoS performance measurement, logging, reporting and alarming for each subscription. The logged information enables historical QoS performance information for each subscription to be archived and analyzed, and the aggregated QoS performance information for overall NASPInet to be derived.

Because resources usage may not evenly distributed and failure / outage may occur time to time, NASPInet resources management mechanism is required to implement a traffic management function for real-time traffic management during both normal and abnormal conditions based on the assigned priority level of each subscription.

To safeguard the reliable operation and secure the data exchange, NASPInet is required to implement a comprehensive security framework for identification and authentication, access control, information assurance, and security monitoring and auditing.

Only authorized devices/equipment can be connected to NASPInet and use NASPInet's resources. Users must also be authorized to use the NASPInet. Unauthorized connections or users should be detected and reported.

NASPInet must be able to securely authorize, assign, and authenticate each and every device/equipment connected to the NASPInet. For example, Data Bus must be able to securely authorize, assign, and authenticate each and every PG connected to it, and a PG must be able to securely authorize, assign, and authenticate each and every data generating/consuming device (e.g. PMU/application) that are connected on entity's own network.

NASPInet is required to be able to set and enforce the proper levels of access privileges and rights to each and every device/equipment connected to the NASPInet on an individual device/equipment basis, as well as to each and every user on an individual user basis. For example, a data publishing only PG shall not be able to subscribe to any data published by other publishing PGs, and a user authorized to access historical data only shall not be able to subscribe to any real-time data.

The NASPInet is required to implement information assurance functions to enable NASPInet guaranteeing the confidentiality and integrity of the data exchanged through NASPInet that include secure subscription setup, subscription based data and control flow security, key management, and information integrity assurance. These functions serve two main objectives: keep data and control flows from any unauthorized access and at the same time ensure that data and control flows have not been tempered with or degraded when traveling across the NASPInet.

One of the major challenges in NASPInet's implementation is to balance the requirement of using system resources more efficiently and simplifying the implementation and data handling under a one-to-many publish-subscribe scenario. It is anticipated that a real-time synchrophasor data stream published by a PG may be subscribed by many subscribers through many PGs. Under this condition, data multicast could be a very efficient mechanism to distribute data across the NASPInet with minimal bandwidth needs. However, in a generalized scenario, each subscriber may only subscribe to a subset of data contained in the data packet of the published data stream, while any two subscribers do not have exactly the same subset of data. Under this scenario, each subscription must have its own subscription key in order to ensure that other subscribers will not be able to know which data subset that it is subscribing.

13.2.4 Emerging Protocols and Standards

As communication requirements evolve, the standards community has been ready to update communication profiles to meet these requirements. One example of this is the recently developed IEC 90-5 report on Routed GOOSE and Sample Value datasets that is an upgrade to the IEC 61850 GOOSE and Sample Value profiles respectively.

The delivery of synchrophasor measurements is usually required at multiple locations including multiple utilities. The implementation of this requirement can be met through a Publisher-Subscriber architecture. The IEC GOOSE and Sample Values (SV) datasets are such mechanisms. The Generic Object Oriented Substation Event (GOOSE) is a user-defined dataset that is sent primarily on detection of a change of any value in the dataset. Sample Values (SV) is also a user-defined dataset, however, the data is streamed at a user-defined rate (e.g. – the reporting rate of the synchrophasors). These implementations achieve this functionality through the use of a Multicast Ethernet data frame that contains no IP address and not Transport protocol. As such, when a GOOSE or SV message reaches a router, the packet is dropped.

In order to address this issue, a new IEC 61850 routed profile has been defined. This profile takes either a GOOSE or SV dataset and wraps it in a UDP/ Multi-cast IP wrapper. The multicast IP address enables the router to "route" the message to multiple other locations. As a multicast message, the tendency is for the message to be sent everywhere in the network (which is not desirable). To address "where" the data is delivered, the involved routers must implement the Internet Gateway Management Protocol (IGMP) Ver 3. This protocol is initiated by the Subscribers in the system and enable the routers to "learn" the paths to which the Multicast message is to be routed.

Security is a key element in any communication system. To this end, the 90-5 profile implements authentication of a transmitted message and optional encryption of the same message. Authentication is achieved through the addition of a Secure Hash Algorithm (SHA) at the end of a message. The hash code can only be decoded through the use of the proper key. The 90-5 profile defines a Key Exchange mechanism that is responsible for delivering keys to all registered subscribers. Encryption of the "dataset" of the message is to be implemented using the Advanced Encryption Algorithm (AES). The same key that unlocks the hash code is used to decode the encrypted message. The Key manager is responsible for periodically updating the keys in the subscribers. If a subscriber is removed for the approved receive list, it is no longer updated with a new key.

13.3 WAMS Monitoring Applications

Some of the applications that are significantly improved or enabled by using PMUs include Angle/Frequency Monitoring and Alarming, Small Signal Stability and Oscillations Monitoring, Event and Performance Analysis, Dynamic Model Validation, Transient and Voltage Stability, Advanced System integrity Protection Schemes (SIPS) or Remedial Actions Schemes (RAS) and Planned Power System Separation, Dynamic State Estimation Linear State Measurements. Some of them are "low-hanging fruit" applications with lower deployment challenge (e.g. Angle/Frequency Monitoring and Alarming, Small Signal Stability and Oscillations Monitoring). Furthermore, to realize benefits of the above applications, it is necessary to place PMUs at optimal locations based on maximizing benefits for multiple applications. Those locations may also depend on leveraging existing or planned infrastructure, PMU placement in neighboring systems, and other factors such as upgradability, maintenance, redundancy, security, and communication requirements. Several of these applications are discussed in the following sections.

13.3.1 Angle Monitoring and Alarming

This section explains how synchrophasor angle measurements can be combined to indicate grid stress. It is convenient to assume a DC load flow model of the power grid. That is, the lossless grid has unity voltage magnitudes, and the voltage phasor bus angles θ are linearly related to the real power injections at buses. Transients in the synchrophasor measurements are allowed to settle before they are combined in order to indicate the steady-state stress.

13.3.1.1 Simple Case of a Double Circuit Line

Consider two equal transmission lines joining bus A to bus B. Suppose that synchrophasor measurements of the voltage phasor angles θ_A and θ_B are available. Then the stress on the lines can be measured by the angle difference $\theta_{AB} = \theta_A - \theta_B$. The angle difference θ_{AB} is proportional to the combined power flow through the two lines, but there is a distinction between monitoring the combined power flow and the angle difference. If one of the lines trips, the power flow from A to B remains the same, but the equivalent inductance doubles, the equivalent susceptance halves, and the angle θ_{AB} doubles. The doubling of θ_{AB} correctly indicates that the single line is more stressed than the two lines. Although this case is simple, it contains the essential idea of stress angle monitoring, and it can be generalized in two ways. The first way considers an angle difference between any pair of buses in the grid [11],[12],[17]. The second way generalizes to an angle difference across an area of the grid [13],[14],[15].

13.3.1.2 Angles between Pair of Buses

If A and B are any two buses in the grid with synchrophasor measurements, the angle difference $\theta_{AB} = \theta_A - \theta_B$ can be a measure of grid stress. The general pattern that large angle differences correspond to higher stress holds. The angle between two buses generally responds to changes throughout the grid. This makes it harder to interpret changes in the angle or to set thresholds for undue stress. This difficulty can be reduced by monitoring multiple angle differences between multiple pairs of buses. The data in time series of multiple angle differences can be examined for regularities such as typical ranges of values so that unusual stresses can be detected [16].

13.3.1.3 Angles across Areas

Consider an area of the grid in which there are synchrophasor measurements at all the buses at the border of the area (that is, all the area tie lines have a bus with synchrophasor measurements). The idea is to combine together the voltage phasor angles at the border buses to form a single angle across the area. The border buses are divided into A buses and B buses and the angle θ_{AB} across the area from the A buses to B buses is formed as a weighted linear combination of the border bus voltage angles [15]. For example, if the A buses are all north of all the B buses, then the area θ_{AB} from the A buses to the B buses measures the north-to-south stress across the area. The weights for combining together the border bus angles to calculate θ_{AB} are not arbitrary; they are specific weights calculated from a DC load flow model of the area. The area angle θ_{AB} behaves according to circuit laws, and this makes the area angle behave in accordance with engineering intuition. For example, the power flow north to south through the area is proportional to θ_{AB}, and the constant of proportionality is the area susceptance.

13.3.1.4 Internal and External Area Stress

The area stress and the area angle θ_{AB} are influenced both by power flows into the area through tie lines from other areas and powers injected inside the area, including the border buses. In fact [15], the area angle is the sum of an external stress angle due to the tie line flows and an internal stress angle due to powers injected inside the area:

$$\theta_{AB} = \theta_{AB}^{into} + \theta_{AB}^{area}$$

(2)

θ_{AB} can be obtained from the border bus angles, and, if the currents through the area tie lines are also measured by synchrophasors, then the external stress angle θ_{AB}^{into} can also be obtained. Hence (2) shows that the internal stress angle θ_{AB}^{area} can be obtained from measurements.

The internal stress angle θ_{AB}^{area} is useful because it only responds to changes inside the area. For example, if lines trip or power is redispatched outside the area, the internal stress angle θ_{AB}^{area} does not change. But the internal stress angle θ_{AB}^{area} changes if lines trip or power is redispatched inside the area. Therefore changes in θ_{AB}^{area} indicate changes in stress that can be localized to causes within the area. The localization makes θ_{AB}^{area} easier to interpret. The localization also holds for θ_{AB} in the special case that the area is chosen to stretch all the way across the power grid[13],[14]. In this special case, the area is called a “cutset area".

In summary, there are two ways to combine together synchrophasor measurements to monitor grid stress. The angle differences between multiple pairs of buses are simply obtained and this data can be mined to detect undue stress or unusual events. Computing the angle across an area is straightforward, but there are the additional requirements of synchrophasor measurements at all the buses along the border of the area and a DC load flow model of the area. The area angle obeys circuit laws and can give more specific information about events inside the area.

13.3.2 Small Signal Stability Monitoring

Time-synchronized measurements provide rich information for near real-time situational awareness of a power-system's small-signal dynamic properties via visualization and advanced signal processing. This information is becoming critical for the improved operational reliability of interconnected grids. A given mode's properties are described by its frequency, damping, and shape (i.e. the mode's magnitude and phase characterizing the observability of the mode at a particular location). Modal frequencies and damping are useful indicators of power-system stress, usually declining with increased load or reduced grid capacity. Mode shape provides critical information for operational control actions. Over the past two decades, many signal-processing techniques have been developed and tested to conduct modal analysis using only time-synchronized actual-system measurements [18]. Some techniques are appropriate for transient signals while others are for ambient signal conditions.

Near real-time operational knowledge of a power system's modal properties may provide critical information for control decisions and thus enable reliable grid operation at higher loading levels. For example, modal shape may someday be used to optimally determine generator and/or load-tripping schemes to improve the damping of a dangerously low-damped mode. The optimization involves minimizing load shedding and maximizing improved damping. The two enabling technologies for such real-time applications are a reliable real-time synchronized measurement system and accurate modal analysis signal-processing algorithms.

This section strives to provide an overview of the state-of-art and points the reader to more detailed literature. A starting point for the novice is reference [18].

13.3.2.1 Actual System Examples from the Western North American Power System

A power system experiences a wide variety of power oscillations:

- slow power oscillations related to mis-tuned AGC bias (typically 20-50 second period, or 0.02 to 0.05 Hz);
- inter-area electro-mechanical power oscillations (typically 1 to 5 second period, or 0.2 to 1.0 Hz);
- power plant and individual generator oscillations;
- wind turbine torsional oscillations (usually about 1.5 to 2.5 Hz);
- control issues in generator, SVC and HVDC systems;
- steam generator torsional oscillations (about 5 Hz, 9 to 11 Hz, etc.).

The oscillations are always there. For example, switching lights and starting / stopping electric motors cause momentary imbalance between electric demand and supply. If the system is stable, the power imbalances are settled in oscillatory way and are normally well-dampened. The concern is when the oscillations are growing in amplitude. The growing oscillations can result from power system stress, unusual operating conditions, or failed controllers (PSS, excitation, etc.). The system can either transient into the oscillation because of an outage / failure or slowly build into the oscillation because of an increased system stress or forced oscillation. A forced oscillation is a condition where an apparatus such as a generator controller has failed and is operating in a limit cycle. Growing power oscillations can cause line opening and generator tripping, and in the worst case, lead to cascading power blackouts. Another risk is that the interactions between oscillations can lead to major equipment damage. The most known phenomenon is sub-synchronous resonance when a generator torsional oscillation resonate with

LC circuits of series compensated lines, have the risk of breaking generator shaft or causing large over-voltages on the transmission system. Recently this phenomenon was observed with wind generators. In any case, it is very important to detect sustained or growing oscillations and to take mitigation actions.

13.3.2.1.1 Unstable Oscillation in the US Western Interconnection on August 10, 1996

On August 10, 1996, a major outage occurred in the Western Interconnection, breaking the interconnection into four islands, resulting in loss of 30,390 MW of load and affecting 7.49 million customers. A combination of line outages, heavy transfers, large angular separation across the system, low reactive support, and equipment control issues put the system at the edge of collapse. The instability manifested in collapsing system voltages and growing North-South inter-area power oscillations [19]. Figure 14- 6 shows a 500-kV bus voltage at the California - Oregon Intertie.

13.3.2.1.2 "Close Call" in the US Western Interconnection on August 4, 2000

On August 4, 2000, a poorly dampened oscillation was observed across the Western Interconnection following a loss of a 400 MW tie line between British Columbia and Alberta. The oscillation lasted about 60 seconds. Although the power flow on the California – Oregon Intertie was well within the operating limits, power exports from Canada to US were relatively high, and the relative phase angles between North and South were close to historic highs. The damping issues are more pronounced when the relative phase angles across the system are large. The event's response is shown in Figure 14- 7.

13.3.2.1.3 Forced Inter-Area Power Oscillation on November 29, 2005

A forced oscillation occurred in the Western Interconnection on November 29, 2005. The oscillation was driven by steam supply instability at Nova Joffre plant in Alberta. The plant has two gas turbines and a heat-recovery steam turbine. A fraction of the steam is typically sent to a process plant. An extractor control valve is set to keep the constant flow of steam to the process plant. Due to problems with a relief valve within the process plant, the extractor control valve began oscillating in a limit cycle at about 0.25 cycles per second. This resulted in power peak-to-peak oscillations of 15 to 20 MW observed at steam-turbine terminals. The power plant oscillation resonated with the North-South inter-area mode, causing peak-to-peak power oscillations on California – Oregon Inter-tie of 175 MW. This is shown in Figure 14- 8.

13.3.2.1.4 Boundary power plant oscillation on September 29, 2004

Boundary hydro-power plant is located in the north-eastern part of the state of Washington. The plant has six hydro-power units with the total capacity about 1,050 MW. The plant is connected to Canada by a 230-kV line. There are three 230-kV lines connecting Boundary plant with the Spokane, WA area, referenced as Boundary – Bell 230-kV lines. The Boundary - Bell lines are about 90 miles long and have tap points feeding local area 115-kV sub-transmission along the way.

On September 29, 2004, a tie line with Canada was out of service for maintenance, and Boundary power plant was radially connected to the Spokane area. A section of Boundary – Bell #3 line was also taken out of service for maintenance. Five out of six generating units were on-line. As the Boundary generation was ramping up to about 750 MW, the power oscillation developed at 0.8 Hz frequency. The oscillation was noticeable in Boundary 230-kV bus voltage, power plant output, and as far as Bell 230-kV bus voltage.

This Boundary plant oscillation was a classical example of a local electro-mechanical instability. The oscillation was the result of a weak transmission system due to several lines out of service. The appropriate operator actions were to reduce the power output until oscillation dampened and to operate at the reduced power output until the transmission lines are restored. This event is shown in Figure 14- 9.

13.3.2.1.5 Pacific HVDC Intertie (PDCI) Oscillation on January 26, 2008

On January 26, 2008, a sustained oscillation occurred at Pacific HVDC intertie. Transformer outages created a weak configuration on the inverter side, starting a high-frequency 4-Hz controller oscillation.

13.3.2.2 Response Types

Analyzing and estimating power-system electromechanical dynamic effects are a challenging problem because the system: is nonlinear, high order, and time varying; contains many electromechanical modes of oscillation close in frequency; and is primarily stochastic in nature. Design of signal-processing algorithms requires that one address each of these issues. Fortunately, the system behaves relatively linear when at a steady-state operating point [19].

We classify the response of a power system as one of two types: transient (sometimes termed a ringdown); and ambient. The basic assumption for the ambient case is that the system is excited by low-amplitude random variations (such as random load changes). This results in a response that is colored by the system dynamics. A transient response is typically larger in amplitude and is caused by a sudden switching action, or a sudden step or pulse input. The resulting time-domain response is a multi-modal oscillation superimposed with the underlying ambient response.

The different types of responses are shown in Figure 14- 10, which shows a widely published plot of the real-power flowing on a major transmission line during the Western Interconnection event in 1996. Prior to the transient at the 400 second point, the system is in an ambient condition. After the ringdown at the 400 second point, the system returns to an ambient condition. The next event in the system causes an unstable oscillation.

In terms of application, we classify modal frequency and damping estimation algorithms into two categories: 1) ringdown analyzers; and 2) mode meters. A ringdown analysis tool operates specifically on the ringdown portion of the response; typically the first several cycles of the oscillation (5 to 20 seconds). Alternatively, a mode-meter is applied to any portion of the response: ambient; transient; or combined ambient/transient. Ultimately, a mode meter is an automated tool that estimates modal properties continuously, and without reference to any exogenous system input.

13.3.2.3 Signal Processing Methods for Estimating Modes

Many parametric methods have been applied to estimate power-system electromechanical modes. As stated above, we classify these methods into two categories: ringdown analyzers; and mode meters.

Ringdown analysis for power-system modal analysis is a relatively mature science. The underlying assumed signal model for these algorithms is a sum of damped sinusoids. The most widely studied ringdown analysis algorithm is termed Prony analysis. The pioneering paper by

Hauer, Demeure, and Scharf [20] was the first to establish Prony analysis as a tool for power-system ringdown analysis. Many expansions and other algorithms have been researched since; the reader is referred to reference [18].

Ambient analysis of power-system data estimates the modes when the primary excitation to the system is random load variations, which results in a low-amplitude stochastic time series (ambient noise). A good place to begin ambient analysis is with non-parametric spectral-estimation methods, which are very robust since they make very few assumptions. The most widely used non-parametric method is the power spectral density [18] which provides an estimate of a signal's strength as a function of frequency. Thus, usually the dominate modes are clearly visible as peaks in the spectral estimate. While robust and insightful, non-parametric methods do not provide direct numerical estimates of a mode's damping and frequency. Therefore to obtain further information parametric methods are applied.

The first application of signal processing techniques for estimating modal frequency and damping terms from ambient data is contained in [21] where a Yule-Walker algorithm is employed. Many extensions and new algorithms have been explored since [21]; see [18] for an overview. This includes the Regularized Robust Recursive Least Squares (R3LS) method [22].

An important component of a mode-meter is the automated application of the algorithm. With all algorithms, several modes are estimated and many of them are "numerical artifacts." Typically, "modal energy" methods are used to determine which of the modes in the frequency range of the inter-area modes have the largest energy in the signal [23]. It is then assumed that this is the mode of most interest.

It is absolutely imperative to understand that because of the stochastic nature of the system, the accuracy of any mode estimation is limited. It is possible to significantly improve the estimation by exciting the system with a probing signal. A signal may be injected into the power system using a number of different actuators such as resistive brakes, generator excitation, or modulation of DC intertie signals. For example, operators of the western North American power system use both the 1400-MW Chief Joseph dynamic brake and modulation of the Pacific DC intertie (PDCI) to routinely inject known probing signals into the system [18].

13.3.2.4 Mode Estimation Example

As mentioned above, operators of the Western Interconnection periodically conduct extensive dynamic tests. These tests typically involve 0.5-sec. insertion of the Chief-Joseph 1400-MW braking resistor in Washington state; and probing of the power reference of the PDCI. The resulting system response provides rich data for testing mode-estimation algorithms. This section presents a few of these results.

Figure 14- 11 shows the system response from a brake insertion along with several minutes of ambient data. The signal shown is the detrended real power flowing on a major transmission line.

Two recursive mode-estimation algorithms are applied to the data: the RLS and RRLS [22] algorithms. The resulting mode estimates are shown Figure 14- 12 and Figure 14- 13. The damping estimates for the 0.39-Hz mode are shown as this is the most lightly-damped dominant mode. The results are compared to a Prony analysis of the ringdown. More detailed results are shown in [22]. The RRLS algorithm provides a more accurate mode-damping estimate and the accuracy improves after the ringdown.

13.3.2.5 Estimating Mode Shape

Similar to the modal damping and frequency information, near-real-time operational knowledge of a power system's mode-shape properties may provide critical information for control decisions. For example, modal shape may someday be used to optimally determine generator and/or load tripping schemes to improve the damping of a dangerously low-damped mode. The optimization involves minimizing load shedding and maximizing improved damping. Mode shape can be estimated from time-synchronized measurements.

The first published approach for estimating mode shape from time-synchronized measurements is contained in [24]. Follow-on methods are contained in [25] through [28]. An overview is provided in [18].

Figure 14- 14 shows a control center implementation of small-signal stability monitoring displays.

13.3.3 Voltage Stability Monitoring

Voltage stability refers to the ability of a power system to maintain steady voltages at all buses in the system after being subjected to a disturbance from a given initial operating condition [29]. Principal causes of voltage instability are [29],[30],[31],[32],[33]: heavy load system operation conditions, long distances between generation and load, low source voltages, and insufficient reactive power compensation. It is considered as a major threat for secure power system operation in many power systems throughout the world. Voltage instability, resulting in voltage collapse, was reported as either main cause or being an important part of the problem in many partial or complete system blackouts. Some incidents are partly documented in [31]. Table 14- 1 lists some recent incidents, not summarized in literature so far (together with time frames and total load interruption) [36],[37],[38],[39].

Wide area voltage stability monitoring, detection and control schemes built around Phasor Measurement Units (PMUs) supported by adequate communication infrastructure basically offer two major advantages with respect to existing voltage stability monitoring, instability detection and control schemes:

- PMU is GPS time-synchronized instrument [34],[40] able to provide measurements at much higher rate of 10-120 samples/second and transmits them through a fast communication infrastructure to data concentrators. High sampling rates allow:
    - more accurate computation and better tracking of system stability degree,
    - better and more robust identification of parameters associated with stability degree computation,
    - anticipation (prediction) of short-term and long-term evolutions of chosen index.
- PMUs are time-synchronized with the precision of less than 1μs. Highly accurate time synchronization allows these devices deliver coherent (not average, due to skew time, as in traditional SCADA) picture of the full or partial system state. Consequently, all voltage stability indices computed from the knowledge of full or partial system state

benefit for this advantage. However, averaging if deemed useful is still possible with these devices (e.g. for voltage short term and long-term trending).

13.3.3.1 Description of Voltage Stability

Voltage instability essentially results from the inability of the combined transmission and generation system to deliver the power requested by loads [31] and is related to the maximum power that can be delivered by the transmission and generation system to the system loads. In order to establish power-voltage relationships and introduce the notion of maximum deliverable power, a simple two bus (generator-transmission line-load) system is considered (shown in Figure 14- 15).

Assuming that the load behaves as an impedance with constant power factor ($X = R\tan\theta$) and using basic circuit theory equations for this system, active power consumed by the load can be expressed as,

$$P = -\frac{RE^2}{(R_l+R)^2+(X_l+R\tan\theta)^2} \tag{3}$$

Taking derivative of active power with respect to R and equalizing it with zero gives that at the external conditions (maximum deliverable power) holds,

$$|\bar{Z}_l| = |\bar{Z}| \tag{4}$$

or, maximum power that can be delivered to load is achieved when the load impedance is equal in magnitude to the transmission impedance [30],[31],[32].

If no assumption is made about the load (impedance behavior) the maximum deliverable power can be derived from power flow equations for simple two bus system. Active and reactive powers consumed by the load can be expressed as,

$$P = -\frac{EV}{X}\sin\theta \tag{5}$$

$$Q = -\frac{V^2}{X} + \frac{EV}{X}\cos\theta \tag{6}$$

Based on these two equations, the following power-voltage relationships can be established,

$$V = \sqrt{\frac{E^2}{2} - QX \pm \sqrt{\frac{E^4}{4} - X^2P^2 - XE^2Q}} \tag{7}$$

Assuming again constant load power factor, increase in active load power, and expressing load voltage magnitude as a function of this power results in well-known PV curve illustrated in Figure 14- 15. PV curve gives relationship between voltage magnitude and active power of combined generation and transmission system. The system equilibrium is at the intersection of the PV curve and load characteristic. As shown in the figure, for each load active power there are two operating points (A and B in Figure 14- 15). Point A, characterized by high voltage magnitude and low current is normal operating point while point B, characterized by low voltage magnitude and high current for the same load power is generally not acceptable. Point C corresponds to the maximum deliverable power where two operating points coalesce. An attempt to operate the system beyond maximum deliverable power will generally result in voltage instability. This happens for two reasons:

– due to smooth parameter (system load) changes, and
– due to disturbances which decrease the maximum deliverable power.

This is illustrated in Figure 14- 16. If the load is of constant power type, with the increase in load active power the system reaches maximum deliverable power (point C in Figure 14- 16) and this point corresponds to the voltage instability point (often referred as critical point) [30],[31],[33]. Beyond the critical point the system equilibrium does not exist. In the same figure dashed PV curve corresponds to post-disturbance system conditions (without a generator overexctitation limit (OEL)) depicting a decrease in maximum deliverable power. Further decrease in the maximum deliverable power (at higher voltage magnitude) is experienced if a generator OEL is activated (dash-dotted line in Figure 14- 16).

If the load is not of constant power type (Figure 14- 16) the critical point does not coincide with the maximum deliverable power and the system can operate at a part of lower portion of PV curve. However, the system operation at the lower portion of PV curve is generally not acceptable since the load would draw much higher current for the same power and for practical purposes voltage stability is associated with the maximum deliverable power.

13.3.3.2 Voltage Stability Monitoring and Instability Detection

Voltage stability monitoring is a process of continuous computation of the system stability degree, which can be seen as monitoring chosen stability index. The voltage stability index needs to reflect dominant phenomena linked to voltage instability in a particular power system and at the same time to be simple and practical for deployment. A wide variety of voltage stability indices have been proposed so far [30],[31],[41]-[51]. These indices serve as a measure of the proximity to the voltage instability (degree of system stability) by mapping current system state into a single (usually scalar) value. They are defined as a smooth, computationally inexpensive scalar with predictable shape that can be monitored as system operating conditions and parameters change [45].

In principle, any stability index could be used within voltage stability monitoring scheme but the following show the best promises to be used to this purpose:

- ***Voltage Magnitudes at Critical Locations (Key Load Center and Bulk Transmission Buses):*** This is the simplest approach and consists of monitoring voltage magnitudes at critical locations and their comparison with pre-determined thresholds. Voltage magnitude is not a good indicator of the security margin available at an operating point. On the other hand, when the system enters an emergency situation low voltage of the affected buses is the first indication of an approaching collapse [30],[31]. Short-term (about one minute using PMUs) and long-term voltage trending plots [52] are near-term applications of synchrophasor technology easy to deploy for voltage stability monitoring and detection.
- ***Voltage Stability Indices Derived from Thevenin Impedance Matching Condition***[42]-[48]*:* Essentially, these indices measure stability degree of individual load buses (or a transmission corridor) by monitoring the equivalent Thevenin impedance of the system and equivalent impedance of local load (magnitude of these values are equal at the voltage instability point). Furthermore, stability degree can be expressed in terms of local voltage magnitude and voltage drop across the transmission path as well as in terms of power margin (MW or MVA). Computation of these indices does not require system model.
- ***Loading Margin of an Operating Point Computed as the Amount of Load Increase in a***

Specific Pattern that Would Cause Voltage Instability: This index is based on physical quantities (usually MW) and as such easy to interpret and practical. Load margin computation requires system model (power flow model) and computation is performed using: repetitive power flows, continuation power flows [53] specifying the load (at one load bus, region, or the system) as continuation parameter, or direct method [54] solving equations describing the system model at the critical point. Sensitivity of computed margin with respect to any system parameter and control is easy to compute [55]. However, the computational costs are considered as the main disadvantage of this index [48].

- ***Singular Values and Eigenvalues***: The focus is on monitoring the smallest singular value or eigenvalue of the system Jacobian matrices (usually power flow Jacobian is satisfactory for this purpose). These values become zero at the voltage instability point. Involved computations require system model and is often associated with higher computational costs [30],[32],[47].
- ***Sensitivity based Voltage Stability Indices:*** These indices relate changes in some system quantities to the changes in others. Different sensitivity factors can be used to this purpose [30],[33],[41]. However, some studies suggest the sensitivities of the total reactive power generation to individual load reactive powers as the best choice since these sensitivities are directly related to the smallest eigenvalue of Jacobian matrix and are computationally inexpensive. Computation of these indices requires system model [30],[47].
- ***Reactive Power Reserves:*** Considerable decrease in reactive power reserves of system's key generators is a good indicator of system stress. Computation of reactive power reserves requires placement of measurement devices at several locations, does not require system model, and in principle cane make use of both SCADA and PMU-based measurements

[49],[50].

- ***Singular Value Decomposition (SVD) applied to a Measurement Matrix:*** The focus is on computing and tracking the largest singular value of the matrix. Measurement matrix is constructed from PMU measurements such that each column is a stacked vector of the available PMU measurements over a time window (2 to 3 times the number of available PMUs) [51]. This matrix is updated as soon as new vector of measurements is acquired. Involved computations do not require system model [51].

Computation of chosen voltage stability index can be complemented with the stored results of off-line studies and observations. These results provide thresholds for chosen index. Another way to monitor voltage stability would be to use off-line observations (without computation of a voltage stability index) in order to build, periodically updated to account for changing system conditions, statistical model of the system and use it together with machine learning techniques such as decision trees, neural networks, and expert systems. The simplicity of decision trees (DTs) and easy interpretation of the decisions made, offer it as an attractive alternative for voltage stability monitoring [56]. DTs are automatically built off-line on the basis of learning set and a list of candidate attributes are further used in real-time to assess quickly any new operating state, in terms of the values of its test attributes. In principle, DTs do not require synchronized measurement. SCADA measurements are enough since time skew should not be critical. However, they certainly can take advantage of these advanced measurements [56].

On-line voltage security assessment (VSA) tools can be used at the control center to measure the distance to voltage instability at any specific point in time (Figure 14- 17). In this case, real-time measurements provide the base case and permit computation of the stability degree for base case and any postulated scenario. Commercially available VSA tools are still to be adapted in order to take advantages offered by PMUs [30],[33],[57],[58].

Voltage instability detection is usually based on simple comparison of computed values of chosen index with its pre-defined thresholds. These thresholds are usually set pessimistic with respect to the theoretical values to allow timely detection of developing instability. On the other hand, some indices do not require any threshold but rely on the change in sign (most of sensitivity based indices). Theoretical criteria for instability detection of above mentioned indices are listed in Table 14- 2.

Voltage trending application is strongly related to the use of voltage magnitudes as voltage stability index and when properly tuned this application could provide an early detection of developing instability. In addition, this application could be complemented by the computation of the sensitivities of voltage to active and reactive load powers (model-free sensitivities) that could be also used to measure the system stress and detect approaching instability [52]. Several voltage stability indices can be combined to define an efficient monitoring and detection scheme [46].

Figure 14- 18 shows two control center implementations of voltage stability monitoring displays [59], [60].

13.3.4 Transient Stability Monitoring

This section describes how synchrophasors can be used for transient and damping stability assessment of multi-machine power systems following large, nonlinear disturbances. Broadly speaking, transient stability is defined as the ability of the synchronous generators in a power system to synchronize with each other asymptotically over time from any arbitrary asynchronized state after being perturbed by some major disturbance. In the 1970's the concept of energy functions was developed as a useful tool for such transient or synchronous stability analysis using passivity theory, the first two seminal papers being [18],[61] followed by detailed methods for construction of energy functions in [62]. Viewing a power system equivalently as a network of coupled nonlinear oscillators, energy function is generically defined as the sum of its transient kinetic and potential energies capturing its cumulative oscillatory behavior, and can be used as a very useful metric to quantify the system's dynamic performance following a fault. In this chapter, we address the problem of constructing such energy functions using Synchrophasor measurements with a particular focus on systems that are defined by predominantly two oscillating areas, or equivalently one dominant *inter-area* mode, as in Figure 14- 19(a). The validity of this approach is based on dominant power transfer paths being able to be separately modeled as interconnections of two machines or two groups of slow-coherent machines. Under such ideal conditions, the voltage and current phasor data from disturbances are used to estimate the swing energy associated with the disturbance and the quasi-steady state of the angular separation across the transfer path. The idea is illustrated on actual data recorded during a disturbance event in the WECC system.

13.3.4.1 Transient Stability Monitoring via Energy Functions

The study of energy functions stems from the fundamental swing dynamics defining the electromechanical motion of synchronous machines in any *n*-machine power system, given by Newton's laws of angular motion as

$$2H_i\Omega\ddot{\delta}_i = -d_i\omega_i + \underbrace{\sum_{j\neq i} E_iE_jB_{ij}(\sin(\delta_i-\delta_j)-\sin(\delta_{ij}^*))}_{u_i} \tag{8}$$

for, $i=1, 2,\ldots, n$, where H_i, δ_i, ω_i, E_i, d_i, u_i denote the inertia, rotor angle, rotor speed, machine internal voltage, damping coefficient and driving input for the i^{th} machine, respectively, and $\Omega=120\pi$ is a conversion factor from per unit to rad/sec. B_{ij} is the admittance between i^{th} and j^{th} machine, and δ^*_{ij} is the equilibrium angle between them before the disturbance. Considering every pair of machine, the energy function for the entire system can then be written as [63]

$$S = \underbrace{\sum_{i=1}^{n}\Omega H_i\omega_i^2}_{KE} + \underbrace{\sum_{k=1}^{n(n-1)/2} E_iE_jB_{ij}\int_{\delta_{ij}^*}^{\delta_k^*}(\sin(\delta_i-\delta_j)-\sin(\delta_{ij}^*))d\sigma}_{PE} \tag{9}$$

where, KE stands for kinetic energy and PE for potential energy. For the two-machine radial system shown in Figure 14- 19(a), substituting $n=2$, the equivalent expression in (9) reduces to

$$S = H\Omega\omega^2 + \frac{E_1E_2}{x_e}\left(\cos(\delta_{op}) - \cos(\delta_{op}) + \sin(\delta_{op})(\delta_{op}-\delta)\right) \tag{10}$$

where, $H = \frac{H1H2}{H1+H2}$ is the equivalent inertia for the single-machine infinite bus representation of the two-machine system, jx_e is the equivalent reactance of the transmission line connecting the two equivalent machines, and $\delta=\delta_1-\delta_2$. However, we must remember that each of the two equivalent machines in Figure 14- 19(b) represent the slow coherent representation of several local machines inside each area as a result of which the bus voltages contain high-frequency local modes as well as slower inter-area modes. These fast and slow components need to be separated, before using the voltages to construct the *inter-area* energy function that can serve as a performance metric for monitoring the wide-area transient stability of this two-area system. We call the filtered slow component of the voltages as the quasi-steady states $\bar{V}_1$ and $\bar{V}_2$. In real time, the post-fault equilibrium angle δ_{op} or θ_{op} is not fixed either, but rather time varying, due to turbine-generator governing and other generation and load changes. Thus we can write,

$$\delta = \hat{\delta} + \delta_{qss} \tag{11}$$

where, $\hat{\delta}$ and δ_{qss} are, respectively, the swing component and the quasi steady-state component of δ. We need to extract the quasi steady-state value in order to approximate the post-disturbance equilibrium angle δ_{op} used in the energy function (10).

Based on the discussion above, the following transient *inter-area* swing energy function

$$\bar{S} = H\Omega\omega(t)^2 + \frac{\bar{E}_1\,\bar{E}_2}{x_e}\left(\cos\left(\delta_{op}\right) - \cos(\delta(t)) + \sin\left(\delta_{qss}\right)\left(\delta_{qss} - \delta(t)\right)\right) \tag{12}$$

can be proposed to model the energy excited in the system due to the dominant inter-area mode. Here, δ_{qss} is obtained by bandpass filtering of the measured response of $\delta(t)$ from PMUs. This, in turn, can serve as an effective performance metric for monitoring whether the two areas will synchronize with each other, in a *wide-area* sense, following any major disturbance.

13.3.4.2 Applications to US Western North American Power System

We next use Synchrophasor data from a disturbance event in the US Western Interconnection to illustrate the construction of energy functions for a radial transfer path in this system. The variations of the bus angular separation and the bus frequency difference over time are shown in Figure 14- 20(a) and Figure 14- 20(b). The machine speed difference is mostly mono-modal, but the angle difference θ shows a distinct quasi-steady-state variation. Bandpass filtering is used to separate the oscillation and the quasi-steady-state components of $\delta(t)$. The swing component is shown in Figure 14- 20(c). For the post-disturbance case, we get x_e = 0.077 pu from the least squares fitting, and the equivalent machine inertia is estimated to be H = 119 pu. Figure 14- 20(d), Figure 14- 20(e), and Figure 14- 20(f) show the kinetic energy V_{KE}, potential energy V_{PE} and the total swing energy V_E, which is the sum of the two. Note that oscillations are clearly visible in V_{KE} and V_{PE} and yet they literally disappear when they are added together to form V_E. The oscillation is small-signal stable, although the damping is very low, and V_E eventually decays to a level commensurate with random perturbations on the system. If the system were negatively damped, V_E would grow to instability. The quasi-steady state angle δ_{qss} indicates that the sending end and receiving end of the transfer path remain synchronized, and, therefore, is transiently stable. A sudden increase in δ_{qss} indicates the loss of a portion of the transmission system or the loss of generation at the load bus, both of which would stress the transfer path. If the disturbance had caused a separation of the transfer path, δ_{qss} would grow as synchronism would be lost.

13.3.5 Improved State Estimation

Conventional static state estimators enhanced with a few strategically placed synchronized phasor measurements have offered some improvements in state estimation. However, state estimators based entirely on synchrophasor measurements will produce a fundamental change in state estimation and its applications. For example, the EHV lines and buses in many systems can be considered to be a network with injections from the lower voltage portion of the system. If a sufficient number of bus voltages and line currents are measured in rectangular form then there is a linear relationship between the bus voltages (the state) and the measurements of the form

$$z = \begin{bmatrix} II \\ YA + Y_s \end{bmatrix} E + \varepsilon \tag{13}$$

Typically more PMUs are installed for practical reasons but the minimum number of substations with measurements of both bus voltages and line currents required to observe all the bus voltages in approximately one third the number of EHV buses. The quantities in (13) are complex; II is a unit matrix with rows missing where there are no PMUs. II and A are real with only 1s and 0s but z, E, Y and Y_s are complex. Y represents line admittances and Ys represents the shunt elements. With Y=G+jB, $Y=G_s+jB_s$, $E=E_r+jE_x$, $z=z_r+jz_x$ in real and imaginary form, (13) takes the form of (14) and the estimate is given by (16).

$$\begin{bmatrix} z_r \\ z_x \end{bmatrix} = \begin{bmatrix} \begin{bmatrix} II \\ GA+G_s \end{bmatrix} & \begin{bmatrix} 0 \\ -BA-B_s \end{bmatrix} \\ \begin{bmatrix} 0 \\ BA+B_s \end{bmatrix} & \begin{bmatrix} II \\ GA+G_s \end{bmatrix} \end{bmatrix} \begin{bmatrix} E_r \\ E_x \end{bmatrix} + \varepsilon \tag{14}$$

$$\mathbf{z} = \mathbf{Hx} + \boldsymbol{\varepsilon} \tag{15}$$

$$\hat{\mathbf{x}} = (\mathbf{H}^{\mathbf{T}}\mathbf{W}^{-1}\mathbf{H})^{-1}\mathbf{B}^{\mathbf{T}}\mathbf{H}^{-1}\mathbf{z} = \mathbf{Mz} \tag{16}$$

In (15), **z** is a vector of measurements including both voltages and currents, **x** is the state of the EHV system (the bus voltages in rectangular form), and $\boldsymbol{\varepsilon}$ is the vector of measurement errors with covariance matrix **W**. **W** is typically assumed to be diagonal ($w_{ii} = \sigma_i^2$, $w_{ij} = 0 \quad i \neq j$) i.e., the measurement errors are independent. The $\mathbf{W}^{-1}$ in (16) weights the difference between the actual measurements z and the estimated measurements $\hat{\mathbf{z}} = \mathbf{H}\hat{\mathbf{x}}$ with the variances giving more weight to measurements with small variances, i.e. the estimate minimizes $\sum \frac{(z_i - \hat{z}_i)^2}{\sigma_i^2}$

The matrix inverse in (16) is only symbolic. The Q-R algorithm or something equivalent is used to solve the set of over defined equations in (15). The **H** matrix and hence **M** are constant unless there are topology changes in the system. A topology processor can use breaker status if it is available from a “dual-use” line relay/PMU device or use line current measurements, if necessary, to track breaker status. The resulting estimator is linear (no iteration is involved). It can run as frequently as once or twice a cycle. It is truly dynamic, no static assumptions are involved, and the data is time tagged and organized by Phasor Data Concentrators (PDCs). A measurement vector corresponding to measurements with the same time tag is multiplied by a constant matrix (which changes with topology) to produce an estimate of the EHV voltages.

A second variation made possible with synchrophasor measurements in a three-phase estimator. Rather than combining the individual phase quantities to form a positive sequence voltage or current the individual phase measurements can be time tagged and communicated to the control center where an estimate of the individual phase voltages are computed with a matrix similar to M in (15) and (16) but with three time as many rows and columns. The three-phase estimator gives real time dynamic information about the origins and the magnitudes of imbalances in the network.

The three-phase estimator also has the ability to provide calibration of the PTs and CTs in the network. The concept of calibrating measurements is not new but there is not actually a positive sequence CT to be calibrated. In the three-phase formulation there are three actual CTs and PTs that have ratio errors.

With the notation of (15) the calibration problem is given in (17)

$$\mathbf{z} = \mathbf{KHx} + \boldsymbol{\varepsilon} \tag{17}$$

where K is a diagonal matrix of ratio correction factors. It is clear that with a k for every measurement that there are too many unknowns since if $\mathbf{K}$ and $\mathbf{x}$ are solutions then $\alpha\mathbf{K}$ and $\mathbf{x}/\alpha$ are also solutions. One ratio correction factor is taken as 1 (the voltage measurement is taken as being correct) and that k is removed from the set of unknowns. A precision PT or a new high quality CVT can be used for this purpose.

Each PTs and CTs has a ratio error of the form: Measurement= k* True where, k is the ratio correction factor is $k=|k| \angle\theta$. The estimation of all the xs and all the ks requires data over an extended time period over which the state of the system changes. The calibration is a batch solution for all the states over the period along with the ratio correction factors. It is also assumed that the system model is known and accurate, the ratio correction factors are constant, and that one PT is essentially perfect.

PMU--based, three-phase state estimation can be accomplished using a multitude of monitoring solutions. The improved state estimation methodology described in this section is being implemented as shown in Figure 14- 21. This diagram serves as a basic framework for substation PMU data. Existing serial communications, line voltages, line currents, etc. are not displayed.

The scale of the extra-high voltage (EHV) state estimation problem is well suited for the deployment of synchrophasor technology. Generally speaking, while electrical interconnections can be vast on any scale, the patchwork of EHV networks composing the interconnection are generally rather sparse when compared to their lower-voltage transmission and sub-transmission counterparts. For any arbitrary moderate to large utility within an expansive interconnection, there might exist hundreds of electric transmission substations at lower voltages (<345kV). For that same utility, however, there may only exist scores if not dozens of EHV stations. Tersely expressed, the PMU-based EHV state estimation problem can be addressed with a modest number of PMUs.

After identifying EHV stations to be monitored (resulting from a study to establish complete observability), two principles guide the selection of parameters to be monitored (Figure 14- 21). The following must be captured for each selected station:

1. Three-phase voltage measurements for every EHV bus element that can be isolated.
2. Three-phase current measurements for all electric transmission lines and transformers connected at the EHV voltage level. All injections into the EHV network must be captured.

In many cases, digital line relays can serve as "dual-use" line relay/PMU devices with minimal settings changes and/or upgrades. Older digital relays may require a "cradle swap" to install new relay hardware. In any case, a stand-alone PMU solution can be used to augment any monitoring solution chosen.

13.4 WAMS in North America

13.4.1 North American SynchroPhasor Initiative (NASPI)

The North American SynchroPhasor Initiative (NASPI) is a joint effort between the U.S. Department of Energy (DOE) and the North American Electric Reliability Corporation (NERC). The goal is to improve power system reliability through wide-area measurement, monitoring and control. This shall be achieved by facilitating a robust, widely available and secure synchronized data measurement infrastructure for the interconnected North American electric power system. It also includes associated analysis and monitoring tools for better planning and operation, and improved reliability.

To facilitate the development of synchrophasor technology, particularly to foster an environment of information exchange between utilities, the U.S. DOE initiated the Eastern Interconnection Phasor Project (EIPP) in October 2002, building on over a decade of experience in the western interconnection. In 2007, NERC formally joined DOE in the effort, and expanded it to include all interconnections within North America. At this time the EIPP was renamed to NASPI [64]. Updates of the NASPI program have been recently provided [65],[66],[67].

NASPI is structured as a working group made up of voluntary members from electric power operating organizations, reliability coordinators, suppliers of monitoring and communications network hardware and software, and researchers from industry, universities, and national laboratories. The working group is composed of five task teams who focus on various aspects of developing and deploying synchrophasor measurement technology. DOE, through the Consortium for Electric Reliability Technology Solutions (CERTS) and in collaboration with NERC, provides technical support to the task team activities. The task team leaders, together with the DOE program manager and representatives from NERC and CERTS, make up a Leadership Committee, whose role is to plan and coordinate the working group activities. An Executive Steering Group provides oversight to the working group and engages the power industry at a senior management level to spread the word about the benefits of system-wide measurements and enlists support for the program. Some of the more recent achievements of the NASPI initiative include:

- ***NASPInet Concept:*** Under the leadership of the NASPI Data and Network Management Task Team, the concept of a distributed architecture linking the providers of the data (publishers) with applications (subscribers) using a publish-and-subscribe middleware and data bus concept is under development. Currently, the NASPInet architecture is at a conceptual design phase, and a detailed specification is under development. The vision is that this specification can be used by hardware or software vendors to provide an interface to NASPInet, either as a publisher or as a subscriber. The unifying concept that will provide this interface is a phasor data gateway. The next stage of development will be pilot demonstration projects to further refine and modify this specification based on lessons learned from interconnecting multiple vendors and a spectrum of applications in a common architectural framework.
- ***System Baselining****:* Both the Planning and Operations Task Teams are currently involved in baselining activities, or, in other words, determining "normal" phase angles so that abnormal conditions can be better defined and alarmed. The task teams are taking complimentary approaches to determining these "normal" phase angle separations. The Operations Task Team is looking at observed angle separations for key phasor measurement locations, and evaluating this data over historical timeframes. The Planning Task Team is performing model-based studies to assess the phase angle separation under known heavily stressed conditions, and correlating these angles with specific changes to the operating conditions in the basecase model study. Between these two approaches, the goal is to develop a more

rigorous methodology for determining the thresholds at which the real-time monitoring tools should be alarmed based on the observed phase angle separation between monitoring locations.

In the US, DOE has also provided major stimulus with Smart Grid Investment Grant (SGIG) projects to speed-up the deployment of PMU systems:

- WECC WISP (250 new PMUs) – $108 M (including PG&E, BPA, SCE, SRP)
- PJM (90 new PMUs) – $ 40 M
- NYISO (35 new PMUs) – $ 76 M
- Midwest ISO (150 new PMUs) – $ 35 M
- ISO New England (30 new PMUs) – $ 9 M
- Duke Energy Carolina (45 new PMUs) – $ 8 M
- Entergy (18 new PMUs) – $ 10 M
- American Transmission Company – (5 new PMUs) – $ 28 M
- Midwest Energy (1 substation) – $ 1.5 M

13.5 WAMS Worldwide

13.5.1 WAMS Applications in Europe

Due to the challenging system operation conditions for European Transmission System Operators (TSOs) within the last few years as well as to modern technology and related software currently available at reasonable prices, substantial progress regarding dynamic system analysis tools has been reached. While, PMU based WAMS is a key component of these applications, as a result of different application requirements and strict rules concerning the security of data exchange, two main categories of applications have been set up independently:

- Research and development or demonstration projects
- Industrial and TSO applications

13.5.1.1 Research and Development Projects

Such systems are mainly used by universities, which exchange their measurements via the public internet. The measurement equipment and the required software for data acquisition and analysis are either based on development work of their own or comprise a combination of standard software and WAMS from leading manufacturers. As the related measurements are mainly from the distribution system, only frequency, voltage and voltage phase angle are used for analysis and research.

13.5.1.2 TSO Applications

In the European TSO community WAMS based on different technologies have been installed. On the one hand there are stand-alone transient recorders, the measurements of which require remote collection and subsequent manual synchronisation with measurements from other substations, on the other hand there are systems where PMU and PDC technology provide for automatic and on-line data synchronization and analysis.

Common applications for both solutions are:

- Dynamic model validation based on post-mortem dynamic system analysis

- Monitoring of dynamic system performance

It is obvious that the second technology offers a wider range of applications, which are in use today:

- voltage phase angle difference monitoring
- line thermal monitoring (medium value between two substations)
- voltage stability monitoring (online P–V curves)
- online monitoring of system damping (online modal analysis with online parameter estimation
- intelligent alarming if pre-defined critical levels are exceeded
- online monitoring of system loading

TSOs have already started to include some of the measurements, information and alarms output by the WAM system within their SCADA systems, too.

Although the TSOs currently focus on using their WAMS mainly for their own system operation purposes, a few TSOs have already started to exchange PMU measurements between their PDCs. Swissgrid, being one of the driving forces for the application of the WAMS technology, has established links to eight European TSOs, see Figure 14- 22.

Based on this system, a continuous dynamic monitoring of the Continental European system is performed.

13.5.2 WAMS Applications in Brazil

Brazil is the biggest country in South American continent and its main electric energy source come from hydroelectric plants (more than 90% of all produced electric energy in 2010). The hydro generation park is formed by power plants in cascade along 12 major hydrographic basins spread all over the Brazilian territory and many of these hydro plants are distant from the main load centers which are situated in the Southeast region. Due to the extension of the Brazilian territory, the rainfall profiles are complementary among geographic regions and variable over the year, as well as between dry and wet years. Thus, one of the main challenges for the Brazilian Power System operation is to optimize the available hydro resources, considering each river with their cascade power plants, the diverse energy production in each region, the existing transmission restrictions and complementing the energy production with other energy resources (thermal, nuclear, wind, biomass, etc.), in order to obtain the minimum production cost while maintaining the system reliability. Some of the biggest hydroelectric plants in Brazil (like Itaipu and Tucurui) are located far from the load centers, resulting in bulk power transfers over long distances. Even in the next future, this picture will not change so much, as the most relevant power plants under development are located in the Amazon region, far from the main load centers by approximately 3,000 kilometers.

As in all systems of this proportion, disturbances due to significant generation and load unbalances may cause excessive frequency variations, voltage collapse situations and even the splitting of certain parts of the network, with loss of important load centers.

The sole independent power system operator in Brazil (ONS) has been investigating the effective use of synchrophasor technology in power system operation and is leading a major industry effort to deploy a large scale synchrophasor measurement system (SMS) for the Brazilian interconnected power system [68]. In this effort, ONS conducted the first round of certification tests on commercial PMU models. These tests were performed to guarantee smooth system integration and the global performance of the SMS, considering that it will be a multi-owner system and will need to use PMUs from diverse manufacturers. The results from these testes has shown that nowadays synchrophasor technology is ready to be applied for wide-area monitoring and situation awareness applications, but the technology needs to evolve in order to allow more reliable real-time applications and wide-area protection and control applications [69]. The on-going revision of the IEEE C37.118 standard surely will solve most of the current issues and will provide more adequate characteristics suitable for protection and control applications.

Considering the present technological status, the Brazilian WAMS will be used initially as a long term system dynamics and event recording system for post-mortem analysis, model validation, and mitigation solution investigation, but it is also expected to add synchrophasor applications to support the real-time power system operation.

As a result of a research project, ONS has identified a number of candidate synchrophasor applications, and selected four applications for a proof-of-concept pilot implementation:

- ***System Stress Monitoring (StressMon)***: During times of normal or abnormal operation the angle difference between two locations in the transmission system could be used to measure how much margin there is between the current operating conditions and an operating condition that would be impacted by either pre-determined pre or post contingency stability violations. Phase angle differences between a limited number of pre-selected PMU locations would provide a measure of the overall condition of the power system. StressMon is a tool to monitor angle difference between pairs of locations or regions in the power system to detect proximity of predefined stability limits. Monitoring should consider trespassing of limits and deviation from forecasted reference values. Results can be used for decision support in real-time or for off-line auditing.

- ***Closing a breaker in a loop in the transmission network (LoopAssist):*** Closing the breaker may cause an overload, when the phase angle difference across the breaker is too large. Also system stability may be affected or damage may occur to power system equipment. When closing a parallel connection in a transmission network (closing a loop) the phase angle across the circuit breaker provides a good measure for the impact of the control action. LoopAssist is a tool Monitor voltage magnitude and angle difference across circuit breakers involved in closing transmissions loops in the power system. This function can be useful for providing a means to guide the operator on conditioning the power system for a valid reconnection situation avoiding overloads or to provide a measure of the impact incurred in closing a loop in the system. Results can be used for decision-support in real-time or for off-line auditing.
- ***Closing a connection between two electrical islands (SynchAssist):*** When closing a tie-line between two electrical islands, a synchronism check relay may block the control action when the conditions for synchronization are not satisfied. Typically the relay will verify the synchronization conditions before allowing breaker closure to take place, based

on frequency deviation; phase angle difference and voltage magnitude difference. Showing the variation of the phase angle between the two islands in a time trend together with numerical values for the above criteria together with some other numerical values (e.g. actual generation and access synchronized generation capacity in both electrical islands) provides useful information for the operator to make an informed decision when to issue the breaker control action. When no synchronism check relay is available at the substation where the breaker is located, monitoring the periodic oscillation of the phase angle difference will provide an indicator when to issue a control action from the SCADA system. SynchAssist is a tool to monitor voltage magnitude difference, angle difference and frequency deviation across transmission equipment involved in reconnecting electrical islands in the power system. This tool can be useful for providing information to guide the operator on conditioning the power system for a valid reconnection situation, by avoiding unstable situations, cascading events, or severe overloads. Results can be used for decision-support in real-time or for off-line auditing.

- ***System Oscillations Monitoring (DampMon):*** Synchrophasor measurements can be used to monitor oscillations in power system quantities. These quantities can be raw or filtered phasor measurements or quantities calculated from phasor measurements such as line flows or corridor flows. Power system oscillations are usually initiated by sudden changes in the power system such as fault clearing, line switching or generator tripping. These events cause generator shaft oscillations that are usually damped within a very short period of time (seconds) however when a system is heavily loaded these oscillations can become poorly damped. In addition, even without these events it is possible that in heavily loaded systems oscillations occur. This application would calculate the amplitude of the oscillation using phasor measurement in real time on a sample-by-sample basis. It would further calculate the characteristic frequency and damping factor of the power oscillations. All three values would be displayed in real time, both as a trend display or as a numerical value in some format (e.g., bar-chart). The results may be used to show the oscillations of the relevant phasor measurements, phase angle differences, or calculated flows. DampMon is a tool to monitor oscillations in power system quantities. These quantities can be raw or filtered phasor measurements or quantities calculated from phasor measurements such as line flows or corridor flows.

To confirm the adequacy of these applications, they were implemented on an application test platform based mainly on the Control Center existing EMS system.

Another important synchrophasor application initiative in Brazil comes from the Santa Catarina Federal University (UFSC) [70]. The project started in 2001 as a research carried out jointly by UFSC and a Brazilian industry. In 2003, the project got financial support from the Brazilian government which allowed the deployment of a prototype synchrophasor measurement system. This first system measures the distribution low voltage at nine university's laboratories, communicating with a PDC at UFSC over the public Internet. This system allowed record the BIPS dynamic performance during the latest power system major disturbances. Currently, another project from UFSC have installed PMUs on three 500 kV substations in the South of Brazil.

13.6 WAMS Deployment Roadmap

As discussed, PMU applications offer large reliability and financial benefits for customers/society and the electrical grid when implemented across the interconnected grid. Synchrophasors enable a better indication of grid stress and can be used to trigger corrective actions to maintain reliability. As measurements are reported 10-120 times per second, PMUs are well-suited to track grid dynamics in real time. In general, this technology is instrumental for Improving wide area monitoring, protection and control. Considering a large number of existing and potential applications, benefits are grouped in four categories:

- Data Analysis and Visualization – Significant benefits have already been achieved.
- Outage Reduction and Blackout Prevention to improve System Reliability, including real-time control and protection – Huge societal benefits
- System Operations and Planning, including modeling and restoration– Enables a paradigm shift with tracking grid dynamics and system measurements vs. estimation.
- Market Operations and Congestion Management - large potential financial benefit as it enables to utilize accurate and optimal margins for power transfer (vs. worst case scenario presently used in practice).

Given the nature of PMU implementation requiring participation of broad base of users, the “overall industry roadmap” is an important step in designing and deploying large-scale PMU systems. NASPI has developed such a roadmap and is shown in Figure 14- 23. This roadmap, which is based on applications’ business needs, commercial availability and cost, and complexity with deploying those applications, was developed through an interview process with industry experts and users [71], [35]. The details of this roadmap are described below.

Firstly, industry needs are identified as (critical, moderate, unknown) regardless of the technology. Secondly, the value of the PMU technology, for each identified application, has been mapped related to importance in serving industry. This approach resulted in 4 categories: *Necessary and critical*; *Critical with added benefits*; *Moderate need with added benefits*; and *Requires more investigation*. Thirdly, deployment challenges have been mapped for each application (low, medium, high). The deployment challenges are defined based on technology (communications, hardware and software requirements) and applications status (commercially available, pilot installation, research, not developed).

The applications and infrastructure aspects (e.g. PMU locations, network & data storage) are grouped into near-term (1-3 years), medium-term (3-5 years) or long-term (more than 5 years). This roadmap focuses on business and reliability needs to commercialize and deploy PMU technology and applications addressing implementation risks. Applications in the near-term group reflect the immediate needs and deployment possibilities. Applications in the medium-term group largely reflect that even though the benefits are there, the commercial deployment is still further away due to deployment challenges and application commercialization. Applications in the long-term group indicate a combination of distant commercial status, extensive infrastructure requirements (and thus costs), and/or that lengthy field trials.

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Figures

Figure 14- 1 Wide Area Measurement System (WAMS).

Figure 14- 2 Integration of WAMS within an Advanced Visualization Framework.

Figure 14- 3 Building Blocks of a Generic Phasor Measurement Unit (PMU).

Figure 14- 4 The Three Levels of Phasor Data Concentrators: (1) Local or Substation PDCs, (2) Control Center PDCs, and Regional Substation PDCs.

Figure 14- 5 Data Produced by Different Numbers of PMUs and Sampling Rates (Kilobits/second).

Figure 14- 6 Malin 500-kV Bus Voltage, Unstable Oscillation during August 10, 1996 Outage.

Figure 14- 7 Malin 500-kV Bus Voltage, August 4, 2000 Event.

Figure 14- 8 Forced Oscillations on California – Oregon Intertie on November 29, 2005.

Figure 14- 9 Growing Oscillations at Boundary on September 29, 2004.

Figure 14- 10 Real Power Flowing on a Major Transmission Line During the Western North American Power System Breakup of 1996.

Figure 14- 11 Brake Response of US Western Interconnection. Brake Inserted at the 300 sec. Point. Combined Ambient and Ringdown data from field measurements. Detrended Power Flowing on a Major Transmission Line.

Figure 14- 12 Frequency Estimation of the Major Modes using the RRLS Algorithm.

Tables