On the Complexities of Interdependent Infrastructures for Wide Area Monitoring Systems

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Abstract—**Electric power systems (EPS) evolved over years from local independent entities towards large interconnected networks monitored and controlled by sophisticated ICT technologies, and which, eventually will be transformed into Smart Grids where also distributed energy sources, storage, electric vehicles and appliances will be active components of the system. Thus, the scale of complexity involved in present and future power systems architectures is significantly greater than in the past. This paper aims to discuss the interdependency between electric power and communication systems under the system of systems concept. The nature and scale of interdependency between these two critical systems is then further analyzed using an example of disturbance on communications and observing the cascading effects on the power system's monitoring process. Specifically, the impact on the state estimation accuracy is investigated, as a result of a communication node failure, which is responsible for transferring Phasor Measurement Unit (PMU) data to the control center.**

Keywords-[complexity, critical infrastructure, PMUs, state estimation, system of systems]

I. INTRODUCTION

The majority of power systems were initially designed to supply electricity at a local or regional level. However, over decades they expanded beyond country borders resulting in large interconnected electrical grids. Thus, todays' electrical power grids consist of several and heterogeneous components, all connected through complex electrical networks [1]. Private and public utilities jointly operate in interconnected power grids, thus increasing the reliability of the whole system, but also generating market opportunities. This interconnection evidently improves the reliability of each member utility because any loss of generation can be transparently covered by the neighboring utilities. At the same time, it is evident that this interconnection increases the complexity in modeling the electrical power systems (EPS).

Real-time monitoring, control and operation of such large systems pose a number of challenges which might be a result of the unavoidable and increased coupling of the individual components involved in modeling EPS, together with their nonlinearly and continuous interacting behavior. Behavioral consequences of the components-oriented nature of these systems may range from qualitative differences when large numbers of sub-systems interact and interoperate , the so called "more is different" concept, to modeling and simulations challenges in calculating response functions or influence coefficients [2]. However, determining the effect on one part of the system that results from a disturbance introduced at another is not a trivial task especially in nonlinearly coupled sub-systems such as EPS. On top of the interconnection growth of the electrical network, integration with other infrastructures such as communication networks, ICT systems (hardware and software) and satellite networks (GPS) expands the complexity of this infrastructure even further and extends across domains. Understanding the interdependencies between different infrastructures is therefore of critical importance for the correct operation and healthy functionality of the aggregated system and it involves the coordination of several different disciplines.

Despite the fact that there is no unanimous consensus on a definition of complexity, one may argue that there is a consensus on the "emergent property" that characterizes complexity [3]. In modeling contemporary power systems, one may distinguish two main interdependent complexity components: *structural complexity* and *dynamic or operational complexity*. One can further identify several properties for which the structural complexity of EPS modeling is said to increase: <u>heterogeneity</u> of modeling components which crosses over domains (electrical components, information technology components, GPS), <u>dimensionality</u> or complexity by scale (increased number of nodes through interconnections with other neighboring power systems, distributed energy sources, storage and electric vehicles) and <u>scale of connectivity</u> (interactions between components) that requires an increased amount of information necessary to describe the system. Parts of the above terms were borrowed from characteristics of ecological complexity [4]. The second major component of complexity, the dynamic/operational complexity, also known as "behavior (response) complexity" refers to the descriptive behavior (actions) of the system acting in response to its environment. This complexity component is characterized by emergent properties which are "directly related to the dependence of the whole on parts, the interdependence of parts, and specialization of parts" [5]. The nature of complex systems can be probed by investigating how changes in one part affect the others, together with the behavior of the whole. This property will be explored by the example given in Section IV of the paper.

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The remaining of this paper deals with the Smart Grid under the System of Systems concept, providing also a discussion, as well as, an example of interdependency analysis over the principal networks which form the Smart Grid.

II. The Smart Grid as a Complex System of Systems

A. System of Systems and Complexity perspective

A way forward to achieve real-time monitoring and control over the operation of the EPS, thus meeting the needs of the uncertain future, seems to be the driving of the evolution in Systems of Systems (SoS) architectures [6]. An SoS is defined as a collaborative set of systems in which component-systems i) fulfill valid purposes in their own right and continue to operate to fulfill those purposes if disconnected from the overall system, and ii) are managed in part for their own purposes rather than the purposes of the whole [7].

According to IEEE, the Smart Grid is defined as a large and complex system where different domains are expanded into three foundational layers: (i) the Power and Energy Layer, (ii) the Communication Layer and (iii) the IT/Computer Layer. Layers (ii) and (iii) are enabling infrastructure platforms of the Power and Energy Layer that makes the grid "smarter" [8]. It is evident that the viewpoint of IEEE in the Smart Grid concept is representative of the awareness around the interdependent nature of the EPS and the ICT infrastructure.

The Smart Grid concept evolves to include devices that were not previously considered, such as distributed energy sources, storage, electric vehicles, and appliances. Such devices comprise heterogeneous systems that serve as integrated components of the emerging EPS and that have different characteristics and requirements for security, fault detection, protection and metering. It is thus apparent that the contemporary architectures are inefficient due to the increasing demand for greater control of energy usage. The challenge is to build the grounds for an evolving SoS architecture, which will be based on open standard services mechanisms. Such architecture will avoid any hard assumptions made at the design phase, allowing a flexible coupling for:

- Components to be added, replaced or modified individually in case of malfunctions, without affecting the remainder of the system;
- Components to be distributable; and
- Defining interfaces using standard metadata for application developers for use in replacing components.

The evolution of the EPS as an SoS, with the emergence of clear interfaces among component-systems and processes is expected to enhance the ability of controlling and protecting the EPS. Knowing the components and their interactions will definitely increase our ability to detect problems (created by accidental or malicious intervention), characterize them and address them quickly and efficiently.

B. State estimation and synchronized measurements

The aim of the state estimation is to provide an estimation of the network relevant quantities (i.e., bus voltage magnitudes and angles), using available measurements. The measurements that are incorporated in the measurement vector of the contemporary state estimator are the real and reactive power injections, real and reactive power flows and bus voltage magnitudes. The corresponding measurements are expressed using non-linear functions in relation to the power system states and therefore an iterative state estimation scheme is followed. Prior to state estimation, an observability analysis should be executed for ensuring that the EPS is fully observable given the available measurements. A fully observable system guarantees a unique state estimation solution [9].

A unit control error (UCE) signal (the sum of the net interchange flow deviation, deviation from the desired power output and the weighted frequency deviation of the unit) is constructed out of the outputs of the state estimation. The UCE signal is the input for the secondary Automatic Generation Control (AGC) loop which uses an integral feedback controller that regulates the speed (frequency) of generators in real time. Therefore, the critical part of the power system which is directly affected by state estimation is the secondary control loop of the AGC [10].

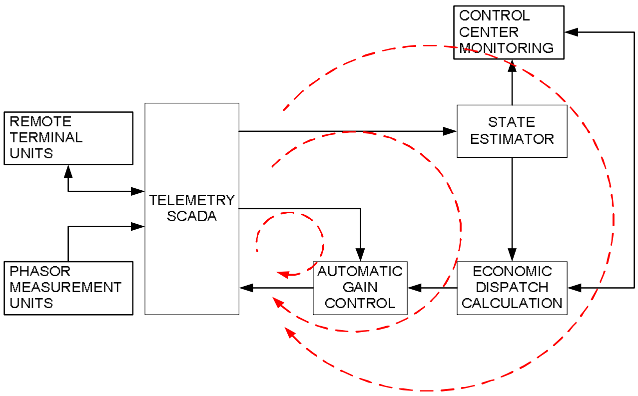

Fig. 1. **Hierarchical control loops in EPS**

Controls associated with a generating unit are numerous and complex (e.g. voltage control, power system stabilizer, primary and secondary AGC). They usually work in a hierarchical manner (Fig.1). For example, at a higher level (economic dispatch block), the reference points for the generator control loops are decided such as unit output, the interchange power, etc. At this level, economy and security of the system is the main consideration. Then, the local control loops are in charge of tracking the reference points. The higher level is performed at a central location, the energy control center. Depending on the sophistication of the particular energy management system, the reference points may be automatically selected by computers or by operators. For example, the reference for the real power output of a unit may be automatically selected by computers based on a real time economic dispatch. Others, for example the frequency reference, may be selected at another central location for a large number of interconnected power systems based on the deviation of the integral of the frequency from an accurate time reference. All of these require that the system conditions are continuously monitored. The monitoring task consists of data acquisition and state estimation.

With the advent of synchronized measurement devices (such as phasor measurement units (PMUs)), it is now possible to measure synchrophasors (voltage and current magnitudes and angles) at sub-cycle sampling rates and transmit this information to the power system control center. Using these new measurements, it is thus possible to enhance the performance and reliability of state estimator. Building on the promising aspects that PMUs bring into the monitoring and controlling applications of power systems, electric utilities are installing PMUs incrementally. As power systems are now partially observable by synchronized measurements, a hybrid state estimator that uses both conventional and synchronized phasor measurements for estimating the states of the system seems to be an appropriate solution. The incorporation of synchronized phasor measurements has been shown to improve the performance of the hybrid state estimator considerably [11].

III. Interdependent Infrastructures Perspective

The IEEE 14 Bus Test System is a reference EPS which is extensively used in the literature for examining concepts in a comparable way. It is a miniature of real systems useful for experimentation, which includes 14 buses, i.e., points of electric power exchange, 5 generators and several loads, i.e., the consumers of power. The particular system was implemented in the PowerWorld simulator using the data given in [12]. The power flow solution obtained by the PowerWorld simulator was used for creating the measurements that are fed to the hybrid state estimator which is implemented in Matlab. It should be noted that the power flow solution from the PowerWorld was transferred to Matlab through an Excel file. For illustration purposes, the 14 bus system is overlaid with eleven Remote Terminal Units (RTUs) to monitor and control equipment on all buses. RTUs are the computerized front-ends of IEDs and PMUs which are connected using communications infrastructure with the primary control center for Supervisory Control and Data Acquisition (SCADA) and Wide Area Monitoring System (WAMS). The SCADA system includes the communications backbone of every modern EPS, while WAMS are extensively deployed during the last few years to enhance the situational awareness of EPS operators with real-time monitoring capabilities.

As seen in Fig. 2, a wide area is considered where the EPS operates and a possible network topology of communication links between RTUs is illustrated. This scenario assumes that the EPS operator owns the communication links at the bottom half of the figure (operator network, red lines), e.g., a private optical fiber network. The six RTUs, as well as the primary and secondary control centers are directly controlled by the EPS operator. For resilience, the EPS operator leases a number of communication links from a carrier (shown with dashed red lines). The remaining five RTUs are assumed to be located in residential and industrial areas, out of the reach of the private optical fiber network of the EPS operator. Therefore, their RTUs are connected with the SCADA system using an ISP's access network via a Virtual Private Network (VPN). The aforementioned communication network was used for illustration purposes and it was assumed that examined RTU communications are over private fiber optics links. Therefore, data congestion is not a critical issue since dedicated fiber links can handle the data traffic created by the RTUs. Modeling the interdependencies among interlinked infrastructures and assessing their impacts on the ability of each system to provide resilient and secure services are of high importance. Specifically for the case of the EPS, following such an interdependency analysis is of utmost importance so as to take steps to mitigate any identified vulnerabilities and protect the system's operation from any internal or external threat. The first step in analyzing interdependencies is identifying them. The case presented below offers an illustration of the type of obvious and not so obvious interdependencies between the EPS and the ICT infrastructure. According to [13] there are four different types of interdependencies of critical infrastructure systems:

- **Physical** interdependency: arises from a physical linkage between the inputs and outputs of two infrastructures.
- **Geographical** interdependency: a local environmental event can create state changes in all involved infrastructures; implies close spatial proximity of the components of different infrastructures.
- **Cyber** interdependency: the state of an infrastructure depends on information transmitted through the ICT infrastructure.
- **Logical** interdependency: the state of each infrastructure depends on the state of the other via a mechanism that is not a physical, cyber, or geographic connection.

Physical and **geographical** interdependencies are relatively straightforward to identify, but require a thorough knowledge of all infrastructures involved. Since information exchange between infrastructure operators is limited, several Physical and Geographical interdependencies go unnoticed until a disruptive event occurs. In the examined WAMS example, the output of PMUs, in the form of synchronized measurements from the EPS, is the physical input to the communication network systems that facilitate data transport to the Control Center. A geographical interdependency may arise if the PMU and the network node are in close proximity, thus affected by the same local events (e.g., thunderstrike or flooding).

In the presented case study, the reliance of the EPS operator to owned and leased communication networks obviously creates a **cyber interdependency**, which needs to be carefully engineered to avoid future contingencies. Although the provisioning of leased communication lines from a carrier network may be tied to strict contractual service level agreements (SLAs) for availability and timely fault repair, these agreements remain private contracts. EPS operators have expressed concerns that these agreements may not be sufficient to guarantee public safety, especially in the event of major catastrophes and natural disasters [14]. The type of **logical** interdependencies are harder to identify and even harder to protect from. They may involve business interests and regulatory conformance of one infrastructure, which may indirectly affect the operation of another infrastructure or even issues of political nature or national security. For example, the reliance of PMUs on the Global Positioning System (GPS) signal for accurate timing synchronization creates a logical interdependency between WAMS and GPS.

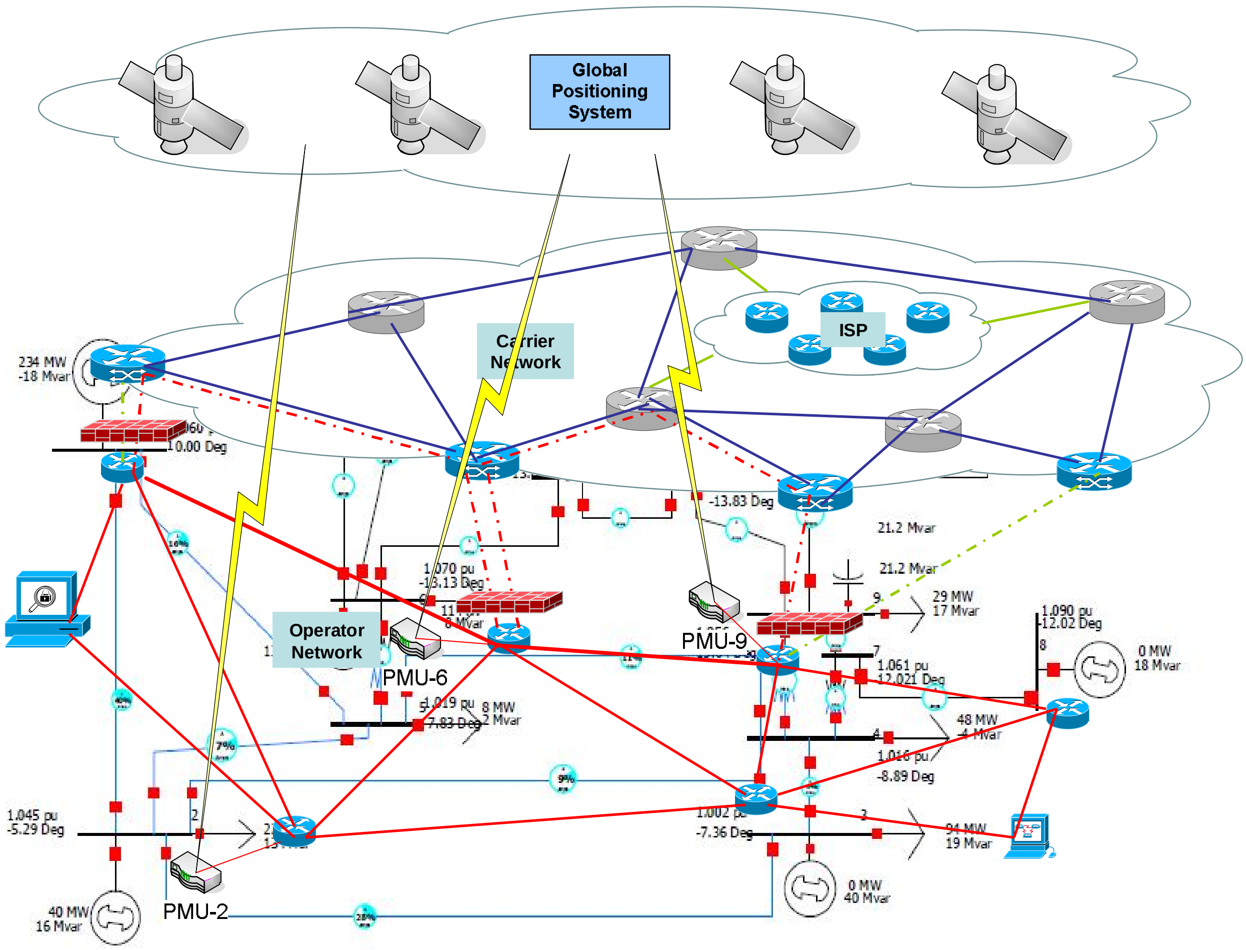

Fig. 2. **Interdependent infrastructures for SCADA and WAMS**

IV. Case Study and Lessons Learned

In this section, a case study for indicating the interdependency between the power and the communication system is shown. The aim of the case study is to investigate the impact of a communication node failure, which transfers PMU measurements to the control center, on the state estimator accuracy. For simulation purposes, the IEEE 14 bus system is used. The system is assumed to be fully observable by both conventional and PMU measurements. Particularly, three PMUs are installed at buses 2, 6 and 9 (Fig. 2). The synchronized phasor measurements are transferred through dedicated fiber optics able to handle the large amount of data provided by PMUs in real time. The PMU measurements are then used along with the conventional measurements to the state estimation tool for estimating the power system states.

The type and the location of measurement units used in this case study are tabulated in Table I. Further, the measurements used in the hybrid state estimator are subjected to Gaussian noise with zero mean value and a standard deviation value according to the type of measurement as shown in Table II. Therefore, the measurements are created by adding the Gaussian noise to the exact measurements of power flow solution provided by the PowerWorld as,

$$P-Q_{flow} = P-Q_{flow\,exact} + unc_{flow}.GN(0,1) \tag{1}$$

$$P-Q_{inj} = P-Q_{inj\,exact} + unc_{inj}.GN(0,1) \tag{2}$$

$$V_{PMU} = V_{PMU\,exact} + unc_{Vpmu}.GN(0,1) \tag{3}$$

$$I_{PMU} = I_{PMU\,exact} + unc_{Ipmu}.GN(0,1) \tag{4}$$

$$\theta_{PMU} = \theta_{PMU\,exact} + unc_{\theta pmu}.GN(0,1)\,, \tag{5}$$

where *unc* is the maximum uncertainty for each measurement type and *GN(0,1)* is the additive Gaussian noise with mean 0 and standard deviation 1. Moreover, it is implicitly assumed that conventional and PMU measurements are synchronized in the execution interval of the state estimation since consecutive state estimation executions have a time difference of 5 minutes.

TABLE I
PLACEMENT OF CONVENTIONAL AND SYNCHRONIZED MEASUREMENTS IN THE IEEE 14-BUS SYSTEM

Flow measurements location (bus # - bus #)	Injection measurements location (bus #)	PMU location (bus #)
1-2, 4-9, 4-7, 7-8, 7-9, 5-6, 6-12, 6-13, 13-14	1, 2, 3, 4, 6, 9, 10, 12, 13 , 11, 14	2, 6, 9

TABLE II
MAXIMUM MEASUREMENT UNCERTAINTIES

Real/reactive power injection (p.u.)	Real/reactive power flow (p.u)	Voltage magnitude PMU (p.u)	Current magnitude PMU (p.u)	Phase angle PMU (degrees)
3/100	3/100	0.02/100	0.03/100	0.01

In order to illustrate the interdependency between EPS and the communication infrastructure, the communication network that transfers the PMU data to the power system control center is supposed to experience a fault during the day. For simulation purposes, during the time interval that the communication link is not available, the respective PMU measurements are simply discarded from the measurement vector used in the hybrid state estimator. As mentioned earlier, the expected performance and reliability of commercial communication networks are documented in SLAs. Typical network availability or VPN availability can range from 99.8% to 99.99%, equivalent to 17.52 hours to 52.56 minutes of downtime per year. However, should a failure occur, the typical Mean Time To Repair (MTTR) is in the range of 5 to 8 hours. Higher availability and lower MTTR are available depending on the network, subject to increased costs. We assume similar metrics for the case of a network owned and managed by the EPS operator, e.g., a 5 hour MTTR.

The loss of the PMU measurements affects directly the accuracy of the state estimator and consequently all the other SCADA applications that rely on state estimator output. It should be noted that any of the three PMUs are not critical measurement units [15] and therefore observability of the power system still holds even with the loss of the measurements from one PMU.

In order to assess the performance of the hybrid state estimator in the case of the communication link failure the variance of the hybrid state estimator is used that is calculated as,

$$\sigma_s{}^2 = \sum_{k=1}^{N} (\mathbf{x}(k) - \hat{\mathbf{x}}(k))^2. \qquad (6)$$

where,
N is the number of the state variables of the EPS
$\mathbf{x}$ is the state vector containing the state variable
$\hat{\mathbf{x}}$ is the estimated state vector.

The variance of the state estimator is shown in Fig. 3 for the three cases of a communication node failure with the RTUs that connect PMUs from buses 2, 6 and 9. The time for establishing PMU communications after the failure is assumed to be 5 hours (MTTR). As it is illustrated in the figure, with the loss of PMU measurements the variance of the state estimator is increased and therefore the accuracy of the state estimator deteriorates. With the restoration of the communication node the estimator variance falls again in the normal level as it was before the failure.

Further, the average variance of the state estimator before and during communication failure, and after communication restoration is tabulated in Table III. It should be noted that the average variance is calculated over the number of state estimation executions in the corresponding time interval. For instance, for the time interval where communication failure occurs and lasts for 5 hours, the average variance is calculated over 60 state estimation executions, since state estimation is performed every five minutes. Comparing the average variance of the state estimator during communication failure for the three cases, it can be concluded that PMUs that are installed on buses 6 and 9 can be considered more crucial in the application of state estimator since the loss of measurements by these PMUs deteriorates more the accuracy of the state estimator in comparison to the case where the communication with PMU 2 is lost. This conclusion can be used as an indication to both power system and communication system engineers. In the case of the power system engineers this information could be an additional knowledge for which of the PMUs are more important to the operation of the monitoring applications of the SCADA system. For the communication engineers this information could provide some directions of how they could reconfigure the communication network for limiting the possibility of losing communication with either PMU at bus 6 or at bus 9 or even worse to lose both PMUs simultaneously. Further, comparing the average variances of the cases before communication node failure and after node restoration it is distinguished a difference in their corresponding values. The difference is statistically not significant and it is due to the random errors introduced to the measurements.

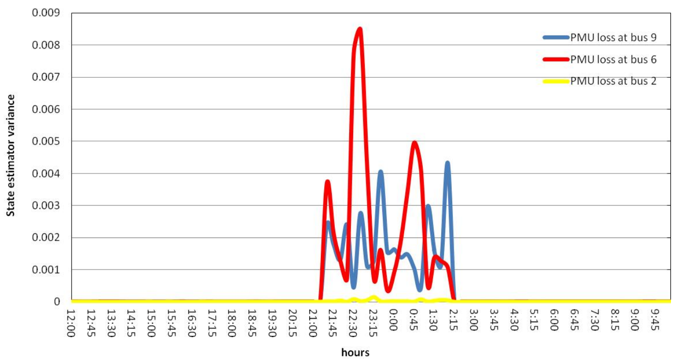

Fig. 3. **PMU communication lost at buses 2, 6 and 9**

TABLE III
AVERAGE STATE ESTIMATOR VARIANCE FOR THE THREE CASES

SUBSTATION WHERE COMMUNICATION IS LOST (BUS #)	AVERAGE VARIANCE BEFORE NODE FAILURE	AVERAGE VARIANCE DURING NODE FAILURE	AVERAGE VARIANCE AFTER NODE RESTORATION
2	4.72×10^{-7}	3.58×10^{-5}	7.46×10^{-7}
6	4.83×10^{-7}	2.66×10^{-3}	6.97×10^{-7}
9	4.55×10^{-7}	1.85×10^{-3}	7.38×10^{-7}

V. CONCLUSION

In spite of the simplicity of the case study, it reveals some important aspects of complexity in the coexistence of power and communication systems. The two systems are interdependent, since a disoperation of the communication network affects the power system operation. The concept of complexity comes forth in the case where the design of a certain part of the communication network should meet the communication requirements of the power system operation. In this case, many parameters should be taken into consideration for both entities before proceeding to the design. From the EPS perspective, the time scale for each monitoring and control application and the measurement criticality for each measurement should be determined. This information should be evident to the ICT engineers for deciding the medium and the architecture of the communication network. From the communication system perspective, the communication capabilities of each power system area should be assessed accordingly. This assessment will give an indication to the power system engineers for the possible location of advanced measurement units (i.e., PMUs) that report respectively large amount of data in real time and require substations with high communication capabilities. The aforementioned actions undertaken by both communication and power system operators become even more complex when the factor of cost is considered. A cost effective solution for the first entity is not always cost effective to the other, and thus, a multi-objective optimization problem needs to be set up, considering both operational and economic objectives and constraints.

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