The Next Generation Energy Management System Design

Final Project Report

Power Systems Engineering Research Center

Empowering Minds to Engineer the Future Electric Energy System

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Energy Management System Design

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PSERC Publication 13-40

September 2013

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Power Systems Engineering Research Center

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Acknowledgements

This is the final report for the Power Systems Engineering Research Center (PSERC) research project titled "The Next Generation EMS Design" (project T-45). We express our appreciation for the support provided by PSERC's industry members and by the National Science Foundation under the Industry / University Cooperative Research Center program.

We wish to thank the following project advisors:

Jay Giri, ALSTOM Grid
Jim Gronquist, Bonneville Power Administration
Anthony Johnson, SCE
Innocent Kamwa, IREQ
Eugene Litvinov, ISO New England
Art Mander, TriState G&T
Kip Morison, BC Hydro
Mirrasoul Mousavi, ABB
Paul Myrda, EPRI
Naim Logic SRP
George Stefopoulos, NYPA
Michael Swider, New York ISO.

Executive Summary

Energy Management Systems (EMS) were invented in the seventies to add computationally intensive applications to the Supervisory Control and Data Acquisition (SCADA) Systems which were introduced as the core infrastructure for scanning the field data in the sixties. Over the last 50 years, many EMS functions were implemented and SCADA was further enhanced. Recently, limitations of low scanning capability of traditional SCADA became obvious and new substation Intelligent Electronic Devices (IEDs) such as Digital Protective Relays (DPRs), Digital Fault Recorders (DFRs) and Phasor Measurement units (PMUs) offered much better time resolution of the field measurements. Such developments led to a question addressed in this project: how should future EMS systems evolve assuming that new IEDs may be integrated in a common data measurement infrastructure?

This report is organized in eight sections. The first section presents the project objectives and a brief survey of the literature highlighting the various views on EMS enhancements. This section identifies the need for new EMS design with the following desirable features (a) integration of field data; (b) introduction of new decision-making tools based on data analytics for knowledge extraction; and (c) flexible implementation architecture that allows transition from legacy to new designs.

The second section presents a brief technical background of legacy EMS designs. The perspectives of original EMS architects on designing the original data acquisition system are discussed. The limitations of the conventional SCADA system in monitoring the system states comprehensively is identified as the root cause for redesigning the EMS system. The mismatch between legacy and new EMS design requirements affect data acquisition, data management, and communication architecture. This mismatch opens new opportunities for data acquisition system enhancements.

The third section introduces the technology developments in the field monitoring devices and the issues in the current power system operating paradigm. This section proposes integration of field data as the first step in the direction of improving the ability of operators to closely monitor power system operating states. An evolving three-stage design process is proposed which allows progressive improvements to accommodate the current expansions in the power systems embracing all the new technical developments without significant design transition cost implications.

The fourth section further focuses on enhancements in the existing design as a consequence of the data acquisition system technology improvements. This section illustrates the possibilities for enhancing the existing EMS design using intelligent alarm processor, topology processor and fault location accuracy improvements. Integration of field data (i.e., integration of IED and SCADA databases) is proposed to be the key step for improving operational visibility of the system. This section points out that consistent semantics modelling is essential for seamless integration of IED and SCADA databases.

The fifth section defines future EMS requirements in terms of spatio-temporal considerations of IED data integration and their impact on the communication architecture. It is emphasized that the future EMS design requirements should consider the temporal and spatial attributes of IED data sources. This section highlights the important temporal considerations which require special hardware implementations. Spatial considerations are shown to be very important for information exchange, models representation, and applications. The effect of huge volumes of data generated on key parameters of the communication architecture is discussed.

The sixth section is an elaborate discussion on the design of the communication architecture of the future EMS. Latency requirements of various applications are discussed. The evolving trend of wide area power system control towards distributed applications is surveyed. As the size of the system grows and the PMU data becomes available with faster data rates, the centralized operation and control will no longer be scalable. To address this need, a distributed architecture for communication, computation, and control is described. A method is developed to determine the parameters to simulate a communications system for a smart grid starting from the power network configuration and knowledge of the measurement data, as well as the on-line applications. Two simulation examples using the Western Electricity Coordinating Council (WECC) and the Polish systems are presented. The effect of communication latency on the design of wide area controllers is also demonstrated with an example of a damping controller. The ability of the centralized and decentralized communication architectures in meeting the latency requirements has been assessed using IEEE 118 bus test system.

The seventh section is devoted to the development of future EMS implementation strategies. "Closed life cycle" is identified as the fundamental design flaw in the conventional EMS design philosophy which paralyzes major upgrades in the system. A "spiral" architecture with three design stages is proposed as a better approach for the new EMS in order to embrace the new technology advancements with an open-ended life cycle. The three design stages allow seamless transition from legacy solutions to new designs through the use of interoperability standards. The first design stage allows significant improvements to legacy applications. The second design stage allows addition of new functionalities to the legacy EMS systems through an open deployment strategy. This section introduces four exemplary new EMS functionalities. The third design stage, called green field design, envisions adaptation of innovative IT and communication technologies for a completely new EMS design. Four exemplary green field design applications are also introduced in this section. A completely new EMS design platform called the Virtual EMS Design Platform is proposed in this section as an effective alternative to guard against natural disasters and terror attacks. A next generation Remote Terminal Unit (RTU) with fusion of various measurement technologies and relaying capabilities is proposed. A single next generation RTU is expected to replace various measurement devices in the field with integrated control and computational capabilities. It is also envisioned that these RTUs eliminate extensive communication and display infrastructures in control centres harnessing the potential of cloud based storage and high performance cloud computing with virtual 3D display technologies.

Finally, the eighth section concludes the report with a summary of the contributions from this project which are:

- The project identifies the following desirable features for the new EMS design a) integration of field data, b) introduction of new decision-making tools based on data analytics for knowledge extraction, and c) flexible implementation architecture that allows transition from legacy to new designs.

- Integration of field data i.e. integration of IED data base and SCADA data base is the key step for improving operational visibility of the system. Consistent semantics modelling is essential for seamless integration of IED and SCADA databases.

- The future EMS design requirements should consider the temporal and spatial attributes of IED data sources. The huge volumes of data generated by the new IEDs pose several challenges to the communication architecture.

- The future EMS communication architecture has to cater all the applications as and when needed with required speed and reliability. Average link bandwidth needed for smart grid applications should be in range of 5-10 Mbps for communication within one control area and 25-75 Mbps for inter control centre communications. Using meshed topology delays can be contained within the 100ms latency requirement satisfying all applications.

- For the case when the latencies are increasing beyond a feasible value, it is shown that distributed communication architecture with local control centres is a better choice.

- The implementation of future EMS design needs to take place in stages allowing seamless transition from legacy solutions to new designs through use of interoperability standards. A “spiral” architecture is envisioned to be a better approach for EMS deployment in order to embrace the new technology advancements with an open ended life cycle.

- A Virtual EMS Design Platform is proposed as an effective alternative to guard against natural disasters and terror attacks. This platform envisions development of a next generation RTU with fusion of various measurement technologies and relaying capabilities. This RTU is expected to eliminate extensive communication infrastructure and display infrastructure harnessing the potential of cloud based storage & high performance computing with virtual 3D display technologies.

Project Publications:

M. Kezunovic, "The Next Generation EMS Design," CIGRE Lisbon Symposium, Lisbon, Portugal, April, 2013.

M. Kezunovic and A. Bose, "The Future EMS Design Requirements", the 46th HICCS Hawaii International Conference on System Sciences, Hawaii, January 2013.

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1. Introduction

1.1 Background

1.2 Problem Statement

The concept of Supervisory Control and Data Acquisition (SCADA) system was introduced in the late sixties and subsequently the Energy Management System (EMS) solution with set of functionalities that relied on SCADA data was introduced in the seventies. This EMS design was based on the notion that power system goes through distinct states such as normal, alert, emergency and restorative, and hence the EMS functionalities need to support operators' ability to monitor the system behaviour as it goes through various operating states and make decisions to steer it back to the normal state. As the time went by, many things have changed in the area of power systems: introduction of the electricity markets to accommodate competitive trading, the growth of the power system infrastructure to meet demand for renewable resources, EMS technology to improve computations, communications and visualization, etc. As the central "nerve system" of grid operations and the open electricity market, Energy Management System (EMS) design is undergoing tremendous changes to meet the needs of the evolving utility industry. The SCADA solutions based on proprietary computer hardware and software made access to third-party software providers difficult.

Hence, almost 50 years after the initial proposals for the EMS solution as we know it today, the question whether we need a new EMS design and if so, how the next generation EMS design is going to look like may be raised. There are a few requirements of the next generation EMS design that are becoming rather obvious. They revolve around three simple questions: a) can the operator's ability to monitor the system be improved and how, b) what are the requirements for the better decision-making tools for the operators and how such tools may be implemented, and c) how the design may evolve from the current legacy design to the stages of future EMS implementation. This report is focused on trying to answer those three questions. Iintegration of emerging data acquisition infrastructures will be at the core of the new design since the level of investment in the legacy solutions will favor additions and retrofits of existing EMS design rather than totally new EMS solutions, at least for a foreseeable future.

1.3 Project Objectives

The project activity has addressed the following fundamental issues in the new EMS design:

- Data: the technological advancements in the data sources and flows. The impact of the new data on existing applications and integration of the new data sources.
- Information: extraction of information from new data, required visualization strategies, and effective utilization approaches.
- Knowledge: new tools for data analytics used for conversion of information to knowledge

- Communication Architecture: the communication architectures to cater the new data flows and control applications.
- Decision making: New applications supporting decision making for new business scenarios

1.4 Literature Review

The goal of the next generation EMS design was to provide open implementation platform [1]. This next generation EMS adopted advanced technologies such as relational database and 3-D graphic displays with much more mature and standardized SCADA functions [2].

Traditionally, Supervisory Control and Data Acquisition System (SCADA) measurements are sent to the energy management systems (EMS) every two to ten seconds [3]. This was considered sufficient since EMS was primarily designed for tracking normal and alert states. The fast development of computer, communication network, database technologies, and substation intelligent electronic devices (IEDs), as well as the new demands of electricity markets, makes developing a new generation EMS highly desirable [4]. The development is driven by the urge of electric power utilities to improve the service, and the need to accommodate new developments in a smart grid with penetration of smart sensors and distributed generation (DG) among others [5]. This leads to the need of much higher time resolution and precise time-synchronization in the SCADA measurements, as well as more powerful functionalities to deal with emerging monitoring, control and protection needs [6].

An expansion of current EMS applications has been proposed by many utilities as well as research organizations. In [7] the author discussed general requirements on retrofitting an Enterprise Energy Management (EEM) information system to support strategic energy management needs. B.C. Hydro proposed XEMS that features a data exchange interface with a legacy EMS and populates a relational database with the schematic of the Common Information Model (CIM) defined in IEC 61970 to drive a new EMS application in a remote Expansion System Server [8]. An N-EMS was designed to assist the temporal, spatial and objective applications of coordinated AVC and MW control, network re-modeling and on-line decision making [9]. All three designs are a retrofit of existing EMS for either enhancement of traditional or implementation of new application. A more evolutionary view of the EMS in the future is presented in [10] whereas [11] approaches the EMS design from the viewpoint of new and advanced power system applications in the EMS.

More recent discussions are aimed at a future EMS design where standardized solutions will enable additions of different measurement and data processing infrastructures leading to enhanced functionalities and novel designs [12]. So the integration of emerging data acquisition infrastructures will be at the core of the new design.

1.5 Conclusions

After 50 years of EMS legacy, the industry is facing a need for a new EMS design. This section identified the following desirable features: integration of field data, introduction of new decision-making tools based on data analytics for knowledge extraction, and flexible implementation architecture that allows transition from legacy to new design. The new EMS design requirements in the following sections essentially evolved from exploring these desirable features.

2. Technical Background

2.1 Limitations of the Original EMS Design

This section explains the main motivation of this report, which is to elaborate consequences of the mismatch between legacy and new EMS design requirements when considering data acquisition, management and communication architecture. This discussion leads to the need to specify the mentioned infrastructure for the future EMS design, which is the main contribution of this project.

2.1.1 Power System Operating Paradigm

Late sixties witnessed a major blackout in the State of New York, which had a lasting impact on how the power systems were to be monitored and controlled going forward [1]. Numerous studies where performed to set a new power system operating paradigm where Energy Management Systems would have a role of guiding operators through what was considered at the time critical power system operating states shown in Figure 1: Normal, Alert, Emergency and Restorative [6].

Two distinct power system management goals were firmly established with the EMS design: a) protective relaying, which operated autonomously and automatically and dealt with emergencies, b) energy management systems, which operated system-wide and included operators in the control loop to deal with planning, operations and system restoration. This separation meant that the protective relaying development, which was undertaken since the power systems were invented, would continue as an independent control infrastructure with separate wiring to the instrument transformers and circuit breakers, as well as other elements of the relaying solution such as communication systems, interlocking logic and alarm tagging. This opened a need to enhance SCADA infrastructure with several monitoring and control functions, which collectively were designated as Energy Management System.

The state of the art of the technology at the time when the original Remote Terminal Units (RTUs) and Supervisory Control and Data Acquisition (SCADA) systems were developed resulted in somewhat constrained design in comparison to what is feasible with today's technology. The RTU and SCADA designers' view at the time was that the following performance characteristics will be sufficient to allow operators to monitor the system, confirm validity of the operating and planning models, and execute control actions to maintain normal operation, steer the system conditions to prevent major blackouts, and successfully restore the system should it experience any emergencies:

- Collect analog measurements from instrument transformers and various sensors using transducers with rather limited frequency bandwidth around the fundamental frequency
- Collect status of circuit breakers through auxiliary contacts and deploy filters to eliminate impacts of contact bouncing

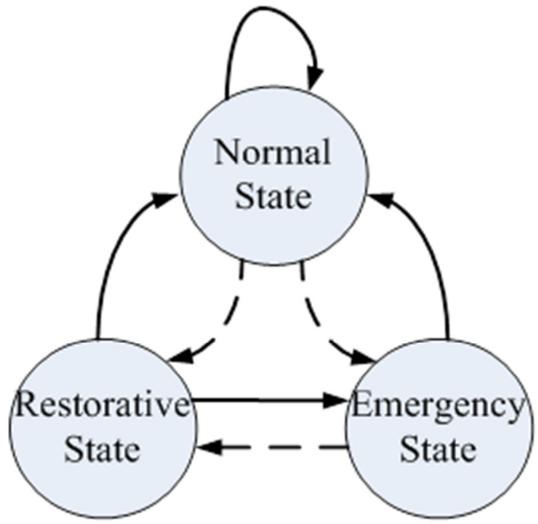


Figure 1 Paradigm for power system states affecting EMS functionality

- Scan analog measurements and contact state every 10-20 seconds by employing the logic of “reporting by exception” assuring that communication channels are not overloaded
- Time-tag new data scans at the SCADA database assuming that the time delays in the communication system will not affect data synchronization between substation events and the time data arrives to SCADA database

2.1.2 Field Data Monitoring Constraints

As a result of the mentioned design decisions for RTUs and SCADA, several data monitoring constraints were introduced:

- The analog-to-digital data conversion approach of scanning vs. synchronous sampling (utilized today and further explained later in the report), did not allow monitoring of phase relationships between the three phase measurements of voltages and current preventing assessment of fault type and location.
- The long time laps (seconds) between RTU scans did not allow close monitoring of fast (millisecond) switching operations such as breaker auto reclosing and sequence of breaker tripping (opening) in the lines connected through breaker-and-a-half schemes
- The reporting by exception created only fragmented view of system condition changes introducing a need to deploy state estimation rather than state measurement when trying to find the best match between power system models and measurements
- Time granularity provided with existing time-stamps at the SCADA database does not allow close temporal and spatial correlation (within tens of milliseconds) between events within and among substations

While the above mentioned data acquisition characteristics may look insignificant they actually had a strong impact on the EMS design properties and capabilities and profoundly affect EMS functional framework. This impact is illustrated in the following section where fundamental properties of the data acquisition system and its correlation with the power system monitoring capabilities are examined.

2.1.3 EMS Functional Framework

Based on the above observations of the data acquisition system design approach and mentioned performance constraints, some major EMS functional framework characteristics were established:

- Data scans could not accurately differentiate between various system switching states and phase unbalances, which resulted in the state estimator developed to monitor positive sequence values and topology processor introduced to try to differentiate between bad data caused by the measurement system vs the bad data perception caused by incorrect switching state (topology) detection
- Alarms used to differentiate between normal, alert and emergency states had to be individually traced without an ability to correlate them with protective relay operation, which created an "avalanche" of alarms created by major disturbances difficult to interpret at the time when operator had to have a clear indication of what was actually happening
- Time stamping at the SCADA database prevented an ability to correlate data at the source (substation) establishing a clear temporal and spatial relationship between measurements rendering an inability to use such measurements for direct state measurements or use of such data for model parameter estimation and verification

2.1.4 Conclusions

Consequences of the mismatch between legacy and new EMS design requirements affect data acquisition, data management and communication architecture. It is shown that the original EMS design view of the data acquisition system and its limitations in monitoring the system states comprehensively is the fundamental reason for redesigning the EMS system. The new opportunities for data acquisition system enhancements were pointed out.

3 Evolving EMS Design Path

To appreciate how the new EMS design requirements have emerged one has to follow the development path in several directions: what is the new technology capability, how the power system infrastructure and operation have changed, and why the EMS design approach needs to change in the future.

3.1 Technology Developments Affecting EMS Design

With the rapid advancement of technology, wide-spread substation deployment of Intelligent Electronic Devices (IEDs) comes into picture. These computer-based devices can record and store a huge amount of data (both operational and non-operational) with a sampling periodicity depending upon the intended purpose of the device. Their sampling rates are much higher than what is used in Remote Terminal Units (RTUs), and the data is sampled synchronously vs. being scanned in RTUs. In a modern integrated substation automation solution, various types of IEDs are interconnected for monitoring, control and protection purposes.

The Intelligent Electronic Devices (IEDs) that have been introduced in the last decade have increased the amount of field-recorded data dramatically. They fall into three categories in terms of their operating modes and measurement properties:

- Remote Terminal Units (RTUs) support SCADA systems by performing scanning of measurement points every few seconds. The earlier designs are typically reporting by exception and do not capture changes in the transient waveforms and fast-changing transitions in breaker contact statuses (auto reclosing sequences). The collection of data is not time-synchronized but rather scanned with analog measurements expressed typically as RMS values.
- Event Recording Devices (ERDs) such as Digital Protection Relays (DPRs), Digital Fault Recorders (DFRs), Sequence of Event Recorders (SERs), and Dynamic Disturbance Recorders (DDRs) are tracking (sampling) changes in the waveforms and/or contact statuses very closely once the recording is triggered by an event. Their sampling rates are in the order of kHz and the sampling is time-synchronized across all measurement channels
- Phasor Measurement Units (PMUs) are high precision IEDs that sample waveforms and contacts at high sampling rate (several kHz) and then compute phasors and also capture contact state. The sampling is time-synchronized via Global Positioning System (GPS) receivers, which allows time-correlation of measurements taken across large distances. The sampling is continuous and phasors are calculated and streamed to the final destination “continuously” at the rates between 30-240 measurements per second.

The first question that needs strategic answer is how the mentioned devices and related data may impact the EMS functionality and ability of the operators to better track the system operating states and make decisions. The answer is rather obvious: instead of using such data in different measurement infrastructures developed for different utility/groups and purposes, all such data should be integrated into one data management system. Initially, this may involve just a software solution but down the road as the SCADA and EMS design evolve, certain hardware changes should also take place. An example of how the integration may take place is given in Section 4.2.

The additional data from IEDs may not only improve existing EMS applications, but may also be utilized to implement new applications. The synchrophasor based Wide Area Monitoring, Protection and Control (WAMPAC) has been proposed to enhance system security in [12], and discussion about its implementation is elaborated in [13]. Automated fault location with improved accuracy, robustness and processing speed is proposed in [14], using both IED data and SCADA data. Condition-based maintenance of circuit breakers proposed in [15] took advantage of the trip coil data to improve maintenance efficiency and reduce forced-outages. These are just examples of the upcoming applications.

3.2 Issues in Today's Electricity Grid Operation

The expanding size of electric power systems and the increasing complexity in operation have brought up a challenge to detect and mitigate abnormal events. Cascading detection and mitigation is an application that tries to detect cascading events at an early stage and prevent them from developing into large-scaled blackouts [16]. In the meantime new additions to the grid are taking place. The distributed generation blurred the separation between the generation, transmission and distribution. Smart loads offered an opportunity to smooth out load curve by participating in Demand Side Management (DSM); some loads such as electrical vehicle can also act as a resource to support part of the grid when power supply is interrupted by faults. Intermittent renewables such as wind generator brought in complexity to operation and control along with clean energy requirements. High penetration and integration of renewables introduces variability and uncertainty in power system security and operational challenges. How the EMS evolves under such new developments in the electricity grid expansion remains an important design requirement.

3.3 Approach to New EMS Design

The new EMS design should be driven by the needs for data by different applications. It should consider the existing infrastructure, as well as the cost and time of re-furbishing and deploying new infrastructure. We envision the future EMS design approach evolving in three stages.

The aim of the first stage is to improve existing applications by providing new data. At this stage the software architecture of EMS remains the same while data from non-traditional sources are merged with SCADA data to provide improved performance of existing EMS functions. At the second stage new applications are implemented. The EMS measurement infrastructure is retrofitted with adequate data transfer and processing capabilities. Also, communication paths between applications and interfaces with "outside" functions are implemented as needed to achieve that. The third stage deals with designing a future EMS with no constraint from current situation, meaning a whole new design of infrastructure for an ideal, next generation EMS.

3.4 Conclusions

Integration of field data is the first step in the direction of improving the ability of operators to closely monitor power system operating states. Technological advancements in measurement devices necessitate both hardware and software changes in the new EMS design. The new EMS design should evolve to cater the needs of the current expansions of the power systems. A three stage design process is proposed which allows progressive improvements, and embracing all the new developments without significant design transition cost implications.

Due to a limited scope, this report is further focusing on enhancements in the existing design as a consequence of the data acquisition system technology improvements, which also affects the overall future EMS design paradigm changes.

The next section illustrates the possibilities for enhancing the existing EMS design using the intelligent alarm processor, topology processor and fault location accuracy improvements.

4 Enhancing The Existing Design

To study the requirement for improving today's EMS we selected three applications: alarm processing, fault analysis and state estimation. Improving such applications will result in closer tying physical systems and electricity markets, faster response to faults, and predictive assessment of system disturbances. The three functions have been identified to demonstrate improved performance of the mentioned applications: intelligent alarm processing [17], automated fault locating [18], network-topology processing [19].

4.1 Examples of the Improved Functions

4.1.1 The Intelligent Alarm Processor

Alarm processing is an important part of power system operation that has been a traditional feature of the power system energy management system (EMS) implemented over the past decades. Despite a variety of proposed solutions, operators still have a strong need for a better way to monitor the system than what is provided by the existing alarm processing software. An EPRI study [20] has listed issues that operators face with alarms during their day-to-day operation of a power system:

- alarms which are not descriptive enough;
- alarms which are too detailed;
- too many alarms during a system disturbance;
- false alarms;
- multiplicity of alarms for the same event;
- alarms changing too fast to be read on the display;
- Alarms not in priority order.

Operators are expected to monitor the system condition and take actions immediately after the alarms occur. However, when all problems mentioned above mix up, operators are severely constrained to perform efficiently in a timely manner.
An Intelligent Alarm Processor (IAP) model using fuzzy reasoning Petri nets (FRPN) was proposed in [17]. This intelligent alarm processor (IAP) model achieves the following goals:

- suppresses multiple alarms from one event;
- generates a single conclusion through a logical cause-effect relationship;
- automates the process to get answers quickly;
- makes graphical and numerical information concise and easy to follow.

The alarm processing application includes two stage analysis.
First Stage: The system's topology is analyzed based on circuit breaker status data from the real-time data base. The analysis includes all sections isolated by the opening of

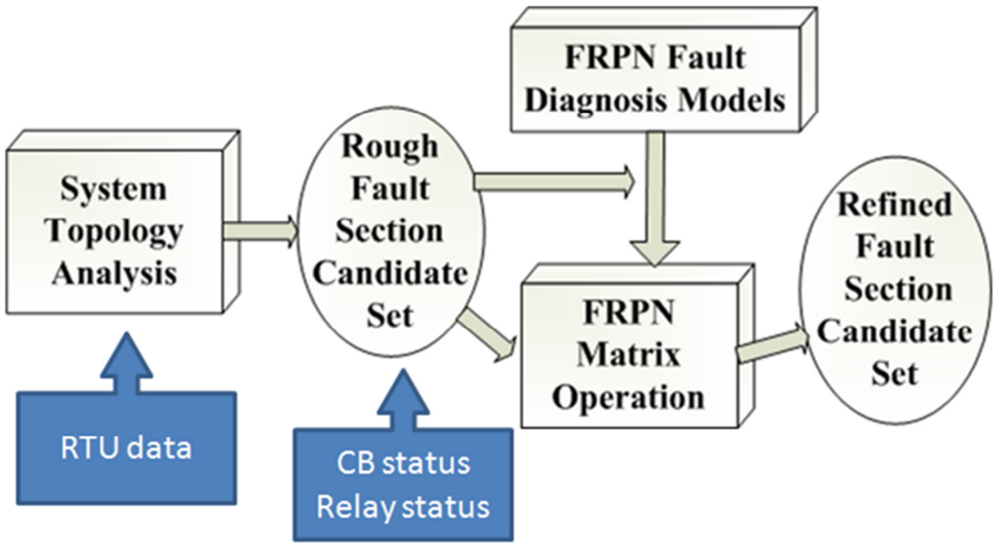


Figure 2 Intelligent alarm processor

circuit breakers into a rough candidate set. The set is rough because it may include sections which are not faulted but are isolated due to backup relay operation.
Second Stage: The FRPN diagnosis model as well as data in the real-time data base corresponding to each section in the rough candidate set is used and FRPN matrix operation is implemented.

When one or more faults occur on a given sections of the power system, protection devices will reach a certain status accordingly. The observed circuit breaker status signals obtained from RTUs of SCADA systems are used as inputs for estimation of the faulted sections. The logic reasoning method uses the relay status obtained from the online-database to validate each candidate fault section. The strategy is to build one FRPN diagnosis model for each section of the power system. Each model establishes reasoning starting from a set of SCADA data leading to the conclusion about fault occurrence on its section with a certain truth degree value.

The proposed approach introduces novel techniques for achieving efficiency and speed in alarm processing developed by using SCADA data and additional data obtained from substation intelligent electronic devices (IEDs). IED data refers to the status information from Circuit Breakers (CBs) and relays. Figure 2 is the block diagram of an IAP. The block titled “CB status and relay status” provides new data used for each of the next steps.

4.1.2 Automated Fault Location

The system-wide sparse measurement based fault location method [18] uses phasor measurements from different substations located in the region where the fault has occurred. The measurements may be sparse, i.e., they may come from only some of so many transmission line ends (substations) in the region. The technique compares measured data with data generated by the short circuit simulation of possible

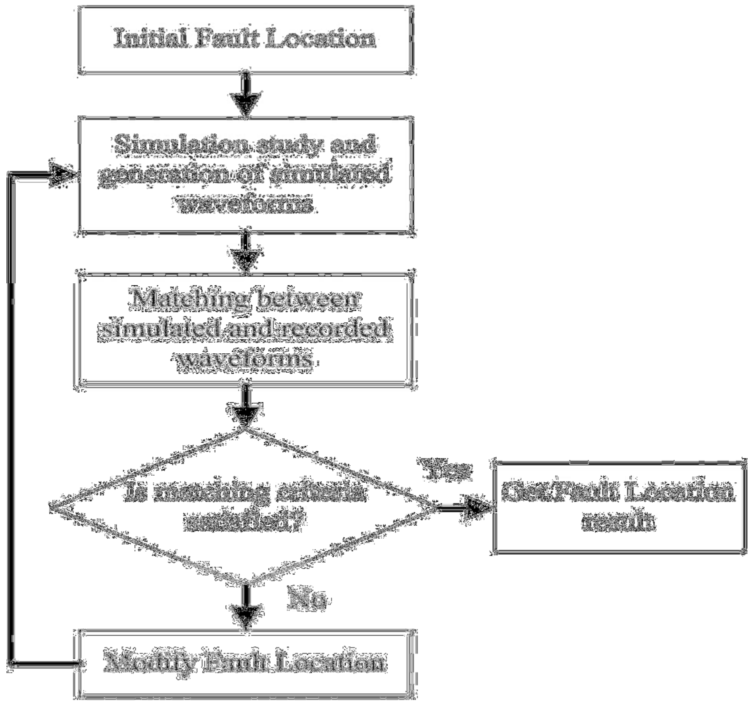


Figure 3 Flowchart of system automated fault location method.

fault locations. The measured and simulated data from the locations where measurements are taken is compared while the location of the fault is changed in the short circuit program. This process is repeated automatically until the measured and simulated values have minimal difference, which indicates that the fault location used in the short circuit program is the actual one in the field. The overall process is described in Figure 3.

The waveforms can be matched using phasors or transients. In [18], field-recorded waveforms are used to calculate phasors, and they are in turn matched with the phasors obtained using short circuit study from short circuit model data. A cost function defined using the simulated and recorded phasors is minimized to match the simulated and recorded waveforms. The minimization is carried out using genetic algorithms. The architecture of the fault location scheme is shown in Figure 4. The input data include the DFR data, the interpretation file for DFR data, the system model file in the PSS/E format and the PI Historian data matched to the model. The detailed description of this data requirement and handling of the data to extract information was discussed in earlier sections. The operation procedure of the software to utilize such information to obtain fault location is briefly described below.

The fault location solution using GA is performed in the following steps. First, the initial population is chosen randomly. A fault location variable can be chosen from a range of zero to the length of the possible faulty line, and a fault resistance variable can be selected from typical possible fault resistance values. Second, short circuit studies are carried out using PSS/E, and the fitness is evaluated for each of the possible fault locations. Third, by using three GA operators (selection, crossover, and mutation), fault posing for the next iteration is obtained. By iteratively posing faults, running short circuit

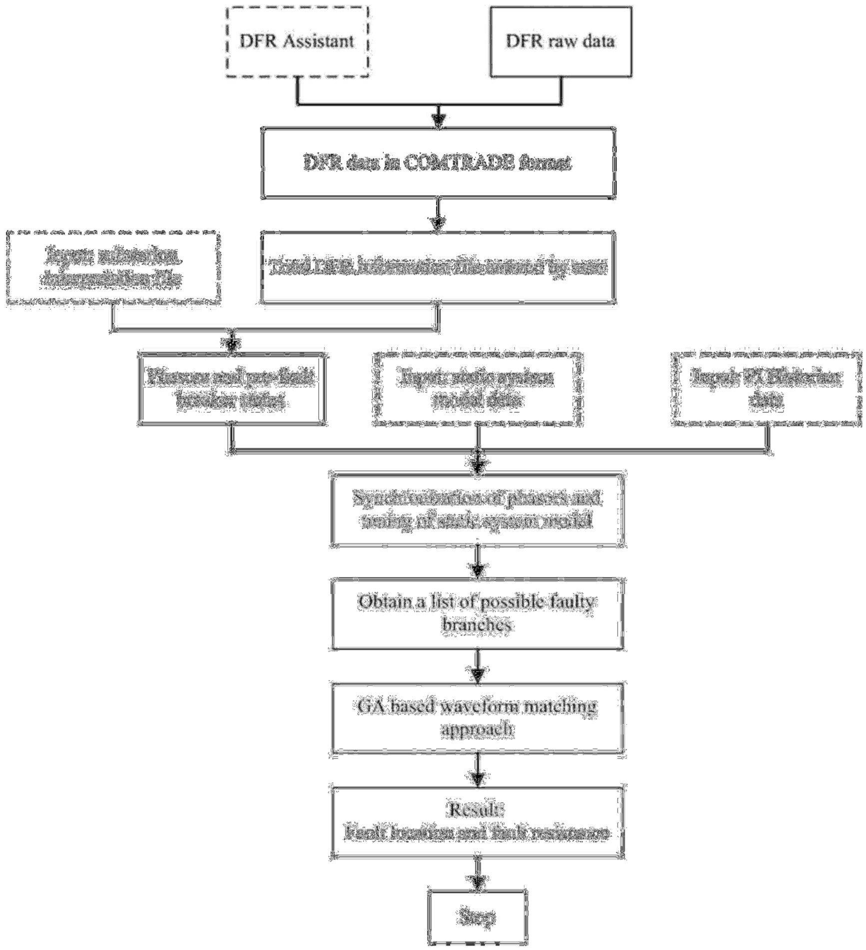


Figure 4 Architecture of the fault location scheme

simulations, evaluating the fitness value, updating the fault location and resistance, the GA-based search engine guides the search process for a globally optimal solution.

4.1.3 Network-Topology Processing

Network Topology Processor (NTP) is an important function in State Estimation (SE), It determines the status of Circuit Breakers (CB) in real-time to obtain network topology. Traditionally NTP takes CB status data (on/off) to merge electrical nodes that are connected by closed CBs into a bus, and assign nodal injection devices and branches to the proper locations in the bus-branch model. Analog measurement data are used to determine the electrical quantities (voltage and current) directly (bus voltage magnitude measurements, bus power flow injection measurements, branch power flow measurements) or indirectly (nodal voltage magnitude measurements, nodal power flow injection measurements, CB power flow measurements, etc.). The Dynamic Utilization of Substation Measurements (DUSM) from [19] is a method that utilizes currently available measurements in substations to recover network observability to make up for loss of measurements due to topology change. Additional and redundant data from multiple IEDs can be used to improve robustness of topology determination.

IEDs of interest for this application are Digital Fault Recorders (DFRs), Digital Protective Relays (DPRs), and Circuit Breaker Monitors (CBMs). Those IEDs provide multiple measurements of the same values. All the mentioned IEDs measure:

- Phase currents,
- Circuit breaker auxiliary contacts "a" and "b",
- Relay trip signal.

Such redundant data may be utilized to verify accuracy of the measurements. The additional signals recorded by IEDs are:

- Internal circuit breaker control signals, recorded by CBM, providing additional insight into CB operation
- Transients, recorded by DFR, describing behavior of phase current under switching and fault clearing events
- Internal protective relay logic signals, captured by DPR, explaining details of the initial relay action as well as the follow up trip/close, auto-reclosing and breaker failure actions of the breaker

If data recorded by the mentioned IEDs were stored in a substation database, improved robust topology determination can be obtained using additional and redundant data through the following analysis [19]:

- *Time correlation between analog and contact data*. It is well known that a change in topology is followed by a change in the analog signals "seen" at different points in the network. Digital Fault Recorders (DFRs) are capable of tracking both analog (voltages and currents) and contact (status) information from circuit breakers. By combining this information and drawing the cause–effect conclusions one can confirm whether a breaker has opened/closed by monitoring the expected changes in the associated analog signals.
- *Functional correlation*. Associating the recorded signals with the specific action that the relay was engaged in can yield additional information about the circuit breaker status. Digital Protective Relays record both input signals (currents and_ voltages) as well as automatic control actions on the breaker. Monitoring the sequence of such signals gives the actual final open/close positions of the breaker, and hence allows one to check the actual outcome of the CB status against an expected one.
- *Switching sequence check*. Many switching actions are initiated by commands that cause a change in control circuitry contacts of the switching or control equipment. By using data captured by Circuit Breaker Monitors (CBMs) one can verify if the initiated switching sequence has been completed as expected since the deviation in the expected sequence can easily be observed by looking at a possible deviation in the CB control circuit signals.

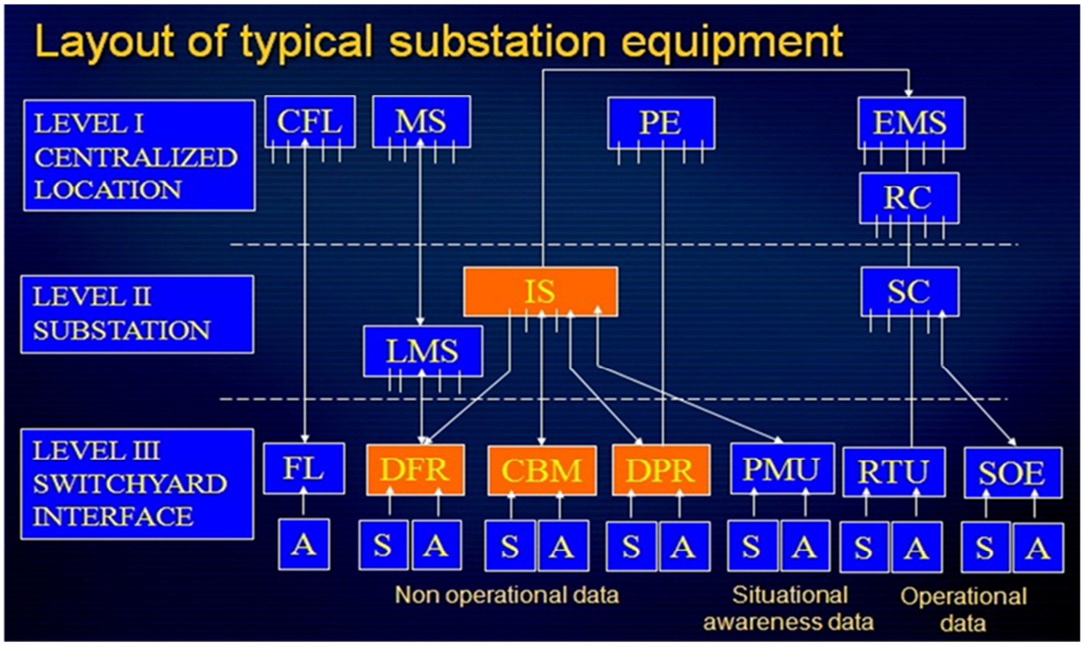


Figure 5 Layout of IED infrastructure

4.2 Integration of IED Database and SCADA Database

Implementation of the proposed functions requires both traditional operational SCADA data and non-operational IED data. Figure 5 illustrates the different measurement infrastructures established for calculating fault location using Fault Locators (FL), recording events using Digital Fault Recorders (DFRs), Digital Protective Relays (DPRs), Circuit Breaker Monitors (CBRs), Sequence of Event Recorders (SOEs), and Remote Terminal Units (RTUs) of SCADA, and tracking voltage and current phasors using Phasor Measurement Units (PMUs).

The basic idea of integration of data shown in Figure 6 is to collect all the IED data in a substation database and use it for extracting information automatically.
The data integration and information exchange concept represented in Figure 6 raises a number of practical issues that need to be resolved for the proposed concept to be readily implementable:

- Data from different types of substation IEDs has different data properties resulting from different A/D conversion approaches such as waveform sampling rates, approaches to sampling synchronization, accuracy and time resolution
- Some of the IED data is scanned at fixed time intervals (RTU), some is captured when an event occurs (DRFs and DPRs) and some is continuously streamed (PMUs)
- Approach to controlling time correlation and time stamping is also quite different with all SCADA data being time stamped at the SCADA database while the data from IEDs other than RTUs being time-stamped at the source but time correlated differently

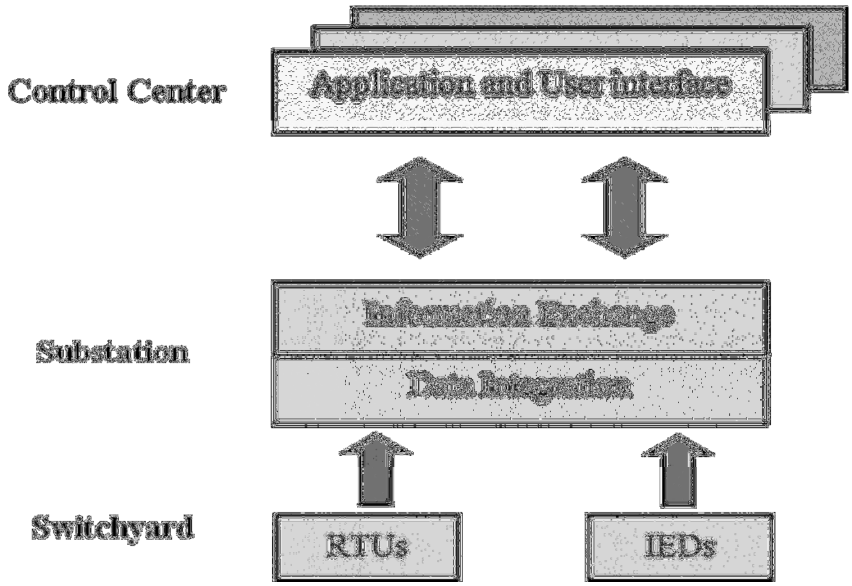


Figure 6 Integrated data

4.3 Semantics for IED and SCADA Database Integration

Figure 7 shows the architecture of data integration across the substation and centralized locations used for operating and maintaining the power system.

One big issue is how to convert data provided in different formats into the one that the new applications can use. One requirement is the consistent semantic modeling of IED data. IEC61970 is a standard for integrating number of complex applications developed by different vendors in the same semantic framework using Common Information Model (CIM) to represent the SCADA data [21]. The CIM approach mainly focuses on modeling operational data and corresponding substation components. It is object oriented and -extensions are possible. Practice shows that the published (CIM) version cannot meet the requirements of some important field device representations for real time applications such as Fault Location (FL). CBM, DFR and some other IEDs that may introduce new functionalities that do not have CIM representation. Extension of CIM such as currently done for PMUs is needed.

While IEC61970 provides a detailed description of connectivity between various equipment, substations and their static and dynamic information, IEC61850 has the most detailed description of substation equipment and its monitoring and control aspects [22]. IEC61850 defines a tree of objects for modeling IEDs, starting from the server object (representing physical IEDs), and containing a hierarchy of Logical Devices (LDs), Logical Nodes (LNs) ad Data Objects (DOs). The issue of missing IED Model in CIM can be resolved through harmonization of CIM and IEC61850 [23]. Current standardization efforts are under way to allow straight forward implementation of the harmonization between 61850 and 61970.

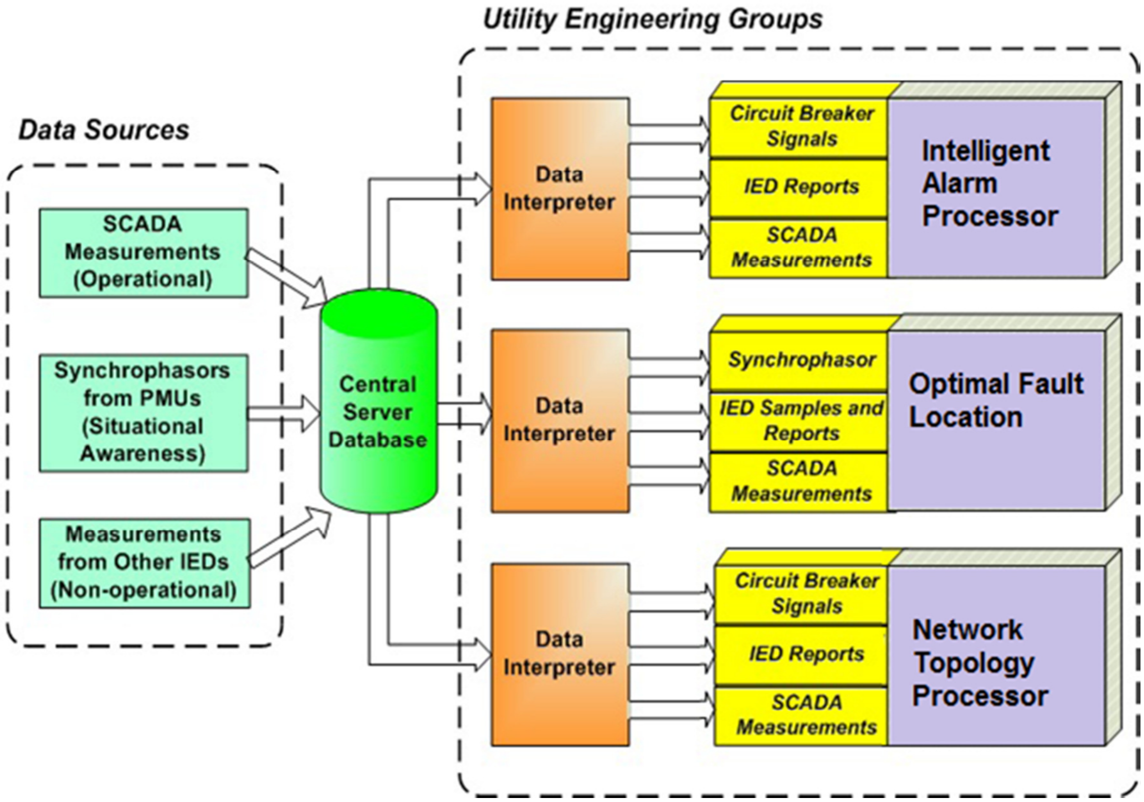


Figure 7 Architecture for data collection and conversion

4.4 Conclusions

The ability of operators to closely monitor power system operating states can be improved by field data integration. This section illustrates that such improvements can be gained in the areas of intelligent alarm processing, automatic fault location and topology processing. Integration of IED data base and SCADA data base is the key step for improving operational visibility of the system. Consistent semantics modelling is essential for seamless integration of IED and SCADA databases.

Synchronizing all data sources using common time-synchronization framework is very important. A comprehensive approach to the time-synchronization issues has to be coordinated with the need to differentiate the spatial properties of data. Such issues are discussed in the next section where future EMS design is presented.

5 Future EMS Design Requirements

This section points to some key elements of the future EMS design, namely the temporal and spatial correlations, as well as new communication opportunities.

5.1 Temporal Considerations

5.1.1 Relative and Absolute Time as A Reference for Correlating Power System Events

Monitoring, control, and protection applications require knowledge of the instance of time when a given event has occurred. The relative time may be used to understand the time sequence between the various control actions. As an example, knowing the inception time of a fault, the time it takes relays and breakers to operate can be calculated relative to the event incident time. Besides, an absolute time plays a role when various data related to a given disturbance is collected at multiple locations and such data is used to improve knowledge about the event. As an example, operation of multiple relays and tripping of multiple breakers may be sensed by IEDs located in multiple substations, so absolute time needs to be known to be able to differentiate actions corresponding to the same event from actions caused by other but time-adjacent events.

5.1.2 Sampling Clock Time as A Reference for Synchronous Signal Sampling Vs. Scanning

Various measurements in the power system are performed by IEDs, which convert the measurements to samples by performing analog-to-digital (A/D) conversion at the time the measurement is taken. The samples are taken by a sample and hold (S/H) circuit, and then the A/D converter converts samples into a computer word, known as data. The clock signal used for initiating the S/H circuit operation can be applied simultaneously (synchronously) for all the measured channels or sequentially as each channel is sampled/measured (scanned). Recovery of the information from data samples depends heavily on whether the signals were sampled synchronously or scanned. For example, it is possible to recover the phase angle between different phases in a three phase circuit if synchronous sampling was performed, but it may not be possible to recover it if the signals in the three phases were scanned. The mode of sampling clock control that results in synchronous sampling vs. scanning is widely different in modern IEDs vs. legacy Remote Terminal Units of Supervisory Control and Data Acquisition (SCADA) system.

5.1.3 Time as A Reference for Waveform Representation in Time and Frequency Domain

Many of the applications for monitoring, control, and protection require that the analog waveforms of current and/or voltage be analyzed either as time-domain functions or phasors. The time domain representation is important when waveforms experience transient behavior (during faults) while the phasor representation is sufficient for steady state conditions (during normal operating conditions). In both instances, how the time is represented is important, which leads to either an accurate representation of a waveform at any instant in time or an approximation of the waveform with a phasor at a given time.

Typical example of time synchronization between waveform samples is two-ended protection or fault location on transmission line which is implemented using time-domain solutions. A typical example of synchronization of phasor samples is in the two-ended fault location where the measurements from two ends are phasors but may be used either as synchronized or unsynchronized. While the phasors extracted from sample may be used for many applications, taking phasor samples synchronously across all the IEDs is more involved since it requires understanding of how the sample calculation is performed.

5.1.4 Implementation of The Time Reference

To illustrate how various options of time synchronization mentioned above may be implemented, Figure 8 shows various designs of the sample and hold and A/D/ conversion circuits used in legacy and new IED solutions. For ease of implementation of the smart grid solutions in general and in particular the ones discussed in this report, the sampling synchronization should be controlled by a common reference such as a GPS time synchronization signal [23]. GPS receivers typically provide both the sampling clock signal and absolute time reference as shown in Figure 8, which may be then combined with the design shown in Figure 9 to provide very precise control of all the temporal issues mentioned in this section.

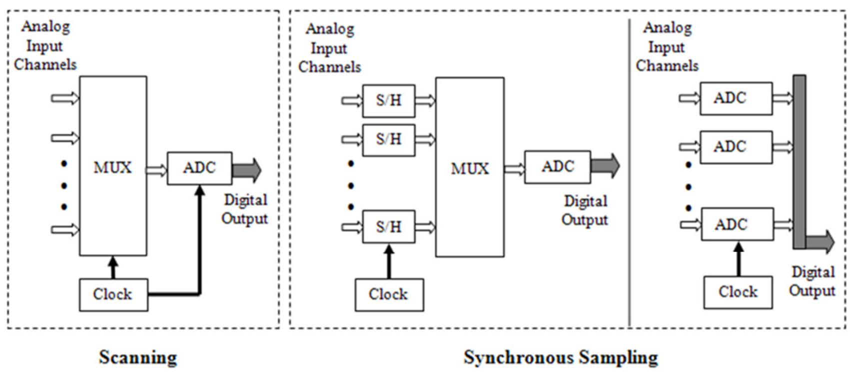


Figure 8 Synchronous sampling vs. scanning

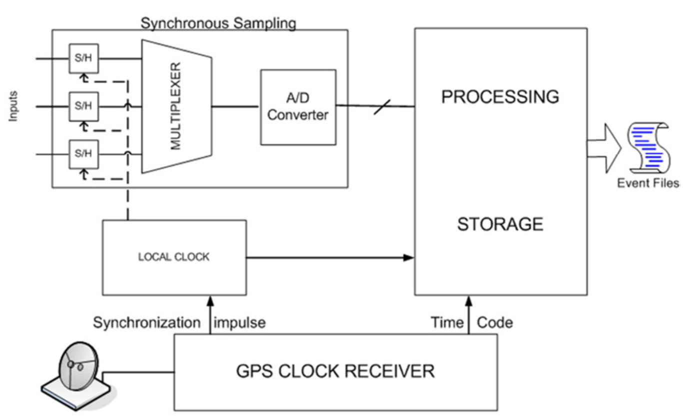


Figure 9 GPS synchronization

5.2 Spatial Considerations

5.2.1 Location as A Reference for Data Processing and Information Extraction

For various events in power system such as faults only specific power system components are involved in the event and only local data from IEDs are used in the process of information extraction. For example, transmission line protection relay uses only local data to analyze faults on the line. On the other hand, System Integrity Protection Scheme (SIPS) monitors large area and requires wide-area data. Due to huge diversity in IEDs, their technologies and communication infrastructure it is challenging sometimes to achieve good spatial considerations. There are some innovative ways that could be used to improve presentation of spatial data obtained by substation IEDs: precise satellite images similar to Google Earth [24], National lightning Detection Network (NLDN) [25], and Geographic Information System (GIS) technology [26].

5.2.2 Location as A Reference for Model Representation

In the approach to create new knowledge the extracted information needs to be supplemented by a predefined model. Choices of models vary depending which type of information is utilized to create them. As an example, the model can represent power system network, like in case with the Optimal Fault Location applications [18], or it can represent cause-effect relationship in control equipment operations like in the case of Petri-Net logic used in Intelligent Alarm Processor [17], or it can represent pattern space for resulting vectors in the Neural Network based Fault Detection [3].

5.2.3 Location as A Reference for Applications

Given that there may not be a clear divide between the applications at a substation and the applications at a central EMS, an application may reside at either the control center or a substation or even be split between the two. For example, those applications that are specifically meant for the human operator (monitoring, alarming, supervisory control, etc.) must be resident at the control center where the operator consoles are. Similarly, those applications like local control and protection will be resident at the substation. The wide-area control and protection that requires data from several substations can be resident on any computer to which communication of this data is possible. Similarly, some applications can now be distributed between several substations and/or the central EMS given that each substation will have significant computational capability to do a lot of pre-processing before sending information to the EMS (e.g. a lot of the topology and state estimation calculation can be done at the local substation before sending to the control center [27], [28].

5.3 Challenge to Communications

The biggest issue for communication is how to handle the huge amount of data.

- Bandwidth: Most of the communications networks being deployed today are based on lower-bandwidth, lower-cost technologies. As new data is being collected and transferred to control center, extra bandwidth is needed to accommodate the large volume of IED data. For example bandwidth over

100Mbyte/sec is most likely to be the lower boundary with the upper boundary reaching 1Gbyte/sec.

- Latency: As some of the selected applications are implemented to support system control and operation, latency becomes the most important issue in the data transfer, which is decided by the transfer rate and the number of switches the data transverses. The most stringent requirement for the latency comes from the cascading event detection where the local substation data such as fault location may have to be transferred to the control center and an automatic command issued within a few seconds.

- Data compression: It is a solution to improve the efficiency of data flow and hence reduce latency. For the events that do not show much change in the waveforms or measurements lossy or lossless compression may be performed. Data compression may be used to facilitate timely transfer of information.

- Congestion management: It is another solution to reduce latency under the condition of heavy traffic. Data classification and prioritized communication channel are the key issue in congestion management since special high priority data transfer may be implemented for emergency situations.

Figure 10 shows a generic communication infrastructure that connects all substations in an information network [29]. The communication infrastructure is shown as a three-level hierarchy. Each substation has its own high speed local area network (LAN) which ties all the measurements and local applications together. Each substation also has a server that connects to the higher level communication network through a router. A LAN within control center receives data and sends it to different applications (after pre-processing, if necessary). Thus all applications requiring data from more than one substation, i.e., applications that are not local, have to use this higher level network for gathering input and sending output.

The main requirement for the communication system that will serve the future EMS is its ability to transmit the right data from the location where it is produced to the location where an application needs it. The data can be the measurements at a substation or processed data at some server. Different sets of data are needed by different applications at different time scales. The communication middleware must be able to handle this data transmission with a high level of quality of service (QoS). This kind of a publisher-subscriber communication system with the ability to monitor proper QoS is described in [28], [30], [31].

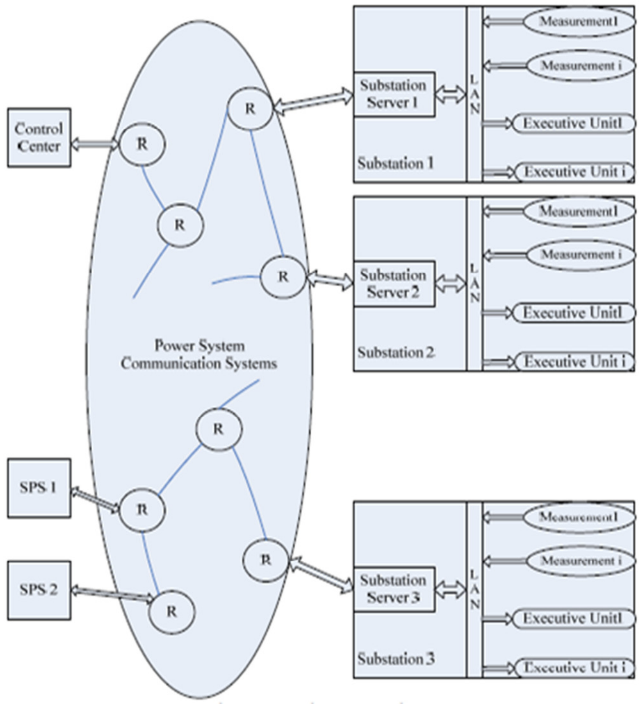


Figure 10 Real-time information infrastructure

5.4 Conclusions

The future EMS design requirements should consider the temporal and spatial attributes of IED data sources. This section highlighted the important temporal considerations which require special hardware implementations. Spatial considerations are shown to be very important for information exchange, models representation and applications. The huge volumes of data generated pose several challenges to the communication architecture. The future EMS communication architecture needs to cater all applications as and when needed with high reliability. The following section essentially describes in-detail some of the communication challenges mentioned and proposes new solutions.

6 Design of Communication Architecture

As the smart grid is operated closer to the margins it becomes imperative to collect fast sub-second measurements to gain insights about the dynamic behavior of the grid and to take necessary control actions for reliable operation of the system [32]. With the availability of phasor measurement units (PMUs), synchronized measurement of voltage and current phasors can be taken at rates of about 30 to 120 samples per second. Most of the smart grid applications have a strict latency requirement in the range of 100 milliseconds to 5 seconds [10], [33]. To feed these new applications a fast communication infrastructure is needed which can handle a huge amount of data movement and can provide near real-time data delivery. In such a scenario it is evident that after a certain point, the notion of centralized operation and control will no longer be scalable. In the place of traditional one directional point to point communication links, the communication infrastructure needs to be upgraded to network of communicating nodes supported by a flexible middleware with high bandwidth and application specific quality of service (QoS) capabilities.

Moreover, with the advances made in ubiquitous computing systems, the notion of distributed data and distributed analytics becomes amenable. The question then becomes - what should be the design of the new communications architecture? Given that the data and computations are going to be distributed, what data should reside where? How data is to be moved to the applications efficiently meeting the latency requirements? This report attempts to answer these questions by presenting a possible design of communications architecture for wide area control and protection of the smart grid.

6.1 Survey of Power System Applications and Latency Requirements

The network topology and its real-time operating state are required for successful analysis, operation and control of the grid. The topology defines the interconnection of the grid and is almost constant over time [29]. On the other hand, the state (voltage and angle at all buses) of the power system changes dynamically over time due to changes in loads, generation and switching operations. Without phasor measurement units, state of the grid is derived from voltage magnitude (V), real power (P) and reactive power (Q) measurements using a computer program called State Estimator (SE). Most of the smart grid applications based on this set-up are bottlenecked by the latency and accuracy of the estimated state of the system as calculated by state estimator. As these measurements are collected by Supervisory Control and Data Acquisition (SCADA) system by polling over 2-4 seconds, the measurements do not represent a snapshot of the actual system state at one particular time. This set-up seems to work fine for an unstressed grid working in almost steady state conditions. The present operation of the grid is often very close to its security margins and the system ventures into the emergency state more frequently than before. State-estimator cannot capture the changing state of the system and sometimes fails to converge. With PMUs all over the system, the state of the grid (voltage phasors) can be directly measured and moreover can be measured many times per second with time-stamps giving insight into the dynamics of the system.

A number of smart grid applications have already been developed and some are in the process of development [34]. To understand their communication needs, a brief survey of some of the most important applications [35] in terms of their data requirement and latency is presented in Section 6.1.1 and Table 6.1. A communication network designed to handle these basic applications would be able to handle other applications as well.

6.1.1 Classification of Applications

(1) State Estimation:
Even though voltage phasors across the grid can be directly measured with PMUs everywhere, state estimation is an essential tool to eliminate effect of bad measurements on the final calculation of the state. Most of the Energy Management System (EMS) applications are fed from state estimated data and are benefited by faster, accurate and synchronized measurements. Also with PMUs, two level state estimators [36] can be designed to run locally within the substation to feed applications like transient stability.

(2) Transient Stability:
Transient stability is a concept related to the speed and internal angles of the generators. A typical system can get transiently unstable in approximately 10 cycles. The way to prevent this is to island the system in coherent groups or shed load/generation using Special Protection Schemes (SPS). The wide-area control to do so is still not in place because of latency requirements and it would to be a big challenge to design such a control system even in the future.

(3) Small Signal Stability:
To solve small signal stability problem, signals only at selected key locations are needed where modes are more visible. For any of these modes, if damping happens to change then it changes slowly over time. Moreover, if the damping is negative, even in that case, oscillations take time to build. So small signal instability occurs over a period of time and by observing the mode damping near real time, this can be prevented by resetting the power flows across the lines or by setting Power System Stabilizer (PSS) online.

(4) Voltage Stability:
Voltage instability spreads over time starting from reactive power (VAR) deficient area and can ultimately cascade and lead to a blackout. The problem can be solved if the voltage in an area can be measured and corrected by balancing VAR in the particular area or by islanding the area.

(5) Post-Mortem Analysis:
This will be a key application to correct power system models and to update engineering settings for the system. The engineering settings are bound to change as the system changes. This application does not need to run real time and has no latency requirements. This application will require PMU data as well as data from other IEDs (Intelligent Electronic Devices) like DFRs (Digital Fault Recorders). From the Table 6.1, it is observed that the different applications have different latency requirements. Applications related to transient stability require the delay between collection of measurement and receiving of signal at the control equipment to be less than 100 msec. The communication

Table 6.1 Survey of smart grid applications based on latency and data requirements

Main Application	Applications based on it	Origin of Data/Place where the data needed	Data	Latency requirement	Number of PMUs we may need to optimally run the application	Data time window
Transient Stability	Load trip, Generation trip, Islanding	Generating substations/ Application servers	Generator internal angle, df/dt, f	100 milliseconds	Number of generation buses (1/20 buses)	10-50 cycles
State Estimation	Contingency analysis, Power flow, AGC, AVC, Energy markets, Dynamic/ Voltage security assessment	All substations/ Control center	P,Q, V, theta, I	1 second	Number of buses in the system	Instant
Small Signal Stability	Modes, Modes shape, Damping, Online update of PSS, Decreasing tie-line flows	Some key locations/ Application server	V phasor	1 second	1/10 buses	Minutes
Voltage Stability	Capacitor switching, Load shedding, Islanding	Some key location/ Application server	V phasor	1-5 seconds	1/10 buses	Minutes
Postmortem analysis	Model validation, Engineering settings for future	All PMU and DFR data/ Historian. This data base can be distributed to avoid network congestion	All measurements	NA	Number of buses in the system	Instant and Event files from DFRs

network should be built to meet this requirement. In the next section, the architectural considerations for such a network are outlined, followed by description of a centralized and distributed architectures.

6.2 Design of Communication Architecture

6.2.1 Architectural Considerations

This section discusses the architectural considerations to meet the communication requirements of the applications mentioned in Table 6.1.

6.2.1.1 Location of Data

In order to minimize the data traffic on the communication network, the choice of data that is put on the network will have to be determined by the application which will consume that data. Although the PMUs can sample the phasors at a rate of 30 to 120 samples per second, every application may not require data at such high rates. Hence each substation stores the data measured at that location in a local database and makes this data available. The approach here is to keep the data distributed and close to the power network components from which the data is measured.

6.2.1.2 Location of Applications

It can be observed from the latency requirements listed in, that only the class of applications concerned with transient stability of the system needs faster data with higher detail. Other applications are relatively less stringent in the need for real time data. This offers lot of flexibility in the location of applications.

6.2.1.3 Movement of Data

Since the data and applications are defined to be distributed a communication infrastructure is needed which can identify a specific subset of data and transfer to the required application. The characteristics of such an infrastructure are described in [32]. A middleware system forms the heart of such an infrastructure, which can perform the functions of efficient routing of data packets while conforming to the quality of service (QoS) constraints. An architectural paradigm known as publish/subscribe is suitable for such a middleware. The sources of data need not be aware of the consumer of data. The sources simply publish their data to the middleware. The applications which require specific data will subscribe to the middleware. A list of all received subscriptions is maintained by the middleware. When the data is published the middleware notifies the receiving application and forwards the data.

6.2.1.4 Format for Data and Control Commands

The PMUs are being manufactured by multiple vendors and interoperability among equipment from different vendors is ensured by using standard formats. The standard C37.118 is used in practice for communication of PMU data [37]. Among the four frames that are defined in C37.118, the data frame is one that is sent out from the substation under normal conditions. The command frame defined in C37.118 can be used to send commands to the PMUs for controlling the associated power system equipment.

6.2.1.5 Management of the Middleware

While the system becomes increasingly distributed an effective means of configuring the flows on the communication infrastructure is needed. In order to achieve this, the middleware should provide an interface which can be used to manage and configure the subscriptions from various applications. One of the major responsibilities of the middleware is to deliver the QoS requirements. These functions are achieved by middleware by separating the data plane and management plane. As an example, the functionality of GridStat [31] is shown in Figure 11.

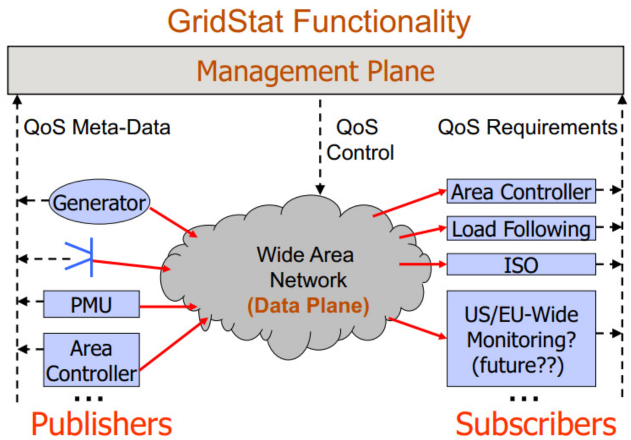


Figure 11 Basic middleware functionality of GridStat

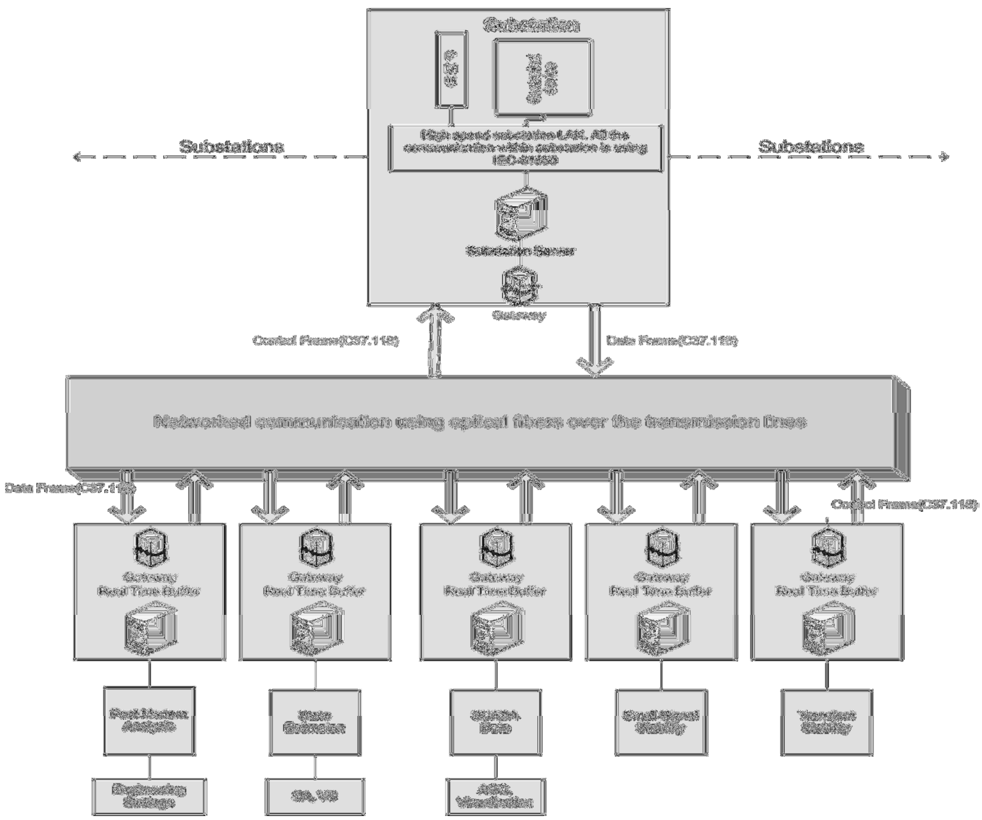


Figure 12 Centralized communication architecture

6.2.2 Centralized Communication Architecture

Smart grid of the future is assumed to have PMU data available across the grid. To meet the latency requirements and to handle the huge amounts of data, a real time information infrastructure was proposed [32]. Because of the huge amount of data generated at each substation, not all the data can be sent to one central location. Therefore, there is a need for the application servers to be distributed as shown in Figure 12. Separating out application servers will also help to tag packets for latency purpose. The middleware system to handle this distributed data base and to provide the latency and other Quality of Service (QoS) is one of the major goals of the NASPI [34] and some research initiatives like Gridstat [28], [30].

The data latency is defined as the time between when the state occurred and when it was acted upon by an application. Each application has its own latency requirements depending upon the kind of system response it is dealing with. Among the other delays [35], communication delay also adds to the latency and needs to be minimized. The communication delays on the network are comprised of transmission delays, propagation delays, processing delays, and queuing delays [32]. Each of these delays must be looked into to understand the complete behavior of the communication network for a given network.

The data from various PMUs from a substation is sent out in C37.118 format Data frame. This data is then received at the location of the application in its respective Phasor Data Concentrator (PDC) usually using proprietary software; the only open source software called Open-PDC is used in this work.

PMUs constantly send out the data frame on the network. For many of the smart grid applications latency is an important consideration in designing a communication infrastructure. Keeping this in mind, User Datagram Protocol (UDP) becomes a preferred protocol at the transportation level over Transportation Control Protocol (TCP). At the application layer, Constant Bit Rate (CBR) is a good choice to carry the continuously generated data frames of PMU. Maximum Transmission Unit (MTU) size of the link layer will play an important role as OpenPDC is designed to receive a complete C37.118 packet and not a broken one. As shown in the simulations, packet size can be around 1500 bytes, i.e. Ethernet communication having MTU size as 1500 bytes is the obvious choice. Given the latency and bandwidth requirements, optical fibers and Broadband over Power Line (BPL) are the promising solutions. For uniformity it is assumed that optical fiber is present throughout the network. Hence the protocol stack will look like as shown in Table 6.2.

6.2.3 Distributed Communication Architecture

Based on the considerations discussed in Section 6.1.1 it can be inferred that some of the applications needing lower latency should be decentralized. As a consequence of this

Table 6.2 Protocol layers for communication in one control area

Layer	Protocol
Application	CBR
Transportation	UDP
Network	IP
Data	Ethernet
Link	Ethernet (Optical fiber)

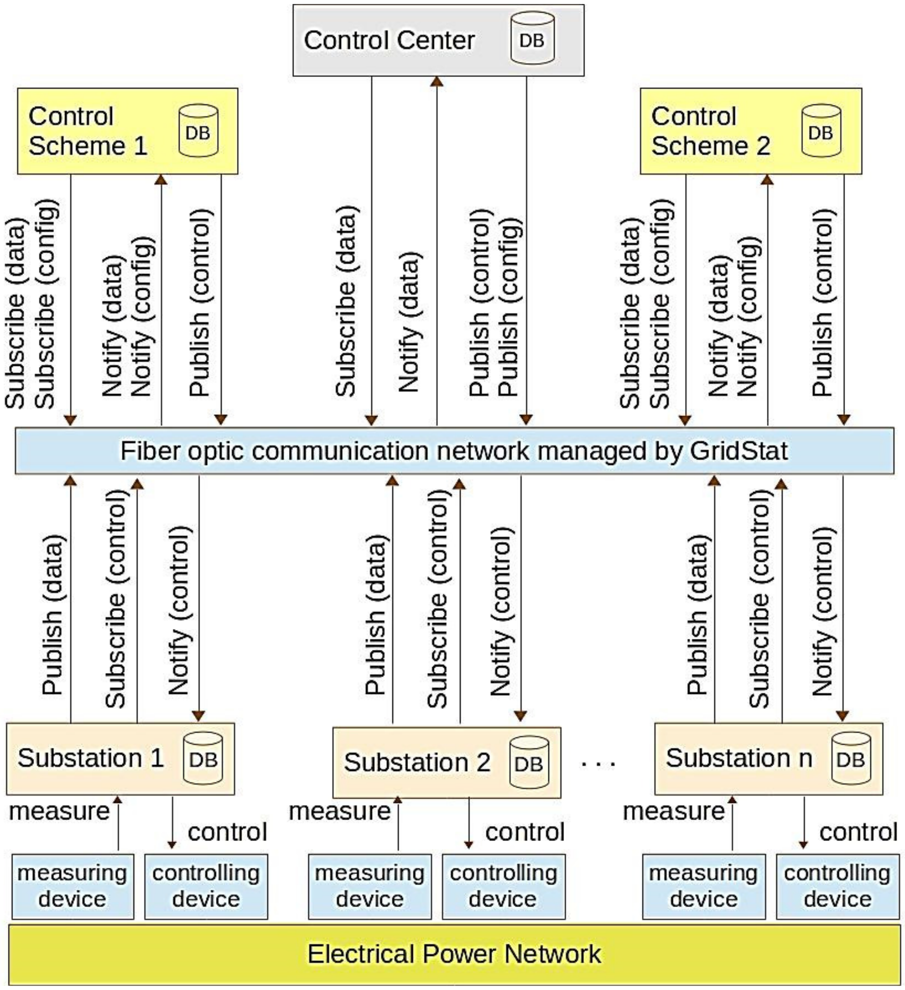


Figure 13 Distributed communications architecture for power system control

decentralized or distributed approach a need arises for storing the data at various levels. Since, only a subset of data is communicated as per the requirement of the applications, effective data management strategies are needed to define the movement of the data across the various nodes of the network. To address this need, an information architecture for power system operation based on distributed controls using a publish/subscribe communication scheme and distributed databases is described in Figure 13.

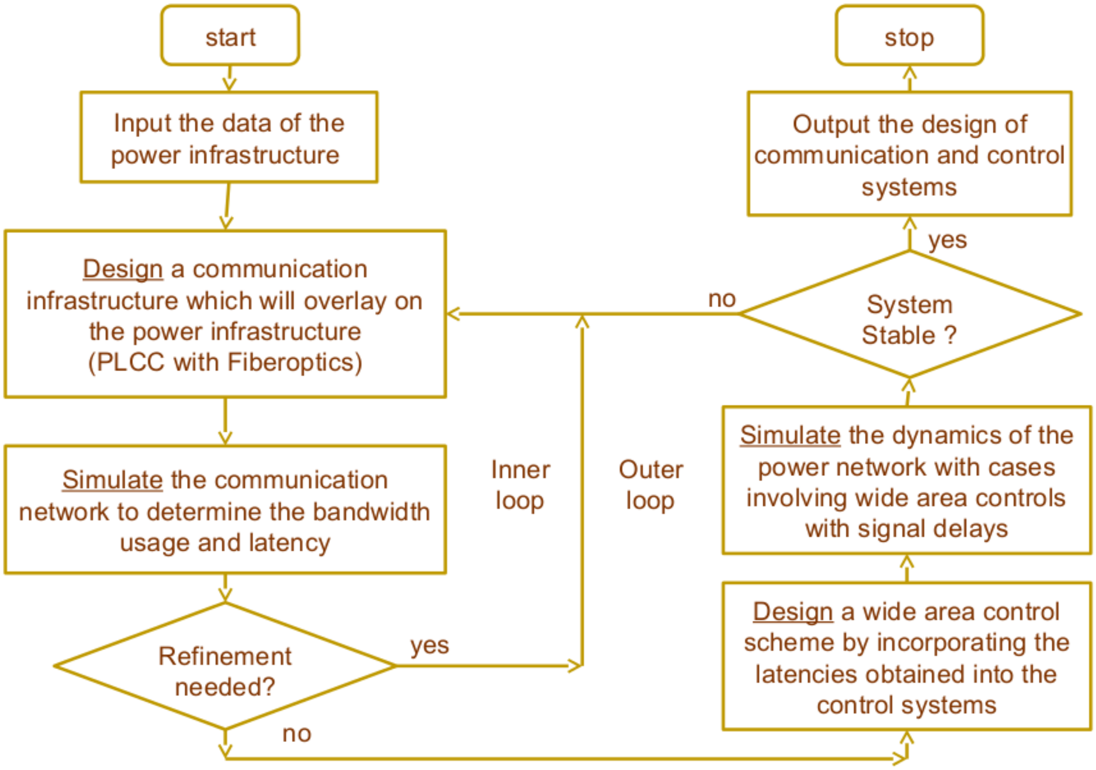


Figure 14 Process for design of communication architecture

The key feature of the proposed architecture is that the databases are distributed at each level. Each substation stores the measured data locally. Applications that need real-time data for transient stability monitoring and control are not located in the control center but can be located on a computing node near the substations, identified as "control schemes" in Figure 13. The special protection schemes (SPS) being used in power systems are one example for such control schemes. At this level the data can also be stored for future use in computations. The data and control frames, as described by the C37.118 standard, can be exchanged via publish/subscribe based middleware which manages the fiber optic communication network. The communication network can be physically laid along with the power system network. The control center has its own set of applications and associated databases. While the focus is on optimizing the latency of time critical data, the data which is non-time critical can also be moved around with appropriate QoS attributes using the same communication network. The objective is to achieve a configuration of communication network which is most efficient and compatible with the operation of power system network in a decentralized way.

6.2.4 Process for Design of Communication Architecture

The flow chart of Figure 14 describes the process for design of communication architecture for a large power system. The left hand part of the flow chart contains the inner loop of the process, in which the communication network is designed and simulated. The output of this inner loop is the bandwidth and latency values that would occur for the designed communication network topology. These values then form the inputs to the outer loop, which involves the simulation of the power system network to determine the wide area control system. If such a suitable control system is not feasible as allowed by the designed bandwidth, the process can go back again to the inner loop and strengthen the communication network. This process can be repeated until a suitable overall solution for control is achieved.

Having discussed the process for design of communication architecture, the discussion now proceed towards simulation of communication network under various scenarios in section 6.3. Essentially the detailed method of running inner loop of Figure 14 is presented in section 6.3 followed by the outer loop in section 6.4.

6.3 Simulation of Communication Networks

6.3.1 Simulation Setup

The simulation results for Western Electricity Coordinating Council (WECC) 225 bus system and Poland 2383 bus system [38] are presented here. Some of these results are already included in [32], [38] and they are listed here for completeness.

One of the possible communication scenarios is simulated using an event based, open source communication network simulator called NS2 version 2.34 [39], [40]. Further Matlab, Python, Tcl and Awk scripts are used to do the analysis. Following 7 basic traffics are identified in the network as shown in the simulation snapshot for IEEE 14 bus system in Figure 15:

1. All the Substation (S/S) to Control Center (CC)
2. Control Center to Control Substation (Generating stations and substation having control units like transformers and reactors)
3. Special Protection Scheme (SPS) substation to SPS
4. SPS to SPS substation
5. Generating substation to Generating substation
6. SPSs to Control Center
7. Control Center to Control Center

Here, SPS is used generically to represent any wide-area closed-loop control and/or protection. An SPS may not be located at the control center or at any substation and it needs data only from a few locations and issues commands back to few substations only. SPS can be especially useful for transient stability applications where latency is of significant importance.

The key assumptions that have to be made in the simulation are discussed in Section 6.3.2 and Section 6.3.3. Similar network simulations [41] have been carried out before and some of the assumptions in this work are similar to [42], [41]- [43]. The main difference in this work is that the assumptions are developed by starting from the power network,

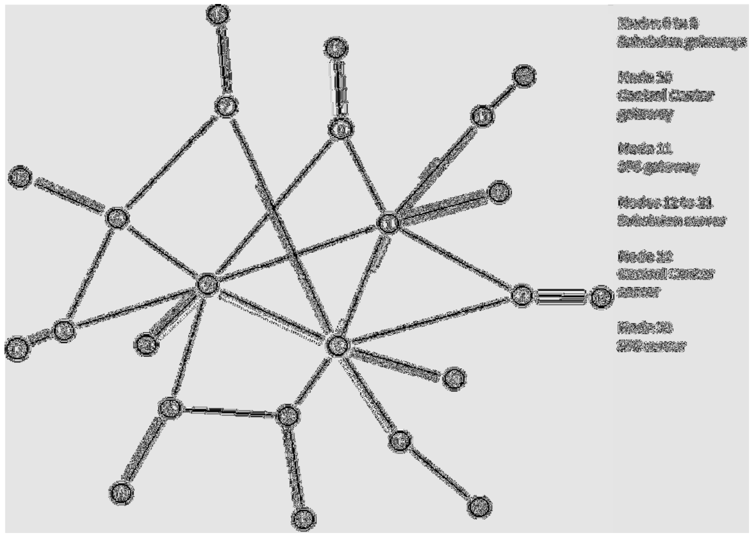


Figure 15 Snapshot of 14 bus NS2 simulations with 6 traffic types

substation configurations and anticipated on-line applications to determine the data transfer needs. Different scenarios can be studied using different protocols, routing algorithms, data formats, sampling rates, and communication infrastructure. Also, accuracy of the results would depend on the modeling details and some of it may require changing the NS2 source code. This work focuses on presenting a methodology to simulate a possible communication scenario using power system topology information with design parameters based on smart grid application requirements.

6.3.2 Assumptions for Power Systems Data

The information that is required to calculate the amount of data for an actual power system is substation configuration and connected equipment (generators, reactors, and transformers). Location of the application servers (control center and SPS) and location of controls along with their individual data needs then define the amount of data that need to be communicated. For a real power system this information is easily available.

The connection between substations is from the given power system network data and the communication network overlays that. In case of multiple transmission lines between two substations, only one communication link is considered to connect them. Control center (CC) node is connected to the substation node having maximum number of communication links. This will allow distribution of traffic to the CC node through multiple paths. Similarly SPSs are connected to the available substation nodes having maximum connectivity. This completes a communication network graph of network gateways for a given power system. Each gateway is connected to a server. Power system applications and PDCs are running in these servers. As an integrity check and to run communication simulation, a computer program is developed to verify the connectivity of the network graph obtained after this step.

The second step is to estimate packet sizes in each of these substations, control centers and SPSs. Packet size is calculated for data traffic between substation and control center (type-1 traffic) as follows:

1. The configuration for each substation is usually known (for the examples in Sections 6.3.4 and 6.3.5. a breaker and half scheme is assumed for all substations). The 3 phase quantities for each section and CB status are measured and communicated.
2. Channels for each PMU are known (assumed to have 9 analog channels and 9 digital channels in examples below).
3. Given the number of PMUs and number of phasors in a substation, the size of C37.118 data frame is calculated.

Type-2 to type-6 traffic have packet sizes smaller than the type-1 traffic because only selected data for control purposes constitute these types.

For the two example power networks used in Sections 6.3.4 and 6.3.5, the power network data is available but not the substation details. The identification of substation configurations, control substations, control centers and SPSs is first step to determine the data traffic for our simulation studies. A computer program is developed to do this step. Buses that are connected through transformers are combined into one communication node per substation. Then the number of feeders in each of these substations is calculated. On top of the substation, one control center per zone is added where each zone is treated as one control area. SPSs are added assuming that a group of approximately 10 substations will be connected to one SPS.

6.3.3 Assumptions for Communication Simulation

After obtaining the network graph and data requirements based on the Section 6.3.1, the following assumptions are made for communications:

1. As discussed in Section 6.2.2, CBR over UDP is used to simulate the traffic with MTU size as 1500 bytes.
2. As a base case, duplex links of sufficiently high bandwidth are assumed between substations as OC-3 i.e. 155 Mbps and the receiving link for the CC/SPS as OC-12 i.e. 622 Mbps.
3. To observe larger queuing delays and to avoid packet drops, based on few simulation runs, the queue size is assumed as 5000 packets.
4. To simulate large network such that every packet reaches its destination node without being dropped, based on few simulations run, the Time-To-Live (TTL) value is set to 64 hops.
5. Number of CC and SPSs are chosen based on the size of the network.
6. Data set out from the substation/SPS/Control center server is in C37.118 format (fixed 16-bit).

7. The routing used by NS2 is the shortest route (number of hops) and is kept default as static.
8. It is assumed that the system is under normal operation and only Data frames are being communicated.
9. The sampling rate is assumed to be 60 samples/second for all the traffic sources
10. The processing delays in gateways (10-100 microseconds [44]) are assumed to be zero. Here gateways are considered as forwarding nodes only to simulate communications. Data aggregation/ processing occur at end nodes/PDC only and this delay is considered as computation delay and not communication delay. The computation delays can be added at each end node for specific application without making it a part of the communication simulation.
11. The communication is assumed uniform i.e. no spikes in data.
12. To calculate propagation delay, the network reactance is converted into miles [45].
13. Propagation delay between server and gateway is assumed to be 1 microsecond.

NS2 simulation is run after following the steps/assumptions discussed above. NS2 generates a trace file with all the events (packet drop, packet receive, etc.) for each packet generated in the system. These files are analyzed using various computer programs [46] for results on latency and bandwidth presented in Section 6.3.4 and Section 6.3.5.

6.3.4 WECC Results

6.3.4.1 WECC 225 Bus Power System

The WECC 225 bus is a reduced model of the WECC transmission network though representing almost same geographical area. Power system statistics after following the

Table 6.3 WECC statistics after node reduction

S.No.	Parameter	Value
1	*Buses*	225
2	*Substations*	161
3	*Control Center*	1
4	*SPS*	16
5	*Generating S/S*	31
6	*Control S/S*	58
7	*SPS S/S*	160

Table 6.4 Packet size of traffic type-1

Maximum (Bytes)	Minimum (Bytes)	Average (Bytes)	Median (Bytes)
1540	148	401	280

Table 6.5 Link bandwidth usage

Topology	Max. of used links (Mbps)	Min. of used links (Mbps)	Average of used links (Mbps)	Median of used links (Mbps)	% of unused Gw2Gw links
Min S.T.	58.75	0.10	5.46	0.39	28.6%
1CC links	45.60	0.08	3.34	0.62	11.4%
3CC links	46.80	0.10	2.97	0.51	11.7%
5CC links	44.09	0.08	2.03	0.38	10.8%

methodology discussed above are presented in Table 6.3. Note that only one control center is assumed and hence six traffic types for WECC.

6.3.4.2 Packet Size

As shown in Table 6.4 the maximum packet size for type-1 traffic in a substation can be as much as 1540 bytes. Also, packet sizes for a given power system would be same for all communication topologies. Type-1 to type-6 traffic packet sizes are assumed to be 250 bytes for the simulation purposes which is lower than the median of type-1 packet size.

6.3.4.3 Average Link Usage for Different Communication Topologies

Table 6.5 shows simulation for four different cases. In the first simulation Kruskal's algorithm [47] is used to get minimum spanning tree (S.T.) for the communication network. This gives the minimum number of links required for networked communication of a given power system. In next three simulations the complete graph is used as obtained after node reduction program with variation in number of control center links, for example, 3 CC link means connecting CC gateway to the three substation gateways (with maximum connectivity) in the network. Clearly, connecting control center with some substations geographically distant is really important as it makes the routing really efficient by avoiding bottlenecks and providing alternate shortest path to the traffic. Also, spanning tree configuration should not be used from reliability perspective. For full topology case, by adding just 4 more CC links 40% on link usage can be saved and delays reduces to ¼ for 5CC link configuration compared to 1CC link configuration. Hence, this helps in decreasing delays by adding just few links. Also, notice that average bandwidth usage decreases because now packet takes shorter route and traverses lesser link to reach its destination.

Table 6.6 Maximum delays for different traffic types

Network Topology	Type 1 (ms)	Type2 (ms)	Type3 (ms)	Type4 (ms)	Type5 (ms)	Type6 (ms)
Min S.T.	49.9	40.3	45.1	46.3	44.0	40.3
1CC links	26.2	27.6	26.6	27.1	29.4	23.9
3CC links	19.2	19.1	25.2	25.5	29.3	16.4
5CC links	11.7	5.2	13.8	12.9	15.6	4.5

Table 6.7 Queuing delays

Topology	Maximum (μs)	Minimum (μs)	Average (μs)	Links with queue delay as zero (%)
Min S.T.	586	0	17.7	53.1%
1CC links	441	0	13.7	60.1%
3CC links	259	0	12.0	60.2%
5CC links	354	0	12.6	60.8%

Table 6.8 Number of hops

Topology	Max	Min	Average	Median
Min S.T.	43	2	19	18
1CC links	28	2	12.2	12
3CC links	26	2	10.6	10
5CC links	15	2	7.0	7

6.3.4.4 Maximum Delays in Traffic for Different Communication Topologies

Table 6.6 shows the maximum delays for the six identified traffic types. With the large bandwidth of fiber optics and meshed communication, it can be noted that maximum delays for all the traffic types are well within the latency requirements for most applications.

6.3.4.5 Queuing Delays

Table 6.7 shows the calculated queuing delays for each system. Notice that with the huge bandwidth available queuing delays are almost negligible. Queuing delay can increase really fast if the network get congested or if the bandwidths on incoming link and outgoing link are disproportionate.

6.3.4.6 Number of Hops

Table 6.8 shows the number of hops that a packet has to traverse assuming shortest hop routing algorithm. This data will help understand how much an issue can processing delays at gateways can be if they happen to increase due to more intense routing mechanisms or other reasons like security.

6.3.4.7 Simulations with Varying Bandwidth

Previously, various network parameters are calculated using the base bandwidth mentioned in assumptions. In this section 3CC link configuration is assumed and used estimated bandwidth of Section 6.3.4.3 as the actual required bandwidth. Table 6.10 shows the result on delays when the bandwidth is varied on the gateway (Gw) to gateway links (G2G) as the multiple of actual bandwidth. Further for the first three cases of results in Table 6.10, same bandwidth on gateway to server (G2S) links is assumed as pointed in Table 6.9 Notice that when the bandwidth is scaled, it should be scaled on the complete network i.e. both on G2G and G2S links or else queuing delay increases. Also as shown in Table 6.10 by using twice the actual bandwidth one can get delays similar to base case. Recalculated bandwidth consumption for each case is shown in Table 6.11.

Table 6.9 Assumed bandwidth for simulations

Bandwidth	Base Case (D3-D6) (Mbps)	Actual Usage (Mbps)
Btw CC server and CC Gw	Duplex 622	50Mbps (Gw to Server) / 10Mbps(Server to Gw)
Btw Sps server and Sps Gw	Duplex 622	Simplex 2Mbps
Btw S/S server and S/S Gw	Duplex 155	Simplex 5Mbps
Btw CC Gw and S/S Gw	Duplex 622	Simplex Integer(actual)+1
Btw Sps Gw and S/S Gw	Duplex 622	Simplex Integer(actual)+1
Btw S/S Gw and S/S Gw	Duplex 155	Simplex Integer(actual)+1

Table 6.10 Delays in WECC system with varying bandwidth

Bandwidth of G2G links	Max. Delay (ms)	Avg. of Max Delay of each traffic type (ms)	Max. Queuing Delay(µs)	Avg. Queuing Delay(µs)
Actual BW/2	167.0	91.2	43736	3413
Actual BW	55.3	39.3	8018	694
Actual BW*2	40.8	31.3	8018	595
Actual BW*2	38.1	28.3	4009	342
Actual BW*5	32.1	24.0	1603	131
622Mbps and 155Mbps	29.3	22.4	259	12

Table 6.11 Actual link bandwidth requirement for WECC

Communication infrastructure	Max. G2G Bandwidth (Mbps)	Average G2G Bandwidth (Mbps)	Median G2G Bandwidth (Mbps)
Actual BW/2	24	2.59	1
Actual BW	47	4.48	2
Actual BW*2	94	8.28	3
Actual BW*2	94	8.28	3
Actual BW*5	235	19.88	6
622Mbps and 155Mbps	622	194.56	155

6.3.5 Poland 2383 Bus System Results

6.3.5.1 Polish Power System

Polish power system discussed here is a high voltage power system of Poland above 110kV which is divided into 6 zones. Zone 1-5 is shown in Figure 16 [48]. Zone-6 represents all the tie lines connected to the neighboring countries. For simulation purposes each of the Zone-6 is included bus into the respective Zone 1-5 to which it is actually connected. Each zone will have its own control center and the only interaction between zones is between their respective Control centers. The inter control center communication would have separate direct connection using optical fibers over transmission line. The number of substations being more than 225 in each zone, 5CC and 7CC link communication infrastructure is used to simulate traffic in each zone. Network statistics are presented in Table 6.12 and
Table 6.13.

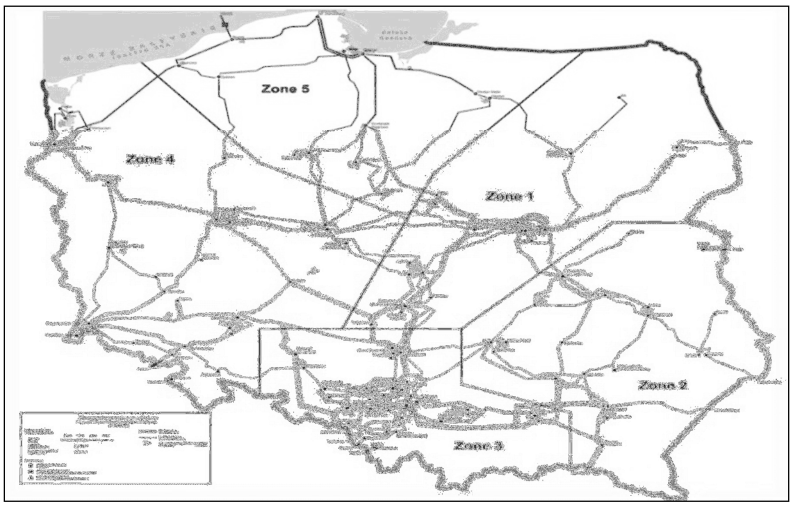


Figure 16 Polish power system zones

Table 6.12 Overall statistics of the polish system

S.No.	Parameter	Value
1	*Buses*	2383
2	*Substations*	2216
3	*Control Center*	6
4	*SPS*	219
5	*Generating S/S*	305
6	*Control S/S*	386
7	*SPS SS*	2190

Table 6.13 Zonal statistics of the polish system

Parameter	Zone1	Zone2	Zone3	Zone4	Zone5
Substations	343	259	831	515	268
Control Center	1	1	1	1	1
SPS	34	25	83	51	26
Generating S/S	42	36	88	92	47
Control S/S	56	51	104	112	63
SPS SS	340	250	830	510	260
CC links	5	5	7	7	5

6.3.5.2 Packet Size for Different Zones

After node reduction, packet size is calculated for data traffic for each zone as shown in Table 6.14.

6.3.5.3 Average Link Usage for Different Zones Using 5CC/7CC Link Communication Topologies

The bandwidth usage is estimated only on the G2G links and is shown in Table 6.15.

Table 6.14 Packet size of traffic type-1

Zone	Maximum (Bytes)	Minimum (Bytes)	Average (Bytes)	Median (Bytes)
1	1438	148	290.7	262
2	1204	160	303.1	262
3	1540	148	265.6	262
4	1426	148	281.2	262
5	1078	148	293.8	262

Table 6.15 Average G2G link bandwidth usage in Mbps

Max. of used links (Mbps)	Min. of used links (Mbps)	Average of used links (Mbps)	Median of used links (Mbps)	% of unused Gw2Gw links
126.77	0.09	4.68	0.94	2.96

Table 6.16 Maximum delays in traffic for each zone

Zone	Type-1 (ms)	Type-2 (ms)	Type-3 (ms)	Type-4 (ms)	Type-5 (ms)	Type-6 (ms)
1	12.4	11.5	22.2	28.7	23.6	11.9
2	12.7	10.8	19.7	24.6	25.3	10.2
3	14.2	13.6	25.4	27.9	25.9	11.2
4	12.5	11.6	18.0	22.9	25.8	10.2
5	15.4	11.1	26.3	26.6	21.0	10.0

Table 6.17 Number of hops

Zone	Max	Min	Average	Median
1	18	2	7.23	7
2	15	2	7.23	7
3	20	2	8.12	8
4	20	2	7.71	8
5	15	2	6.85	7

6.3.5.4 Maximum Delays in Traffic for Different Zones

From experience of the WECC system twice the actual bandwidth usage is taken as new bandwidth and estimated the delays for the Polish system as shown in
Table 6.16. This is well within the latency requirements for most applications.

6.3.5.5 Number of Hops

Table 6.17 shows the number of hops that a packet has to pass during the simulation assuming shortest path routing algorithm.

6.3.5.6 Control Center to Control Center Simulation

Once the data reaches its zonal control center, state estimation is performed for that particular zone. Each zonal control center then sends its information to all the neighboring control centers. Each control center has the static data of system topology for the complete national grid. Control center sometime performs the state estimation using full system topology, local measurements and usually state estimated data from neighboring grid. The problem in just sending the estimated states to the neighboring control center is that the changes in the substation configurations are not reflected in the state estimated data. To take this into account it is assumed that all the measurements from one system to another along with any changes in substation configurations are sent. Hence state estimation at control center can then be performed using local measurements and corrected using system wide measurements. The computation delays in the control center can be of significant importance here.

Currently, the data sharing between control centers is done using Inter Control Center Protocol (ICCP) which is a relatively slow protocol. The data shared between control centers being huge and latency being not the prime concern for EMS application FTP/TCP kind of traffic is assumed. Also it is not suggested to use TCP with UDP as TCP needs to allocate resources on the network before transmission and does get kicked out by UDP. Using TCP helps us in taking care of packet drops, as dropping packets is a concern for data which is collected approximately in a second. In communication infrastructure shown in Figure 17, control center shares its information with the all control centers using point to point links. This network is obtained from the location of the zones and by finding shortest path to connect these zonal control centers assuming the optical fiber would run over transmission line. Because there would be only few changes in the system topology over time, mainly raw measurements results would constitute to the size of the file. The estimated size of the data file time tagged at one particular time is shown in Table 6.18.

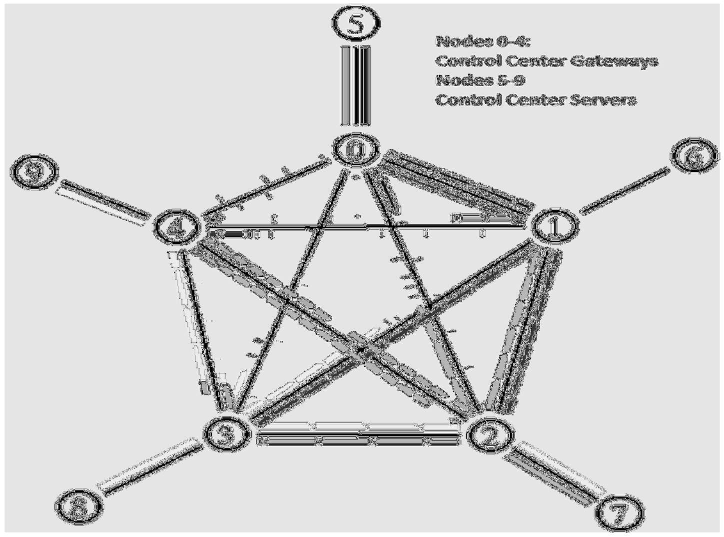


Figure 17 Communication topology to connect control centers for Polish system

Table 6.18 File size of raw measurements and breaker status

Zone	File size (bytes)
1	99712
2	78514
3	220758
4	144842
5	78748

Table 6.19 Delay for inter control center communications

Bandwidth for CC to CC links (Mbps)	Delay in CC to CC communication	
	Maximum (ms)	Average (ms)
25	118.4	69.1
50	84.3	46.3
75	71.1	39.2
100	65.5	35.5

Table 6.20 Delay in exchanging complete information across polish system

Zone	Max delay for type-1 traffic (ms)	Max CC to CC delay (ms)	Total delay (ms)
1	12.4	66.5	78.9
2	12.7	65.0	77.7
3	14.2	50.8	65.0
4	12.5	61.3	73.8
5	15.4	84.3	99.7

Table 6.19 shows that delays to send a complete chunk of file from one control center to another varies as the link bandwidth is varied. Based on the understanding for delays in inter control center communication 50Mbps bandwidth is assumed and then calculated total delays shown in Table 6.20. These delays represent maximum total delay for packets tagged at time t=0 to get distributed to all the control centers. Notice that at the control center separate files of raw measurements with different time tags are created. For state estimation purpose one file can be picked up and transmitted every one second.

In this section the method for simulation of communication network using two case studies is presented. The results obtained include the expected communication latencies for various values of bandwidths. The next step is to examine the effects of these latencies on performance of the controllers. This is taken up in section 6.4, with an example of wide-area damping controller for a two area system.

6.4 Effects of Communication Delay on Controller Performance

6.4.1 Study on 4 Machine 2 Area System

In this section, how the communication delays affect the dynamic stability of a system via the design of wide area damping controller (WADC) is studied for a 4 machine 11 bus system [49]. Communication links can also be used to transport data over long distance to support close-loop control applications such as WADC. The controllers using remote signals have certain constraints on latency. The goal of this study is to test if existing network parameters can satisfy such constraints.

6.4.2 Communication Network Scenario

First, a communication scenario is generated based on topology information of a power system. Several assumptions are made about the long-distance model of fiber optic fibers, package size and protocol used on each layer. This scenario is then simulated in NS-3 under different values of bandwidth. 60 data package per second are sent from nodes that represent a substation with PMU installed to the communication node at the control center. Information like data size, package ID, related time stamp for each package is recorded. The sending and receiving time is sorted by the IP of its sending node and calculates the average time delay on certain communication links carrying the input data for the controller. In order to determine the stability of a power system after disturbance, the time delay calculated above is then applied to a Simulink model for the two-area four-machine system. The stability is determined by observing parameters such as rotor angles of generators. The single line diagram of the test system is shown in Figure 18. And Figure 19 illustrates the topology of the communication network which consists of 8 nodes. The substations having multiple voltage levels are grouped under one single communication node and the node no. 8 represents the control center. The WADC is installed on generator at node 1. The controller at node 1 receives the remote signal from node 3 via the control center at node 8. However it should be noted that a major part of the time delay in data flow occurs during the communication between nodes 3 to 8, hence this is taken as the time delay for the controller. Considering that fiber-optic cables are used, a repeater is added every 10km in the network links to keep the strength of optical

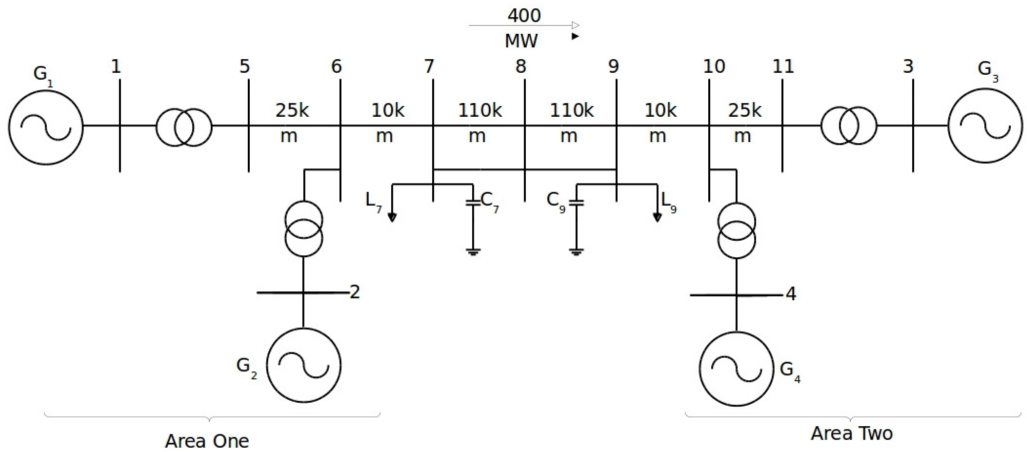


Figure 18 Two-area four-machine power system

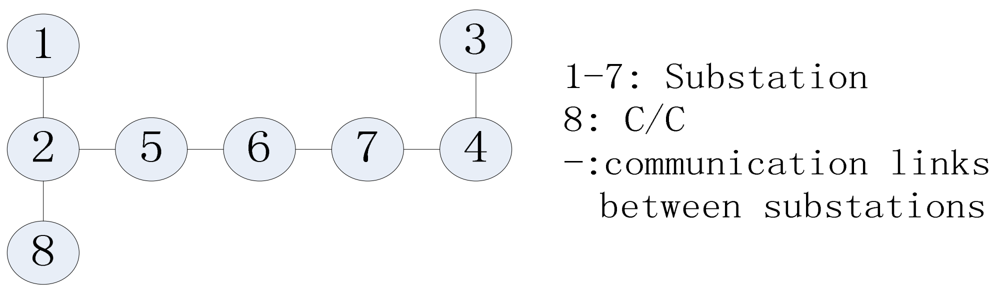


Figure 19 Substation connection diagram

signal. Coordinates of all communication nodes including substations and repeaters are generated so that this scenario can be visualized in the animation tool provided by NS-3.

The last part of the scenario stores system settings like the bandwidth and the number of CBR connections. It is assumed that all data measured by different PMUs in the same substation will be sent through only one data package. Therefore, all PMUs in this substation are represented by a single communication node during simulation. The data flow between substations and the control center is much larger than the data flow of other types of communication. So only this kind of connection is simulated to calculate the time delay. Each PMU has 9 analog channels and 9 digital channels, and measures 6 phasors. The number of PMUs is calculated from the number of feeders attached to that substation. Based on header information from the C37.118 standard, the smallest size is about 440 bytes and the largest is about 544 bytes. The number of packets is assumed to be 60 per second.

6.4.3 Communication Network Simulation Results

Simulations are carried out with two different bandwidths, namely 10 Mbps and 3 Mbps. The average time delays are listed in Table 6.21. It is observed that time delay from node

3 to node 8 is 79 milliseconds with 10 Mbps link as opposed to 210 milliseconds with 3 Mbps link.

6.4.4 Modeling of WADC with Delay Using MATLAB SIMULINK

Having determined the communication delays, the next step is to design a WADC for the above 4 machine system. The system shown in Figure 18 consists of two fully symmetrical areas connected together by two 230 kV lines of 220 km length. Identical speed regulators are further assumed to be installed at all locations, in addition to fast static exciters with a 200 gain. The load is represented as constant impedances and split between the areas in such a way that area 1 is exporting 400MW to area 2. To damp the local mode, conventional PSS using Δω as an input (ω is the local generator speed) is installed on all plants, which structure is shown in Figure 20.

WADC is added to the exciter at G1 as in Figure 21. The input signal is the changing part of differential speed signal between the remote generator and the local generator (

Table 6.21 NS-3 simulation results

Bandwidth (Mbps)	**Average Time delay (ms)**	**Time delay between nodes 3- 8 (ms)**	**Variance (s^2)**
10	39	79	3.3E-32
3	132	210	1.36E-03

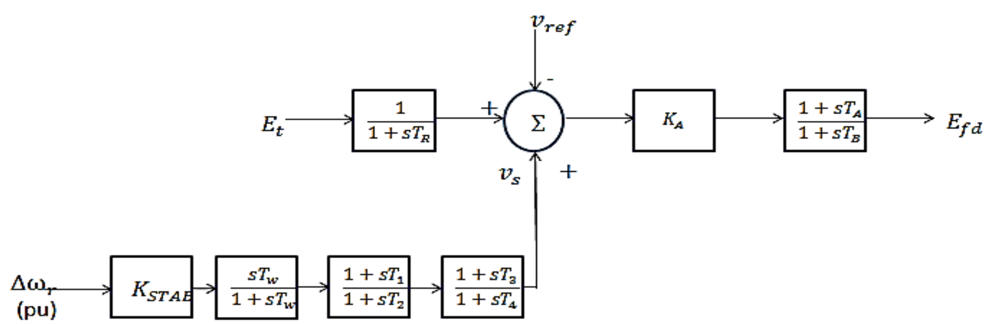


Figure 20 Excitation system with PSS

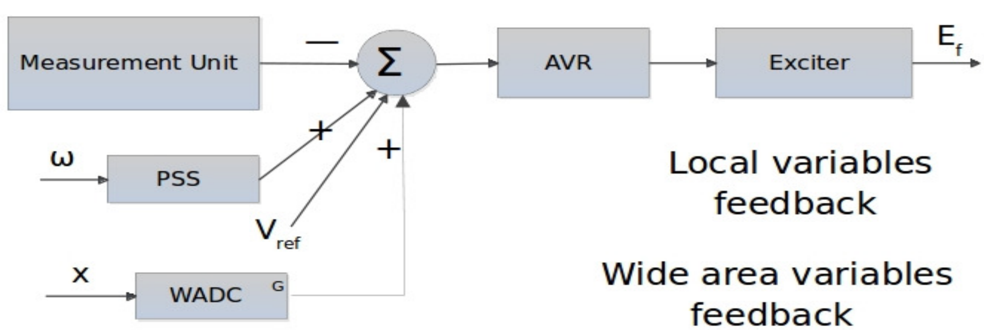


Figure 21 Excitation system with WADC with remote signal

$\Delta(\omega_3 - \omega_1)$). The transfer function of the controller is calculated based on residues compensation [50]. The parameters are as follows:

$$H_{PSS}(s) = 30 \frac{10s}{1+10s} \left(\frac{1+0.05s}{1+0.03S}\right)\left(\frac{1+3.0s}{1+5.4s}\right)$$

In the above figure a time delay as per the assumed bandwidth is introduced in the WADC input signal. To test the dynamic stability in this system, a 5%-magnitude pulse is used, applied at the voltage reference of the exciter at G1 for 12 cycles.

6.4.5 WADC Simulation Results

During the simulation, the input of the damping controller is delayed by a certain time, calculated by the NS-3 results shown above. Relative rotor angles are plotted to determine the stability. The rotor angle of generator 4 (M4) is used as reference value. Figure 22 shows the results with 10 Mbps bandwidth (a time delay of 79 milliseconds), whereas Figure 23 shows the results with 3 Mbps (a time delay of 210 milliseconds).

From the results the oscillation of rotor angles after the disturbance can be observed. With a bandwidth of 10 Mbps, this oscillation is damped out by WADC at the end of simulation. However in the 3Mbps case, that oscillation makes the whole system unstable. The amplitude of oscillation keeps growing with time. So one can say that if the network condition is not good enough, the time delay introduced by remote-data transport can completely change the stability of a power system.

So far only centralized communication architecture is studied. It is observed that, when the system size becomes larger, the data from far away substations have to take many hops before reaching the central control center. This results in latencies well beyond our target of keeping latencies below 100 msec.

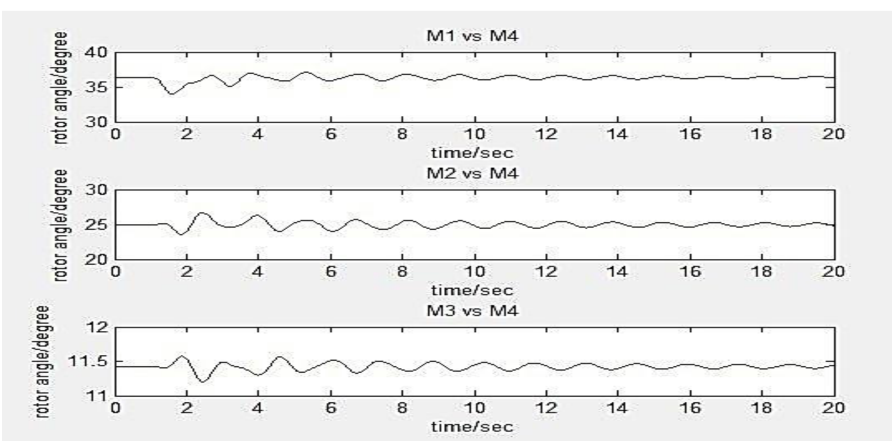


Figure 22 System performance with 10 Mbps. The system is stable.

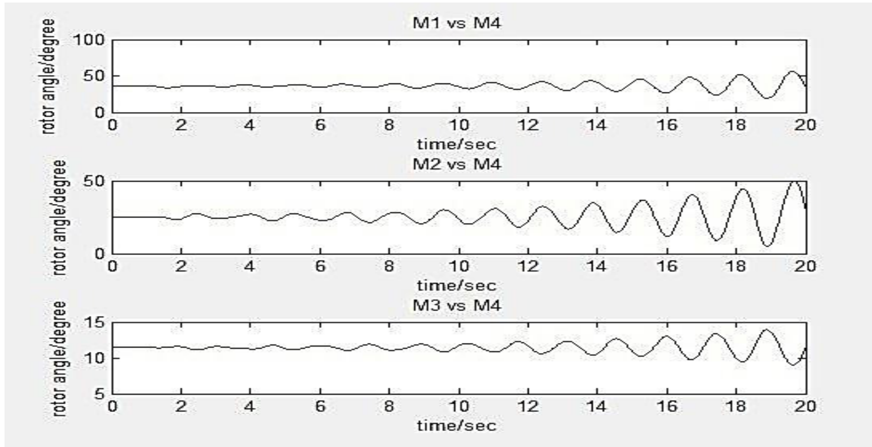


Figure 23 System performance with 3 Mbps. The system is unstable.

To address this problem, design of distributed architecture is presented in the section 6.5, using the concept of mutually interconnected local control centers. The overall latencies are shown to be lesser even when using lower bandwidth links.

6.5 Comparison of Centralized and Distributed Architectures

NS-3 Simulations are carried out on IEEE 118-buses system to determine the influence of distributed communication architecture on bandwidth requirement. As a contrast, results of traditional centralized communication network are also included in this section.

6.5.1 System Information

IEEE 118-buses test system [51], as shown both in Figure 24 and Figure 25 has 109 substations which are divided into 3 areas after the node reduction. All these substations send out their own measurement data to control center (Topology 1) or local center (Topology 2). It is assumed that all communication links are built along the same path as transmission lines. Packet sizes are calculated based on the number of feeders and data frame format defined by IEEE C37.118 standard. The amount of data carried by such packets varies from 234 bytes to 1440 Bytes. Detailed information about the topologies and packet sizes are listed in Table 6.22 and Table 6.23.

In the test system, 52 substations which have generators are classified as control substations. It means that they will not only dispatch PMU data, but also receive control data from control center or local center. The size of control data is assumed to be 200 bytes, less the minimum packet size of measurement data. The reason for this is that in case of wide-area control signal, usually a few parameters are needed from remote control substation, which imply that the packet size of control data should be smaller than that of measurement data.

The second communication type is not included in our previous simulation applied on two-area system. It is configured here to illustrate more detail about the time delay introduced by communication network. And some following results of this full version of communication architecture do confirm that adding this kind of data will not change our bandwidth requirement to avoid intolerable time delay.

Table 6.22 Statistics of IEEE 118 bus system

Parameters	Topology 1 (Centralized)	Topology 2 (Distributed)		
		Area 1	**Area 2**	**Area 3**
Buses	118	37	45	36
Substations (SS)	109	34	40	35
Control Centers (CC)	1	1	1	1
Generation Substations (GSS)	52	16	19	17
Communication Links	161	50	59	52

Table 6.23 Statistics of packet sizes

Maximum (bytes)	Minimum (bytes)	Average (bytes)	Median (bytes)
1440	234	409	336

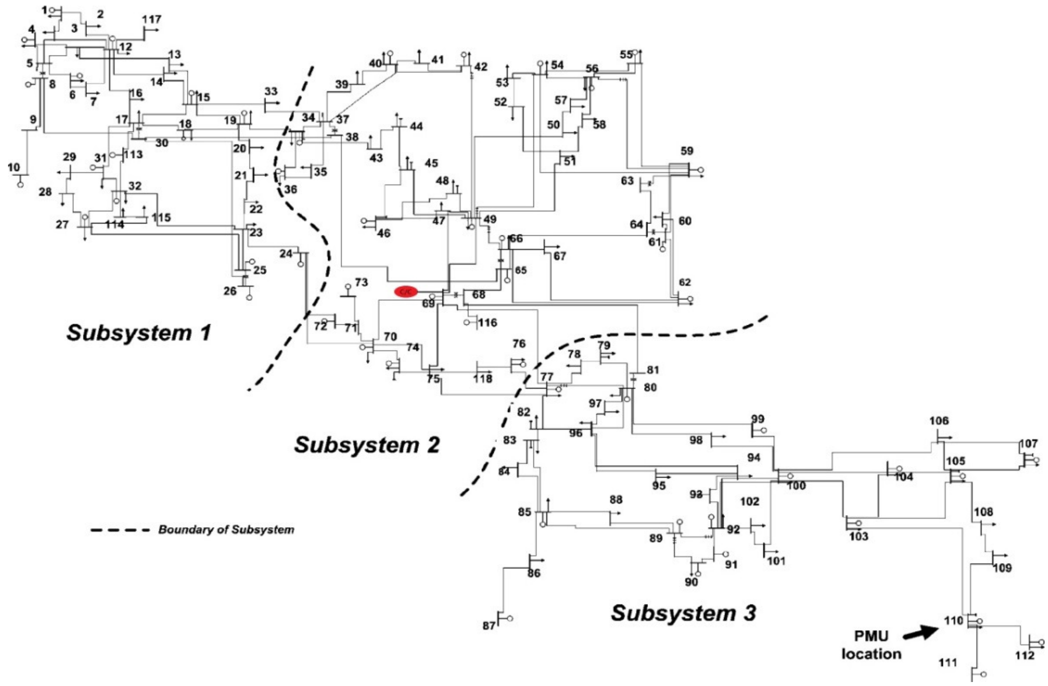


Figure 24 Topology 1: Centralized architecture

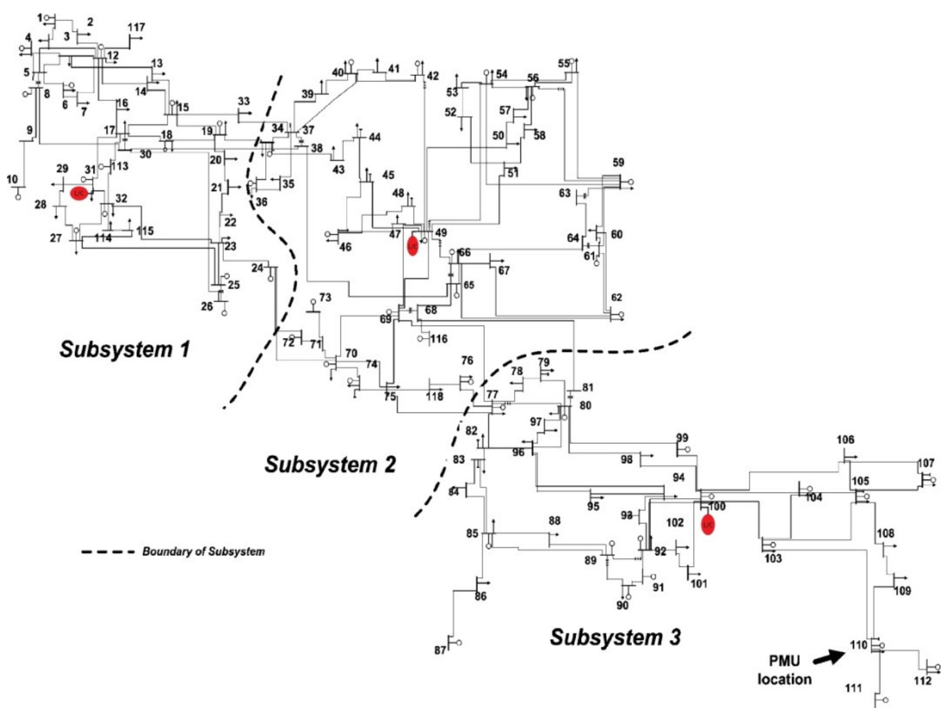


Figure 25 Topology 2: Distributed architecture

6.5.2 Topology 1: Centralized Communication Architecture

As shown in Figure 24, there is only one control center in the grid which is attached to bus 69. All communications are built between substations and control center. PMU measurements from different areas are transported to, stored and processed in the same place. Control center also send out data packets with control signal to all control substations at a rate of 60 packets per second to meet high-data-rate requirement of wide-area controller.

6.5.3 Topology 2: Distributed Communication Architecture

To reduce demanded bandwidth and to improve performance of communication network, a distributed topology is designed for IEEE 118-buses system. Instead of just 1 control center, 3 local centers are set up at bus 31 (local center 1), bus 49 (local center 2) and bus 100 (local center 3) as shown in Figure 25 to handle the data which is measured in local area. This means that in this topology substation only send PMU data to and receive control data from its local center, which will reduce the stress of transporting large amount of data and is supposed to reduce the average delay in the network.

Other than communication links between substations and local center, data transmission among local centers are also simulated in Topology 2. It is assumed that local centers only share indispensable information with each other with same sending rate (60 packets/s) and packet size (200 bytes) as the parameters of control data. Considering that communication between local centers should not share the same physical middleware with links between substations and local center. A communication wire is built between local center 1 and local center 3.

6.5.4 Simulation Results

6.5.4.1 Results for Topology 1: Centralized Architecture

The same method of calculating time delay as in the two-area case is followed. It is assumed that WADC is installed on bus 112 (Substation 103) and the wide-are signal is measured at bus 1 (Substation 1). The time delay from substation 1 to control center and the delay from the control center to substation 103 is summed up to calculate the total delay value seen by the controller. If this delay is less than 100ms, the latency requirement of different kinds of controllers is well met since from the grid topology one can tell that the considered case is one of the worst cases.

The results for Topology 1 are listed in Table 6.24. NS-3 is used to simulate this topology with bandwidth from 100 Mbps to 20 Mbps. From the results one can see that in the 100 Mbps scenario, the total time delay is only 29.3ms, which is far more less than the limit of 100ms. And for a value larger than 20 Mbps, time delay over wide-are signal transportation increase slowly as the bandwidth is cut down as shown in Figure 26. When 25 Mbps is used in the simulation, time delay value goes up to 70.6ms, increasing by 140.8%. Clearly this result is still within latency requirement.

However, when the bandwidth reaches 20 Mbps, one can observe a huge step up as the time delay is 154.7ms. According to the demand of time delay for transient stability application, this network can no longer support the damping controller.

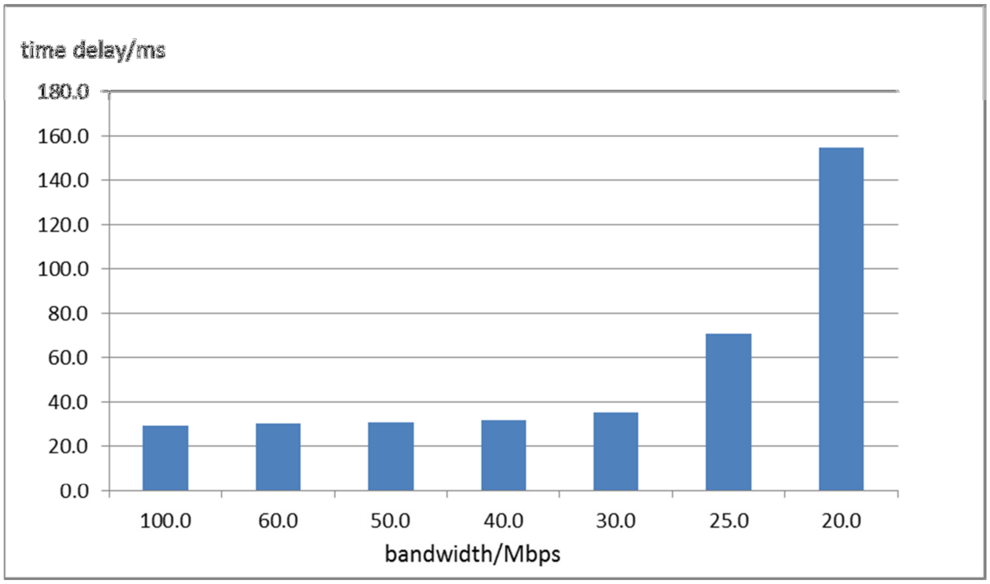


Figure 26 Total time delay vs. bandwidth for Topology 1

Table 6.24 Time-delay results for Topology 1

Bandwidth (Mbps)	Time delay from SS1 to CC in (msec)	Time delay from CC to SS103 in (msec)	Total time delay (msec)	Increased percentage compared to 100Mbps case (%)
100	14.3	15.0	29.3	0.0
60	14.5	15.7	30.2	3.0
50	14.6	16.1	30.6	4.5
40	15.0	16.6	31.6	7.7
30	18.0	17.4	35.4	20.9
25	52.5	18.1	70.6	140.8
20	135.6	19.2	154.7	427.6

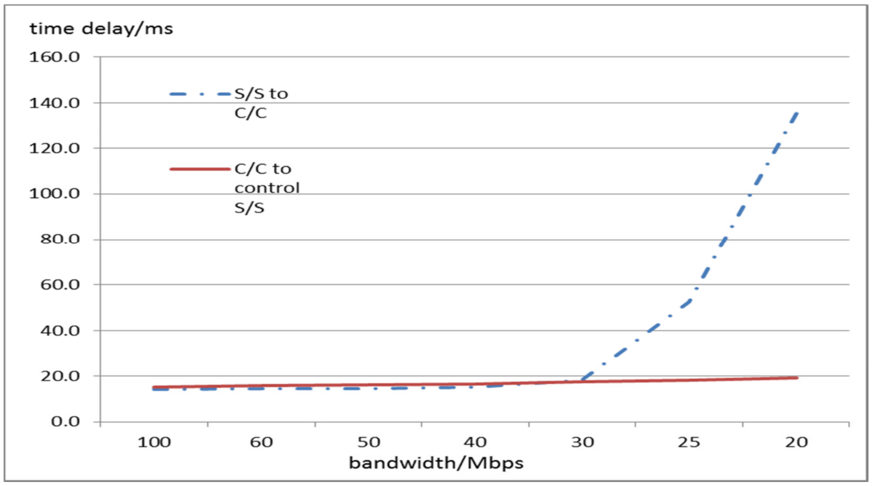


Figure 27 Measurement data delay and control data delay

If the data in column 2 and column 3 observed separately as shown in Figure 27, it shows different increasing rates as the bandwidth is reduced. The delay for measurement data, listed in column 2 is initially less than the delay for control data, listed in column 3 in the 100Mbps scenario. However in 20Mbps scenario, measurement data delay is almost 7 times as the control data delay. This illustrates the conclusion that when the network is about to have a congestion, the time delay between substation and control center account for the major part of total delay. It also validates our previous assumption that the control data packets can be neglected in the simulation.

6.5.4.2 Results for Topology 2

The location of WADC and remote control signal used are same as in Topology 1. But since controller and its control signal belong to different areas, the communication link is more complex in Topology 2. In order to transport a wide-area measurement, a communication link is built from local center 1 to local center 3. The simulation results are listed in Table 6.25.

From the results of time delay between substation and its local center, one can tell that new topology helps lower our bandwidth requirement. In Topology 2, one can meet the time delay limit with a bandwidth as low as 10Mbps, which is a great progress compared to results in Topology 1.

It also shows that the distributed network introduce shorter delay with the same network environment. For example, in 50Mbps scenario Topology 1 introduce a delay of 30.6ms into the system while Topology2 introduce a delay of 21.2ms. The delay on measurement data and control data decrease due to the design of local control center, and the delay caused by data exchange between local centers is even smaller because of the link added

Table 6.25 Time-delay results for Topology 2

Bandwidth (Mbps)	Time delay between S/S 1 and L/C 1(msec)	Time delay between L/C 1 and L/C 3 (msec)	Time delay between L/C 3 and S/S 102(msec)	Total time delay (msec)	Increased % compared to 100Mbps case (%)
100	10.2	2.0	8.4	20.6	0.0
60	10.3	2.0	8.6	21.0	1.9
50	10.4	2.0	8.7	21.2	2.8
40	10.5	2.0	8.9	21.4	4.2
30	10.6	2.1	9.2	21.9	6.5
25	10.8	2.1	9.5	22.3	8.4
20	11.1	2.1	9.8	23.1	12.0
10	16.2	2.2	11.7	30.1	46.3
5	200.8	2.4	15.4	218.5	961.9

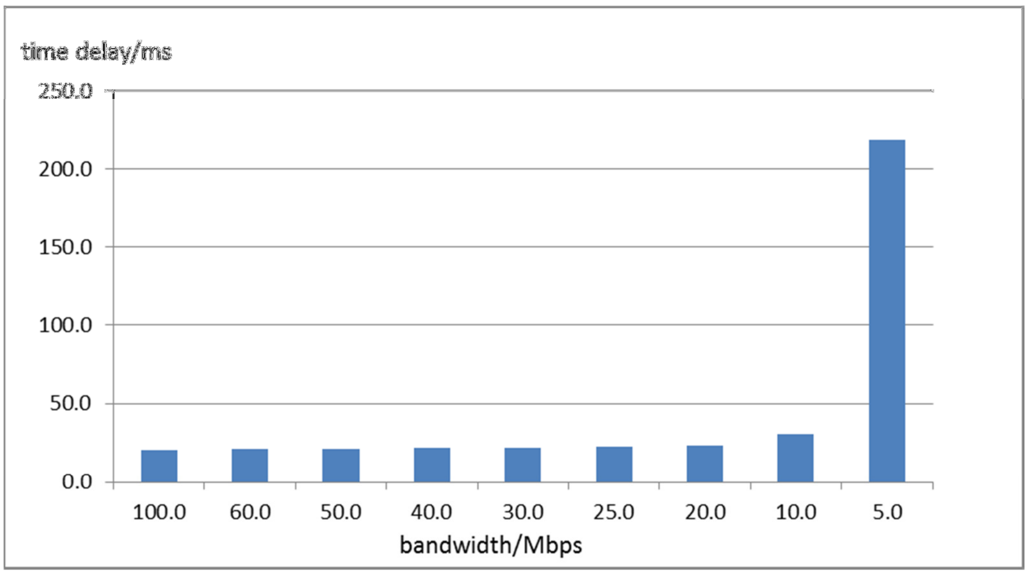


Figure 28 Total time delay vs. bandwidth for Topology 2

between local center 1 and local center 3. Figure 28 also illustrates that with different delay values, the curves between time delay and bandwidth share the same trend in both topologies.

6.5.4.3 Conclusion on Centralized and Distributed Topologies

Based on simulation results of two communication topologies, it is clear that the distributed architecture has more advantages than the centralized one. Topology 2 can lower the minimum network bandwidth and provide shorter time delay, which means that it is more reliable and a more appropriate choice for a power system with wide-area damping controller.

By comparing the delay over measurement data and control data, the assumption that measurement data is the main cause of congestion in low bandwidth scenario is also confirmed. Thus, one can overlook the control packets in process of determining minimum bandwidth.

In this section, only the time delay is simulated and the results are not applied on damping controller. How this delay changes the transient stability in IEEE 118-buses system needs to be explored.

6.6 Conclusions

In this section the evolving trend of wide area power system control towards distributed applications is presented. As the size of the system grows and the PMU data becomes available with faster data rates, the centralized operation and control will no longer be scalable. To address this need, a distributed architecture for communication, computation and control is described. A method is developed to determine the parameters to simulate a communications system for a smart grid starting from the power network configuration and the knowledge of the measurement data and the on-line applications. In designing the smart grid infrastructure for a particular power system, the assumptions should reflect the actual design parameters of the communication infrastructure. Such a simulation tool can be used to develop, design and test the performance of the communication system to determine the bandwidth and latency requirements. We believe that given the actual applications and their precise data requirements further improvements in the results can be obtained on a case to case basis. For example further reduction in bandwidth and latency is possible by using multicast routing and packet tagging. In a particular scenario we may not send all the traffic to the control center and SPSs can be located to take advantage of the distributed data bases. Slower EMS applications running in the control center can then source the required data from the distributed databases using middleware architecture like Gridstat. These improvements have to be made based on individual network needs.

This is a system specific study based on certain design assumptions. However the simulation methodology is generic and useful for design of communication infrastructure. Propagation delay changes with network topology, whereas, queuing delay and transmission delays change with the communication bandwidth. Average link bandwidth needed for smart grid applications should be in range of 5-10 Mbps for communication within one control area and 25-75 Mbps for inter control center communications. Using meshed topology delays can be contained within the 100ms latency requirement satisfying all applications. Also with packets traversing just 8-10 hops processing delays at routers should not be a problem.

For the case when the latencies are increasing beyond a feasible value, it is shown that distributed communication architecture with local control centers is a better choice.

The effect of communication latency on the design of wide area controllers is also demonstrated with an example of a damping controller. It is observed that if adequate bandwidth is not used for acquiring remote signals for closed loop control, the delays in getting the signals increase and the performance of the controller deteriorates to an extent that the controller is no longer able to stabilize the system after a disturbance.

The architecture and the process described in this work aim towards development of a holistic approach for design of new decentralized and scalable architectures using distributed applications and distributed databases for wide area control of future smart grids.

7 Future EMS Implementation Stages

The most difficult question how to proceed with implementing new EMS solutions is related to the transition from legacy designs to new designs. This is not a trivial process since an EMS deployment may cost over 100million, so such systems do not get upgraded frequently. This section is devoted to the development of future EMS implementation strategies.

7.1 Future EMS Deployment Architecture

The current EMS deployment architecture follows a circular strategy as shown in Figure 29. The "circular" strategy assumes that the life-cycle of the EMS system starts with a specification and ends with decommissioning of the entire system with no major design updates during the life-cycle. This "circular" approach allows only minor upgrades in its life cycle leaving no room for major upgrades. This project proposes "spiral" architecture for EMS deployment shown in Figure 30. This strategy is highly recommended since it allows major design upgrades to be done at any time and hence the system life-cycle never ends but gets prolonged as the updates are made. The key to this new deployment strategy is to have an interoperable design that conforms to the interoperability standards framework shown in Figure 31. The discussion of the interoperability requirements is well documented in the reports from the GridWise Architecture Council (GWAC) that also maintains an elaborate website on this issue.

Figure 29 "Circular" EMS deployment

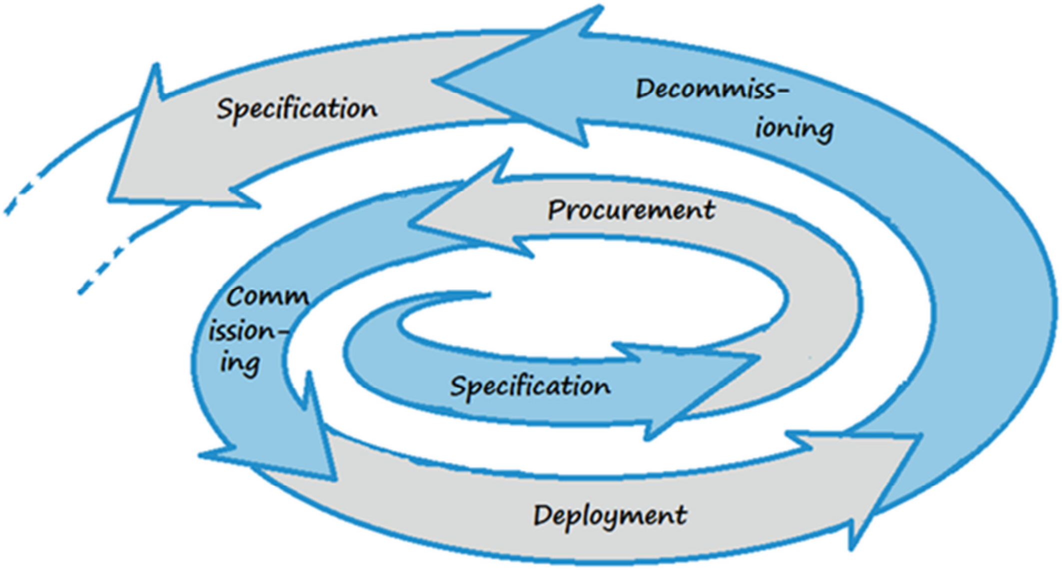


Figure 30 “Spiral” EMS deployment

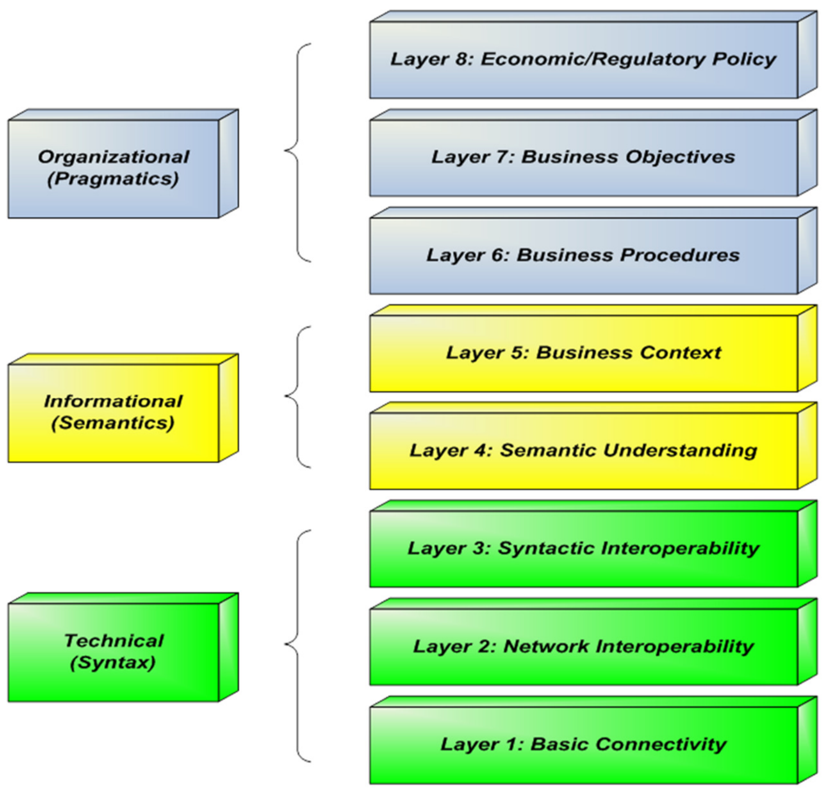


Figure 31 GWAC interoperability stack

In the context of the EMS deployment and related life-cycle approaches, the following three design steps have been well recognized:

- *Improvement of existing functions*. This approach uses an existing infrastructure including SCADA and EMS functionalities but it provides for improved performance. Examples of such approaches are improved state estimator, topology processor, alarm processor, etc. To achieve such improvements only the additional data management functions need to be implemented, which is relatively straight forward.
- *Addition of new functions*. Adding new functions requires an open system design so that functions developed by various vendors may be incorporated in the legacy EMS solution. Such new developments are primarily related to new data analytics such as economic alarms, detection and mitigation of cascades and automated fault analysis as discussed earlier.
- *Green field design*. This, obviously, is a totally new EMS design that is based on innovative IT solutions for distributed processing, enhanced cyber security, high speed/ capacity communications, very versatile visualization and most of all functionality that can cover demanding needs for controlling intermittent renewable generation, coordinating interaction between transmission and distribution operation, and enhancing power system resilience to weather disasters or physical attacks.

What remains to be defined for future EMS developments is the value proposition of all the mentioned changes. This type of analysis is dependent on many factors that are tied to specific utility circumstances, so general rules may not be easy to develop.

7.2 New Functionalities

The purpose of this sub-section is to illustrate how the proposed EMS design enhancements may lead to the development of new functionalities and operator support tools that are not feasible with the legacy solutions. This discussion reinforces the reasons and benefits of pursuing the proposed changes in the EMS design requirements.

7.2.1 Detection and Mitigation of Cascading Events

A monitoring and control scheme for detection, prevention and mitigation of cascading events which coordinating the system-wide and substation-wide algorithms are proposed in [20]. Figure 32 shows the conceptual interaction scheme. The proposed system-wide monitoring and control tool is intended for installation at the control center. The system tool consists of the routine and event-based security analyses based on the power flow method and topology processing method, along with the security control schemes for expected and unexpected events. The local monitoring and control tools intended for installation at local substations consists of an advanced real time fault analysis tool and a relay operation monitoring tool utilizing neural network based fault detection and classification algorithm (NNFDC), synchronized sampling based fault location algorithm (SSFL), and event tree analysis (ETA). The advanced on-line fault analysis tool will detect the disturbance by analyzing local measurements. Once the disturbance is detected and classified, event tree analysis process will be invoked to validate relay operations.

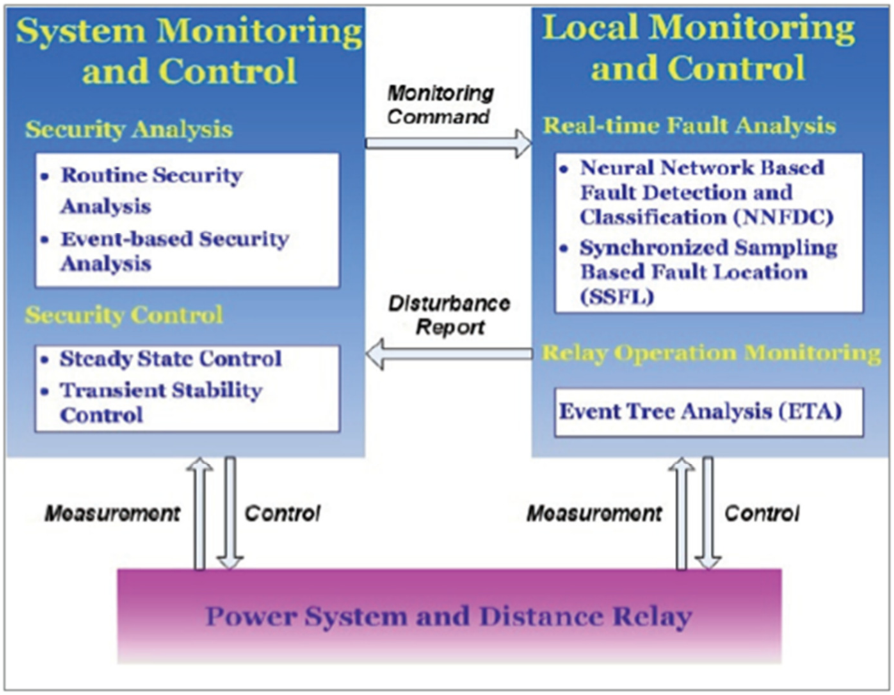


Figure 32 Detection and mitigation of cacscades

The combination of the two algorithms performs a more accurate fault analysis than conventional relays do. This provides a reference for monitoring and verification of the distance relay operations. The substation-based solution can provide the system-wide tool with local disturbance information and diagnostic support so that the system-wide tool can utilize local information to take better control action to ensure the secure operation.

The Figure 32 points out to the immediate needs, a) monitor system conditions using synchronized phasor measurements to assess system disturbances that may result in major system contingency. b) monitor protective relay operation using synchronized samples from two (all) ends of a transmission line to assess whether the lines switched out are actually faulted or not. The consequence is that it is feasible to anticipate unfolding contingencies and monitor the impact that they may have on the system. As a result, the operators would be able to establish the fact that a cascade has been initiated and react accordingly to arrest cascade, which is not possible today.

The above discussion assumes that the transient stability assessment is done online. Fast transient stability assessment using synchrophasor measurements using advanced high computing facilities is one application that can be envisioned in the near future. Small-signal oscillation detection and control applications are currently offered in the market as standalone applications which can be incorporated into EMS in the near future.

7.2.2 Enhancing the View of the Power System

Based on the mentioned improvements in the alarm processor, topology processor, and fault location, and taking into account the new capability to detect and mitigate cascading events, a new set of monitoring capabilities may be offered to the EMS operators as illustrated in Figure 33. The following visualization capabilities are envisioned.

Equipment Model View

In our proposed GUI system, various power systems' equipment is modeled and presented to operators through user interfaces. Currently the modeling of two types of devices has been done: Transmission Tower and Circuit Breaker.

Aerial View

Once the fault location is calculated it is very important that the details are effectively presented to maintenance crew. The Aerial (satellite) View module translates results from fault location report files into a view of the corresponding faulted zone. Through this module it is possible to see physical environment of the faulted area, as well as the behavior and status of equipment involved in the fault event.

Electrical View

This is another independent module integrated in the visualization tools. The Electrical View GUI is used to display the electrical measurements in the system on the one-line diagram, which includes the visualization of entire system connection, power flows, alarms, etc.

Topological View

The power grid topology describes connectivity of the various components in the power system. In order to process retrieved fault event recordings, they must be related to a

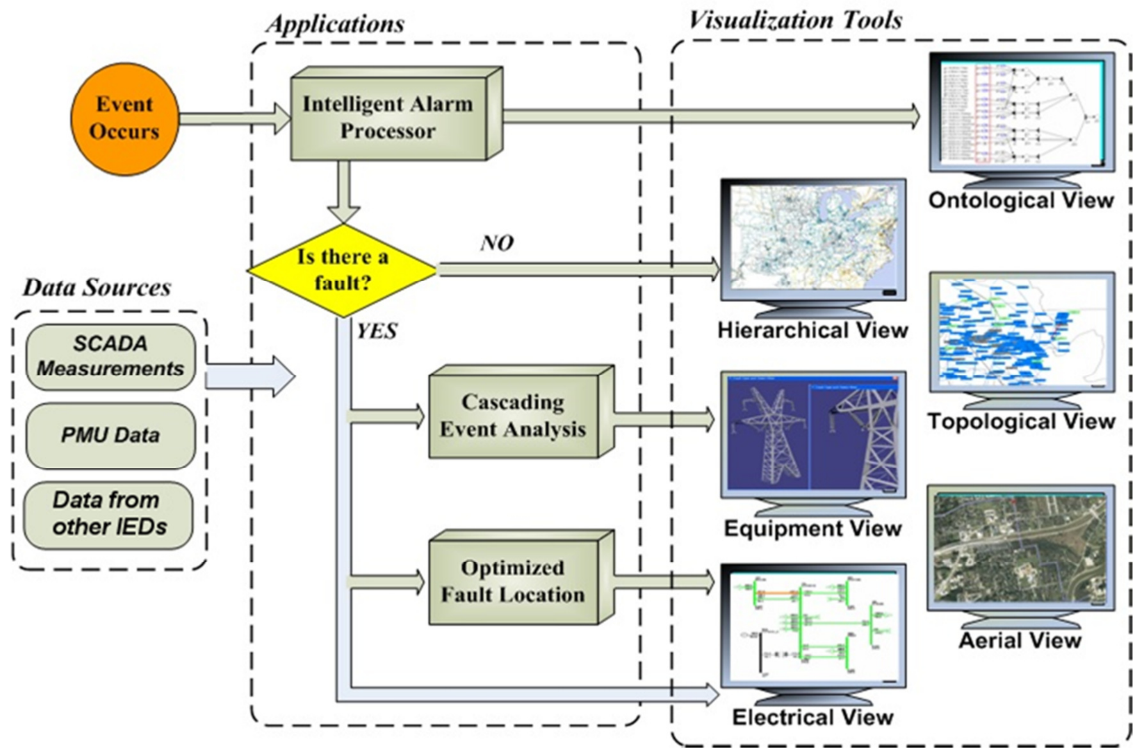


Figure 33 Enhanced view for EMS operators

specific breaker/switch position from which they are measured and the information how the measurement positions were interconnected at the time of the fault occurrence needs to be known. Therefore, the system topology must be visualized.

Ontological View

The Ontological View module relates to the application of intelligent alarm processor. The GUIs incorporated in this module display how the Petri Net Logic is executed, i.e. how the irrelevant alarms are removed and how the essential alarms are extracted. This can provide operators a comprehensive understanding of the causes and possible effects of the event.

Hierarchical View

When system is in a normal state, real-time visualization and monitoring of the power flow and related operation are necessary. The graphical software can import real-time data by connecting to data sources that enable users to perform supervision and visual analysis of power system operations. The Hierarchical View module is used to track system behavior in normal state. Real time data are obtained from SCADA database. We are using PI Historian as an example since it is widely used in the industry and because it is a time-series database designed and optimized to quickly receive, store and retrieve time-oriented data. The database could efficiently store numerical and string data, and can accommodate both small and large quantities of data for extended periods

The EMS operator view concept illustrated in Figure 33 reflects some new EMS design features not available in legacy EMS designs but certainly expected in the next generation designs:

- *Underlying GPS time synchronization and stamping* allows spatiotemporal correlation between field data and power system models assuring correct assessments of the dynamic states and transitions
- *Improved data acquisition system* allows detailed monitoring of the evolving system dynamics using synchrophasors and abrupt transient changes using time domain samples
- *Improved functionalities* allow quick understanding of the cause effect relationship among the alarms and accurate location of faults leading to detection and mitigation of cascades
- *Improved hierarchical views* of the equipment, electrical circuits, geospatial displacement, and network topology allows full understanding of the system conditions and targeted control action

If one compares the new capabilities illustrated in Figure 33 with the capabilities of the original EMS design one can certainly note improvements in operator's ability to view and operate power system. Dedicated data mining and analytics tools to explore the trends in the data etc. can be provided as a package in future EMS designs in the near future.

7.2.3 Matching Data and Models

With the increase in data volume and quality, the question opens whether the decision making process that operators go through can gain any benefits from this data improvement. Recent studies have shown that the process of matching data to hypothesis models at various levels of complexity can help the decision making process [3]. In such cases the decision making process is enhanced with cause-effect analysis embedded in the match between the data and model. This process of extracting knowledge from data, often termed Data Analytics, is shown in Figure 34. (data management) and Figure 35 (type of data that may be processed).

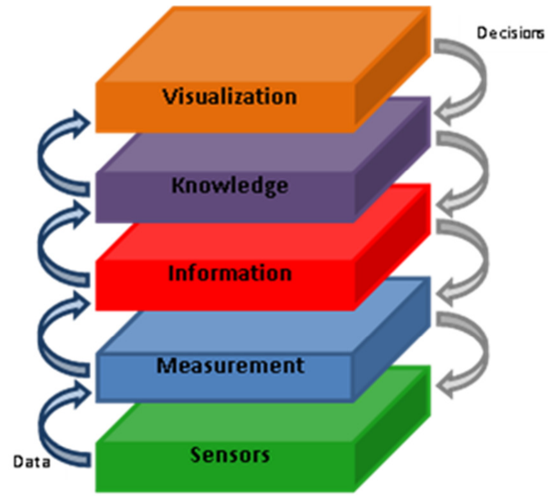


Figure 34 Data management steps

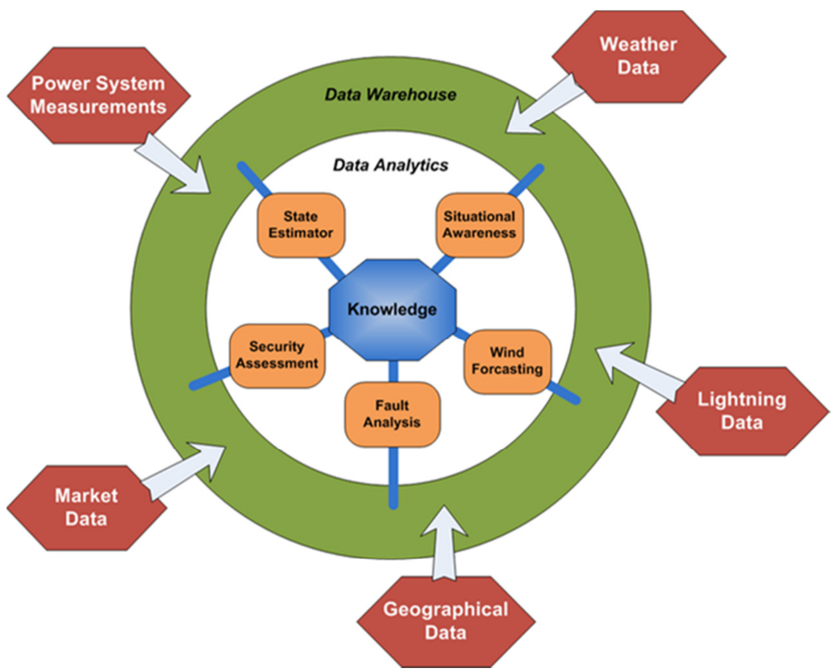


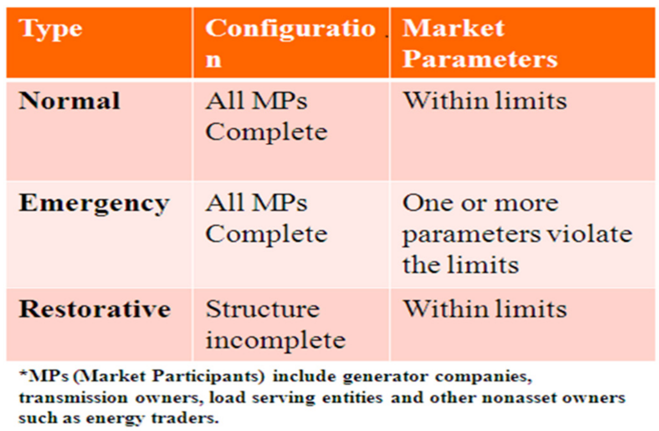
Figure 35 Diverse data used for new data analytics

State estimator does match the models with the measurements from RTUs. Incorporation of synchrophasor data into state estimation models along with the SCADA scans improves the speed of state estimation and provides better visibility of the power systems. There has been very little advancement in matching models used across various tools like dynamic security assessment tools, power system protection design tools etc.. With the new data additions it is possible to update dynamic models very frequently. The EMS in the near future has to incorporate separate functions to dynamically update, match models and manage the models across various tools used in the operations.

7.2.4 Tying Physical and Electricity Market States

With the proposed changes in the EMS design requirements, one can expect further improvements in operator's ability to correlate status in the electricity market operation and operation of the physical power system. An illustration of the market states that correspond to the power system states shown in Figure 1 is given in Figure 36.

As an extension of the proposed correlation, one can develop new concepts in operating the system by tying together the high fidelity alarms with the economic constraints. A recently proposed concept of "Economic Alarms" allows this correlation to be established and explored to for the benefits of market and system operators [17]. The new economic alarm EMS functionality is shown in Figure 37.



Type	Configuratio n	Market Parameters
Normal	All MPs Complete	Within limits
Emergency	All MPs Complete	One or more parameters violate the limits
Restorative	Structure incomplete	Within limits

***MPs (Market Participants) include generator companies, transmission owners, load serving entities and other nonasset owners such as energy traders.**

Figure 36 The electricity market states

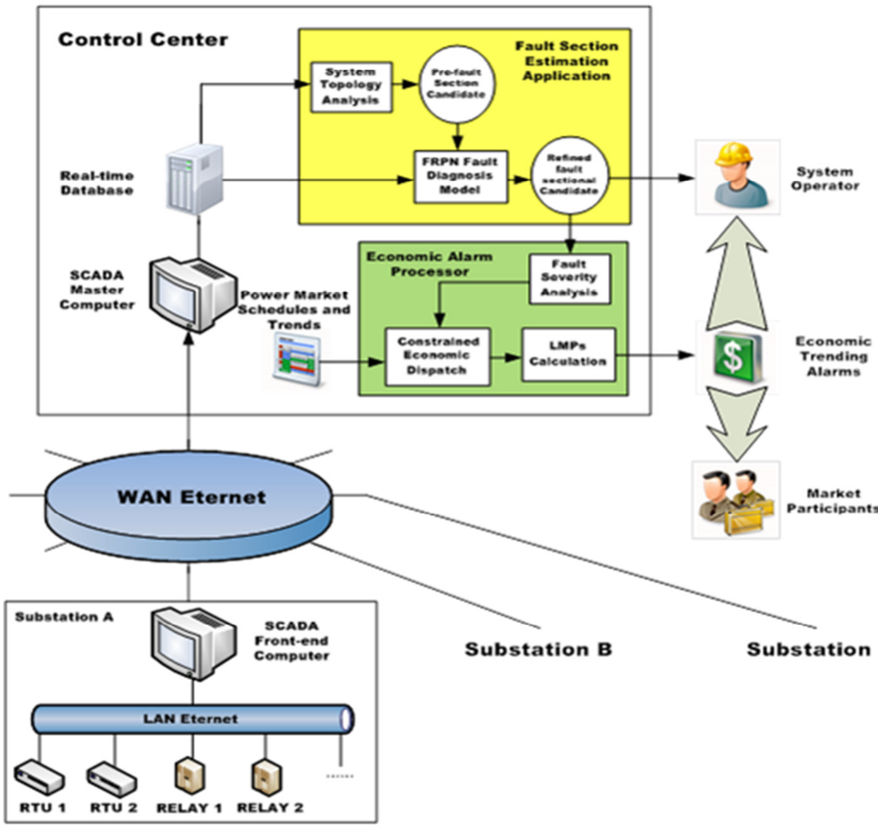


Figure 37 Intelligent economic alarm processor

As illustrated, this new EMS functionality ties together a cause-effect capability of the intelligent alarm processor enhanced with spatiotemporal measurements from all IEDs with the capability to better control and mitigate electricity market consequences caused by major physical disturbances in the system. Using this example, the new EMS design requirements can be summarized as follows:

- Improved data acquisition infrastructure provides better monitoring of the power system states
- As a consequence, operators are able better track and control changes in the power system operating states
- This creates ability to better match system and market conditions under major disturbances
- It also creates an ability to better respond to cascading events by arresting cascades early on

7.3 Green Field Design and Application Improvements

7.3.1 Online Protection Adequacy Checking and Relay Testing

The addition of non-operational data to SCADA data base allows seamless remote access to protective relays settings. Currently utilities maintain a separate protective relay settings data base. Protective relays miss operation is a common cause of many black outs. If the control center operator has a better picture of proximity of the current operating condition to the protection margins then he can make better judgment and decisions. Online testing of the digital protective relays without disconnecting them from the operation have been reported in the literature recently in [52]. Assuming the technology can be matured in near future, Figure 38 explains a procedure that can provide the operators, information about the system components whose protective relays are at the verge of the protection margins. The tool is envisioned to be able to test the critical relays and alert the maintenance if the relays fail during the tests. The tool can be used in day to day operations as well as look-ahead scenarios by using weather forecast and GIS mapping of the transmission assets under threat. One can also identify the assets which can lead to cascade events.

7.3.2 Dynamic System Integrity Protection Schemes (DSIPS)

System integrity protection schemes (SIPS) or remedial action schemes are very important offline tools designed to save large power systems from critical conditions [53]. The system operating condition is monitored for various contingencies and operating scenarios for which the SIPS are designed. Whenever the conditions occur the SIPS will be activated. The SIPS are usually designed using offline simulated conditions

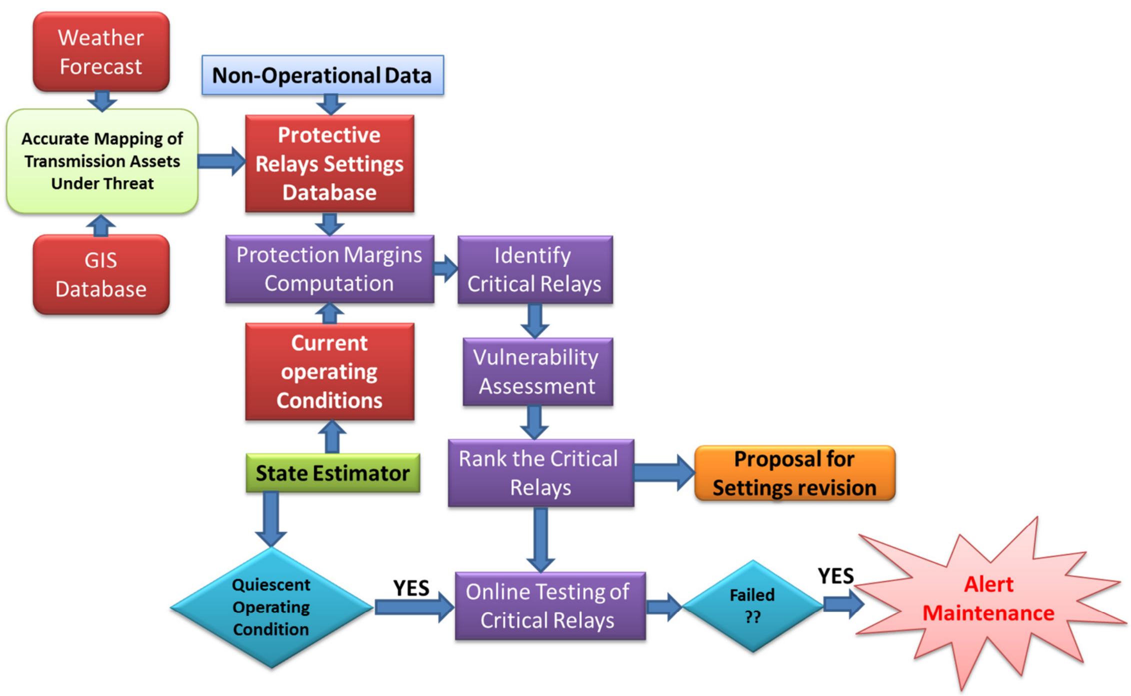


Figure 38 Online protection adequacy checking and relay testing application

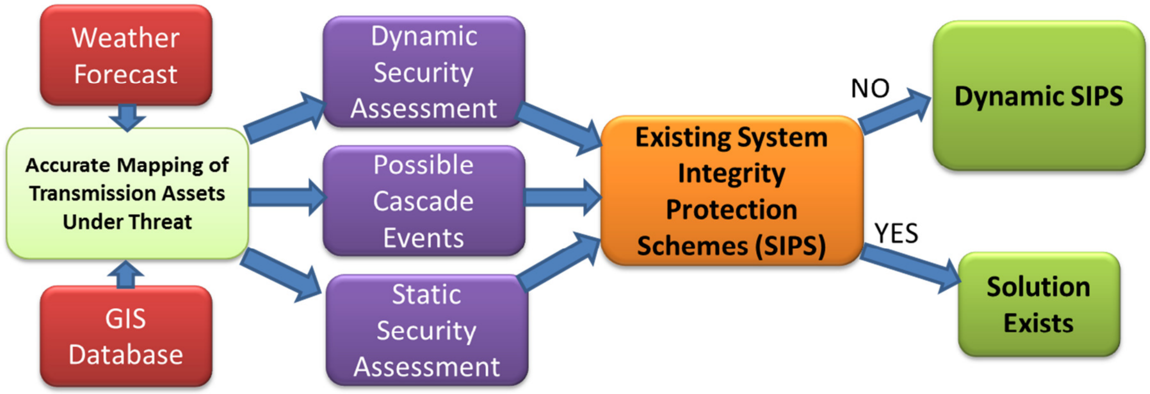


Figure 39 Dynamic system integrity protection schemes

for various assumed scenarios. As power systems are highly dynamic in nature, especially with the high penetration of renewables, there is a need for the design of dynamic system integrity protection schemes (DSIPS). With the proposed data integrations it is possible to determine the state of the system accurately, with better stability and security margin predictions. Figure 39 shows an approach for DSIPS implementation. With the accurate weather data and GIS transmission asset mapping it is possible to identify the transmission assets under threat for any forecasted natural disasters. Dynamic security assessment and static security assessment can be performed to identify the critical assets. The contingencies which are not covered by the existing SIPS schemes can be analyzed for designing Dynamic system integrity protection schemes. The DSIPS implementation requires sophisticated communications architectures for precise control.

7.3.3 Renewable Coordinator: Enabling Renewables, Electric Vehicles and Storage Grid integration

Advancements in the solar and wind energy technologies have paved a way for large installations across the world [54]. Grid integration of large wind and solar power plants introduce uncertainty in power system operation due to their high variability. Proper planning of hour to hour and day to day operations becomes a challenging task with the increase of bulk power transfers from the renewables. Integration of bulk renewable energy sources impacts real-time markets, hour-ahead, day-ahead markets and ancillary markets. There is a need for introducing new market applications which allow seamless integration of bulk renewable sources. The key success of these applications lies in the uncertainty prediction in the forecast models. Reference [54] proposed several approaches to model the uncertainty and outlined methods of integrating these models into economic dispatch and unit commitment processes. It has been shown that advanced control concepts allow bulk wind plants participation in ancillary power and reactive markets [55]. Recent advances in Vehicle to grid technologies (V2G) also allow electric vehicles participation in ancillary markets [56]. Current EMS applications do not provide seamless integration of renewables and EVs in market participation and ancillary services.

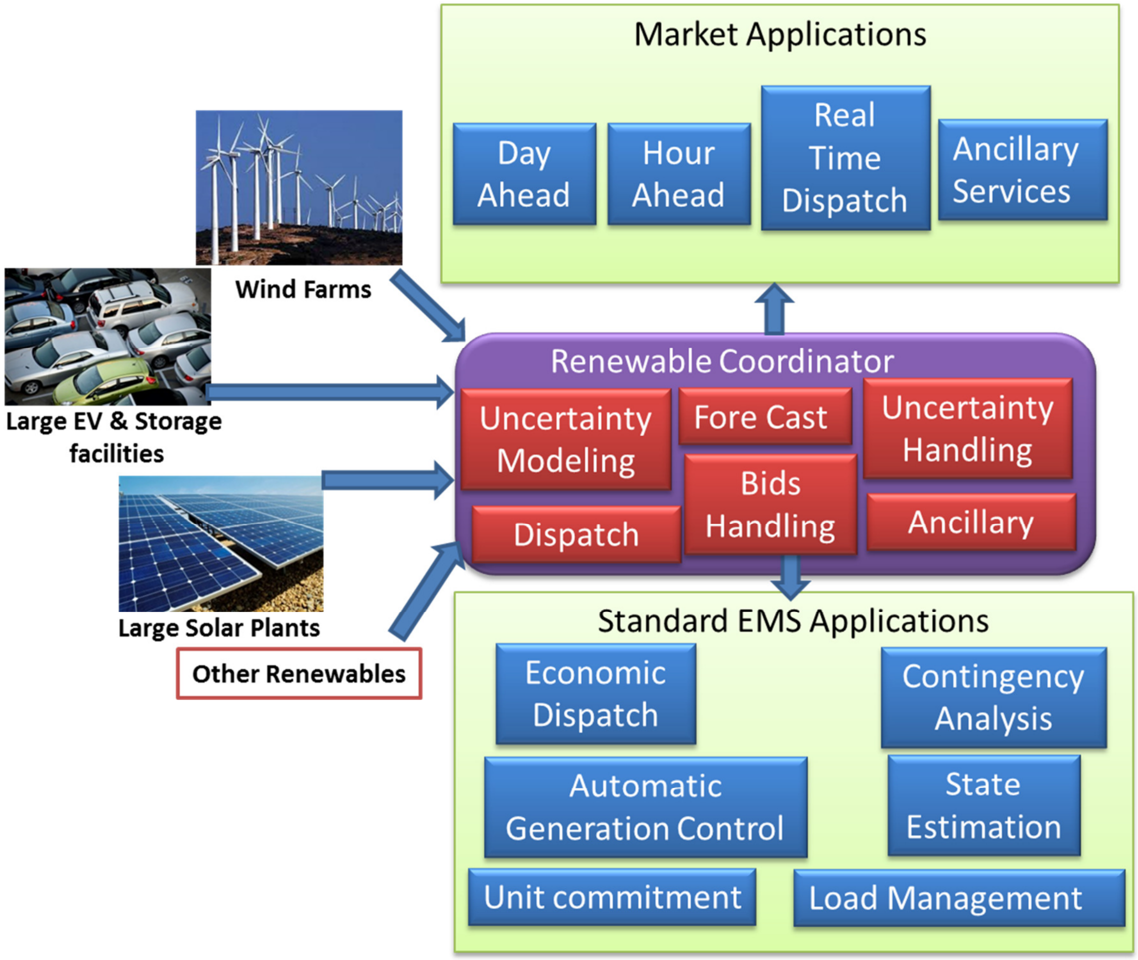


Figure 40 EMS application for seamless integration of renewables, EVs and storage

The existing market functions and standard EMS functions like Economic dispatch, and Unit commitment have evolved over the years with lot of operating experience. Changing the standard application routines may not be appealing to the industry as they have established high credibility. So it is envisioned that renewables integration is achieved using a new EMS application called Renewable Coordinator with minimal changes to the legacy components so as to retain the credibility of the legacy components as shown in Figure 40. This coordinator performs various tasks like forecasting, uncertainty modeling, renewable dispatch, bids handling and uncertainty handling etc. The basic idea behind this application is that even though the renewables have high variability the legacy EMS solutions see it as a conventional generating station. When the renewables are looked at as independent sources then the variability is significant but when they are looked as a collective source then the variability will drastically reduce. This phenomenon is very well understood in practice in distribution transformers (DT) loading. Even though the load curve of individual customers contains high variability the collective load curve of the DT doesn't exhibit high variability. If the renewables are handled using renewable coordinator function in EMS the need for changing the legacy solutions will be very minimal.

7.3.4 Online Coordinated Oscillation Damping and Voltage Controllers Tuning

There have been significant research efforts in the past few years on wide area power system damping and voltage controllers using PMU measurements [12]. In a typical power system there exist several oscillatory modes in the range of 0.1 to 2.5Hz. The inter area frequencies in the range of 0.1 to 0.8Hz are very critical. At any time there may be more than two machines participate in these modes. Out of the participating generators only few will contribute positively to the modes and others contribute negatively. Control actions from the negatively contributing generators will be ineffective and may worsen the damping properties. So there is a need to identify the generators which can aid to the damping of oscillatory modes. In other words controllability of the modes w.r.t the damping controller's location in the network needs to be assessed [57]. Similarly, under high loading conditions, if the reactive power requirements are very high, the voltages will drop. In such situations the voltage controllers like STATCOMs & SVCs may not help in improving the overall voltage profile because the reactive power generated by them will be locally absorbed. In such situations not just the voltage control based on injecting reactive power but also the real power injections need to be coordinated to maintain over all voltage levels within safe limits. Current real power dispatch models include voltage controllers like STATCOM, SVCs etc. But the control parameters' tuning is done for pre-determined range of operating conditions. The voltage controllers need to be tuned to the re-dispatched operating condition for better performance. The oscillation damping and voltage controllers are handled separately. However, as the real power re-dispatch alters the damping properties of the system the damping controllers need to be re-tuned.

There is a need for coordinated tuning of voltage and damping controllers online for better voltage and damping properties across the system based on real power dispatch.

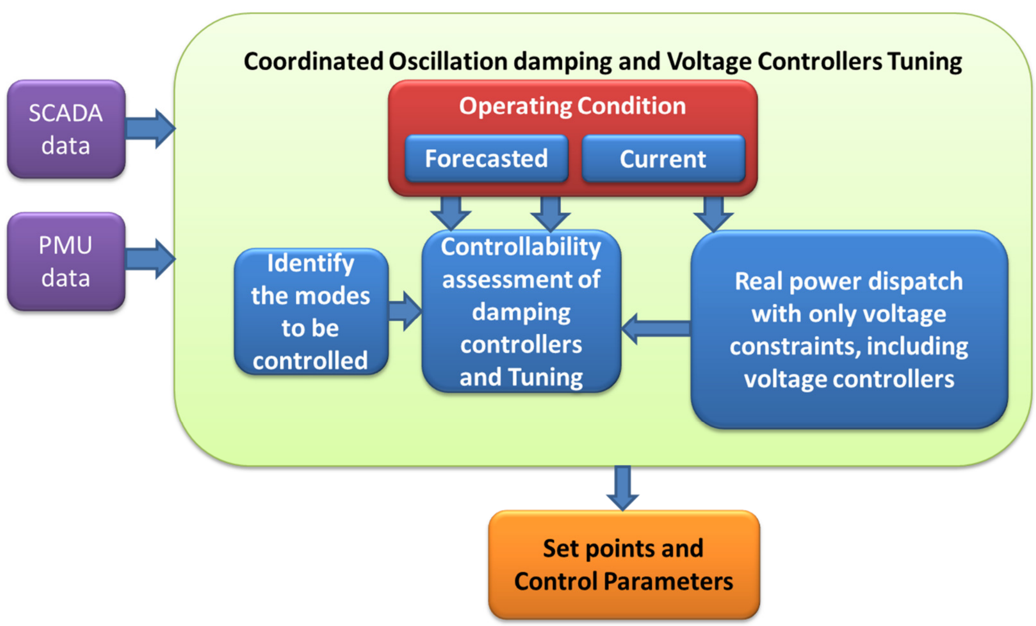


Figure 41 Online coordinated oscillation damping and voltage controllers tuning

Measurement based tuning approaches proposed in [58] can be effectively used for online tuning of the power system stabilizers. Figure 41 shows an approach for achieving the coordinated tuning of oscillation damping and voltage controller's parameters based on the real power dispatch. The application is envisioned to function both in real-time and look-ahead scenarios.

7.4 Conceptual Future EMS Design

Energy control centers become the most important assets to be protected from the national security threats like terrorist attacks, natural disaster threats like Tsunamis, earth quakes etc. Energy control center commissioning is economically and technically involved process, it is highly impossible to tolerate their loss due to the above mentioned threats. Future designs should keep this as the priority in their design plans. As discussed in Section 7 the designs should be open ended with unlimited life cycle. To achieve a near indestructible energy control center, a conceptual future EMS design is proposed in this section.

In future high performance cloud computing and high speed cloud storage technologies are envisioned to be economical enough to be used in power system control centers. As the measurement technologies are based on digital computations, a next generation RTU with embedded relaying functions (can be called a next generation relay) is envisioned in the future with a fusion of various measurement technologies needed for power system monitoring and control like weather, thermal, lightning, PMU, DFR, SER etc. Assuming

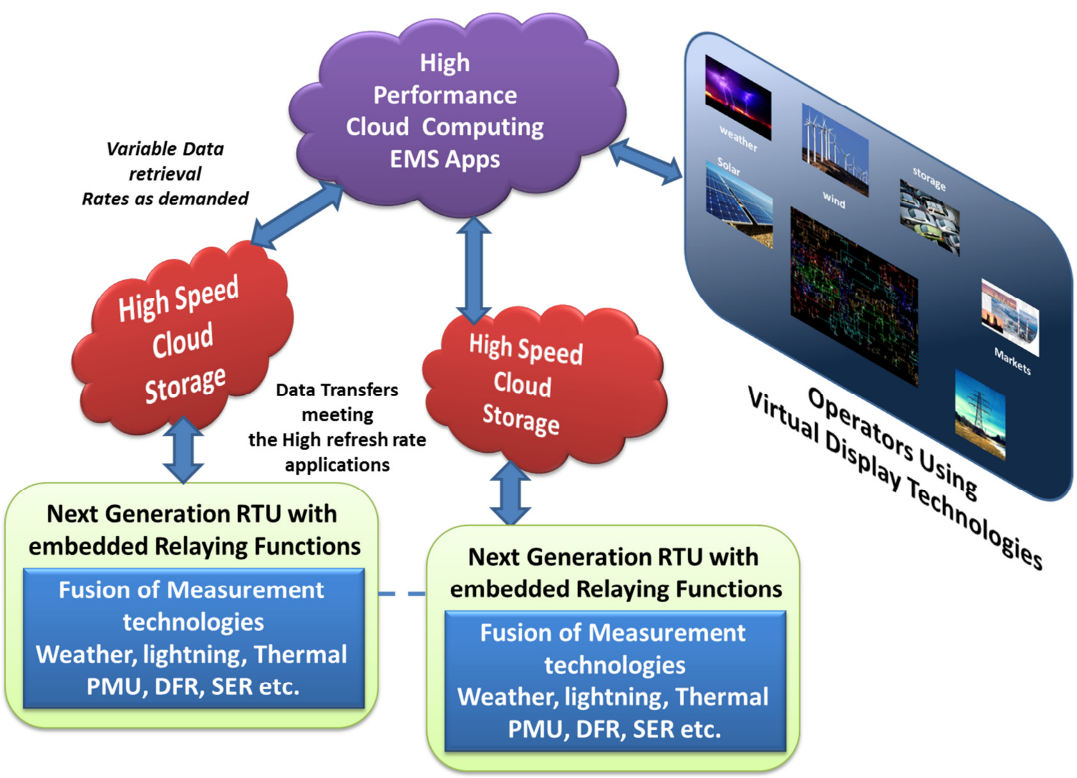


Figure 42 Virtual EMS Design Platform

that the virtual display technologies shown in Bollywood movies and conceptual Google glass technologies come to reality and becomes cheaper a virtual EMS design for futuristic control centers is shown in Figure 42. This is called as Virtual EMS Design Platform.

The vision is that there won't be too many measurement devices in the field for various purposes. A single next generation RTU with embedded protection functions performs all types of measurements and control functions. The device is capable of delivering data at varied sampling rates demanded by the EMS application software and uploads to the cloud storage almost instantaneously. The entire EMS computing functionalities are assumed to be residing on high performance cloud computing platforms which can be accessed by the operator on virtual 3D display technologies. Essentially the physical infrastructure is just limited to the next generation RTUs and everything else will reside on the cloud. If such a control center is built then it can be accessed by the operators from anywhere with ease. This kind of EMS control center cannot be destroyed physically by any threats described above.

7.5 Conclusions

Future EMS implementation stages are elaborated in this section. A "spiral" architecture is envisioned to be a better approach for EMS deployment in order to embrace the new technology advancements with an open ended life cycle. This architecture allows major upgrades as when required. Three design steps are identified in this section for EMS implementation. The first design step allows significant improvements to legacy applications. The second design step allows addition of new functionalities to the legacy EMS systems through open deployment strategy. Third design step called green field design envisions adaptation of innovative IT and communication technologies for a completely new EMS design. This section introduced four exemplary new EMS functionalities for second design step and four green field design applications. A Virtual EMS Design Platform is proposed in this section as an effective alternative to guard against natural disasters and terror attacks. This platform envisions development of a next generation RTU with fusion of various measurement technologies and relaying capabilities. This RTU is expected to eliminate extensive communication infrastructure and display infrastructure harnessing the potential of cloud based storage & high performance computing with virtual 3D display technologies.

8 Conclusions

The continuing changes in sensing, measurements, communications and computation have now reached a stage where the digital data acquisition architecture that has served the monitoring and control of the power grid for over half a century requires a fundamental change to fully utilize the new technologies and realize the promise of a new generation of applications. Although the new applications will evolve over time, they are dependent on this new architecture requirement and the various considerations that will influence this design are discussed in this report.

The time stamping and increased frequency (fidelity) of the measurements are fundamental differences in the data acquisition. So is the ability to process the data locally at the substation instead of all data processing centralized at the control center. This changes the communication requirements and points to a more networked high-bandwidth architecture rather than a star configuration. This further indicates that a decentralized database and applications that could be distributed may be considered going forward, but such approaches need much more elaborate set of application requirements that are outside the scope of this report.

The purpose of this report was not to propose a specific new configuration of the next generation EMS but to raise the various trends that will surely affect the new architecture that will evolve. In support of the new trends the report has clearly indicated limitations of the data acquisition infrastructure in use today and illustrated how the new design features may affect existing EMS functionality and offer opportunities for development of new functionalities.

As a result of the discussion, the following conclusions are drawn:

- After 50 years of EMS legacy design being used, the industry is facing a need for a new EMS design. This is caused by the existing EMS design not being able to respond to the need to monitor, protect and control power system as new developments in the power system introduce new dynamic behaviour. The desirable features are: integration of field data, introduction of new decision-making tools based on data analytics for knowledge extraction, and flexible implementation architecture that allows transition from legacy to new designs

- Consequences of the mismatch between legacy and new EMS design requirements affect data acquisition, data management and communication architecture. Integration of field data i.e. integration of IED data base and SCADA data base is the key step for improving operational visibility of the system. Consistent semantics modelling is essential for seamless integration of IED and SCADA databases. This report points out that such improvements can be gained in the areas of intelligent alarm processing, automatic fault location and topology processing.

- The future EMS design requirements should consider the temporal and spatial attributes of IED data sources. This report highlighted important temporal considerations which require some special hardware implementations. Spatial considerations are shown to be very important for information exchange, models representation and applications. The huge volumes of data generated by the new IEDs pose several challenges to the communication architecture.

- The future EMS communication architecture has to cater all the applications as and when needed with required speed and reliability. Propagation delay changes with network topology, whereas, queuing delay and transmission delays change with the communication bandwidth. Average link bandwidth needed for smart grid applications should be in range of 5-10 Mbps for communication within one control area and 25-75 Mbps for inter control centre communications. Using meshed topology delays can be contained within the 100ms latency requirement satisfying all applications. Also with packets traversing just 8-10 hops processing delays at routers should not be a problem.

- For the case when the latencies are increasing beyond a feasible value, it is shown that distributed communication architecture with local control centres is a better choice. If adequate bandwidth is not used for acquiring remote signals for closed loop control, the delays in getting the signals increase and the performance of the controller deteriorates to an extent that the controller is no longer able to stabilize the system after a disturbance.

- The implementation of future EMS design needs to take place in stages allowing seamless transition from legacy solutions to new designs through use of interoperability standards. A "spiral" architecture is envisioned to be a better approach for EMS deployment in order to embrace the new technology advancements with an open ended life cycle. This encompasses improvement in existing functions, introduction of new functions and eventually a green field design that supersedes previous solutions.

- A Virtual EMS Design Platform is proposed in this section as an effective alternative to guard against natural disasters and terror attacks. This platform envisions development of a next generation RTU with fusion of various measurement technologies and relaying capabilities. This RTU is expected to eliminate extensive communication infrastructure and display infrastructure harnessing the potential of cloud based storage & high performance computing with virtual 3D display technologies.

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Glossary

A/D: Analog to Digital	15
AVC: Automatic Voltage Control	2
BPL: Broadband over Power Line	29
CB: Circuit Breaker	11
CBM: Circuit Breaker Monitor	14
CBR: Constant Bit Rate	29
CIM: Common Information Model	2
DDR: Dynamic Disturbance Recorder	7
DFR: Digital Fault Recorder	ii
DG: Distributed Generation	2
DO: Data Object	16
DPR: Digital Protective Relay	ii
DSIPS: Dynamic System Integrity Protection Scheme	66
DSM: Demand Side Management	8
DT: Distribution Transformer	67
DUSM: Dynamic Utilization of Substation Measurements	13
EEM: Enterprise Energy Management	2
EMS: Energy Management System	ii
EPRI: Electric Power Research Institute	10
ERD: Event Recording Device	7
ETA: Event Tree Analysis	58
EV: Electric Vehicle	66
FL: Fault Location	16
FRPN: Fuzzy Reasoning Petri Nets	10
G2G: Gateway to Gateway	37
G2S: Gateway to Server	37
GA: Genetic Algorithm	12
GIS: Geographic Information System	20
GPS: Global Positioning System	7
GUI: Graphical User Interface	60
Gw: Gateway	37
GWAC: GridWise Architecture Council	56
IAP: Intelligent Alarm Processor	10
ICCP: Inter Control Center Protocol	41
IEC: International Electrotechnical Commission	16
IED: Intelligent Electronic Device	ii
IEEE: Institute of Electrical and Electronics Engineers	32
IT: Infornation Technology	iii
LAN: Local Area Network	21
LD: Logical Device	16
LN: Logical Node	16
MTU: Maximum Transmission Unit	29
MW: Mega Watt	2