Information Exchange Needs for New Fault Location Applications in T&D Systems

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***Abstract*—This paper investigates new applications that reduce the impact of outages in power systems, which are made possible with expanded data acquisition and communication solutions introduced through the development of smart grid. Requirements for such applications are highlighted by studying their use cases. Standards associated with data formats and communication protocols facilitating data integration are also identified.**

I. INTRODUCTION

Detection and accuracy of fault determination have a direct influence on the duration and scale of associated outages. Applications have been developed to reduce the impact of faults at different voltage levels in power systems. At the transmission level, fault location algorithms have been incorporated in Digital Protective Relays (DPRs) so that the crews are informed of the type and location of faults by reading relay's reports before going for a field inspection; Digital Fault Recorders (DFRs) installed in critical substations are triggered to capture transient waveforms during faults, which also may serve as inputs in the fault location determination process [1]. At the distribution level where recording devices are not so common, Outage Management Systems (OMS) analyze information from trouble calls and metering system to narrow down the fault area and predict the cause of faults [2].

New fault location applications can be implemented by utilizing the emerging data acquisition and communication technologies deployed as a part of the Smart Grid development. At the transmission level Wide Area Monitoring, Protection and Control (WAMPAC) System guarantees fast response to faults. It uses phasor measurements provided by substation Intelligent Electronic Devices (IEDs) for detecting power system faults and disturbances [3]; At the distribution level advanced fault location techniques may achieve better accuracy and hence shorten the time for fault locating process by taking advantage of data from smart meters, power quality meters, protective relays and any sensors deployed in the smart distribution system [4].

The progress mentioned above requires extensive information exchange from IEDs across the system using upgraded communications. The development of smart grid provides, besides additional sensors, new communication facilities for transmitting data with higher quality and speed, and new software for exchange of information between multiple locations of measurements and multiple users and applications.

This paper focuses on fault location improvements by discussing related application in the transmission and distribution systems. The following problems are discussed in the subsequent sections : Examples of new applications for fault location in transmission and distribution; the data format and communication requirements to implement these applications; standardization needs.

II. BACKGROUND

A. Smart Grid Application Domains

The Smart Grid Interoperability Panel (SGIP) was established by the National Institute of Standards and Technology (NIST) to coordinate development of interoperability standards [4]. The Smart Grid Architecture Committee (SGAC) of SGIP has formed a conceptual model and divided the Smart Grid into seven domains in order to better illustrate planning and organization of the diverse and expanding collection of interconnected networks that constitute smart grid. Each of the seven smart grid domains is a high-level grouping of organizations, facilities, individuals, systems, devices or other actors that have similar objectives and that rely on—or participate in—similar types of applications [4].

To study the smart grid process definition and requirements, the Electric Power Research Institute (EPRI) has created a repository to document use cases for existing applications in the seven domains [5]. The emerging applications, on the other hand, are often ignored. Requirements from the new applications may differ from the existing ones in several ways: accuracy, latency of data transfer, bandwidth, etc. Communication infrastructures designed for the existing applications may fit the new applications, but most often a retrofit or new design is needed.

B. *Transmission-Level Fault Location*

Transmission line faults may be calculated using fundamental frequency components of voltage and current or higher frequency transients generated by the fault. Both of these methods can be subdivided into another two broad classes within each category depending upon the availability of recorded data: single-end methods, where data from only one terminal of the transmission line is available and double-end methods, where data from both (or multiple) ends of the transmission line can be used. Double-ended methods can use synchronized or unsynchronized phasor measurements, as well as synchronized or unsynchronized samples [7].

Each of the techniques requires very specific measurements from one or both (multiple) ends of the line to produce results with desired accuracy. However, availability of data may be a challenging issue. Digital fault recorders (DFRs) and other IEDs are generally placed only in most critical substations and therefore in some cases it is not possible to get recorded measurements from both or any end of the faulted line if DFR is used as a source of data. Therefore, neither double nor single-end methods can always be applied. In such cases some unconventional techniques based on wide area measurements may have to be used [7].

C. *Distribution-Level Fault Location*

Methods proposed for fault location on transmission lines are not easily applicable to distribution systems. A suitable fault location method has to consider the limitation of the host processing platforms and requirements of the algorithm itself. Heterogeneity of the lines, presence of laterals, load taps, and comparatively a lower degree of instrumentation in distribution systems are among the limitations. Based on the type of data that the fault location techniques use to find the location of the fault they may be categorized as follows [8]:

- Apparent impedance measurement
- Direct three-phase circuit analysis
- Superimposed components
- Traveling waves
- Power quality monitoring data

As a part of smart grid deployment projects, IEDs for monitoring, protection, and other purposes including the smart metering systems, power quality monitors, and distribution automation system have emerged in distribution applications. These smart sensors are installed all over the system, going from substation down the feeders to the customer location. Their types vary, as well. Development in smart grid communications makes the data captured by these new devices available to multi subscribers and serves for multiple IED infrastructures. Hence, utilization of the gathered data from various IEDs installed along the feeders is quite feasible. Availability of additional feeder data may help improve the accuracy of the fault location methods. However, there are standing concerns that should be taken into account: how different types of IEDs available in the network may affect the fault location method selection, what are the factors that influence quality of recorded data, and how the feeder automation architectures impact the final availability of data.

III. USE CASES FOR SELECTED APPLICATIONS

A. *Transmission Fault Location*

An optimal fault location approach will select the most appropriate fault location algorithm depending on the availability and location of the data measured. The Optimized Fault Location Algorithm (OFLA) [9] selects the best result using the process described in the flowchart shown in Fig. 1.

The measurement equipment used to capture data are sparsely located Digital Fault Recorders (DFRs), Digital Protective Relays (DPRs) or other GPS-connected IEDs, e.g. Phasor Measurement Units (PMUs) or DPRs. Commercial software like PSS/E or PowerWorld is utilized to run power flow analysis and display the fault location results.

B. *Distribution Fault Location*

The voltage sag based method proposed in [8] is based on the fact that when a fault occurs on the feeder, voltage sags propagate presenting different characteristics for each feeder node. This requires voltage sag data gathered from revenue meters with transient recording capabilities or power quality meters installed at strategic points along the feeder. The method does not suffer from multiple outputs like many other methods. Flow chart for this method is shown in Fig. 2.

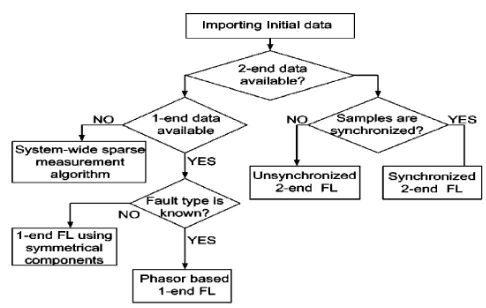

Figure 1. Flowchart of Optimized Fault Location Algorithm [9].

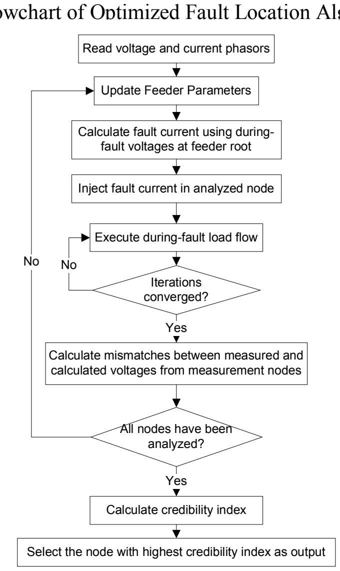

Figure 2. Flow chart for voltage sag based fault location method.

C. *Data Flow*

All involved actors and exchanges of data between actors in the transmission and distribution fault location are recorded in Table I. “R” in the last column represents “real-time”, “O” represents “offline” and “S” represents “synchronization”. The communication paths are shown in Fig. 3.

IV. REQUIREMENTS FOR THE SELECTED APPLICATIONS

A. *Data Integration*

The main idea of data integration is collecting data from the new sources, and sharing it between multiple applications. One example is sharing data recorded by various Intelligent Electronic Devices (IEDs).

At the transmission level, a smart integrated substation is normally equipped with various types of IEDs which can be used for monitoring, control, and protection purposes. The databases, which may be located partially in substations, at the SCADA systems or elsewhere in the utility enterprise consists of the following data:

TABLE I. FLOW OF DATA

NO	Data	From	To	Requirements
1	Event Data	Substation Database	FL	R
2	PI Historian	SCADA Database	FL	O
3	System Model	EMS	FL	R
4	FL Report	FL	Visualization Unit in EMS	O
5	Raw Data (samples)	Substation	SCADA	R
6	Over Current Alarm	DPRs	Substation Database	R
7	Relay Operation Report	DPRs	Substation Database	R
8	Power Flow	IEDs	Substation Database	R
9	Event files	DFRs	Substation Database	R
10	Synchronized Samples	PMUs	Substation Database	S
11	Distribution Event Data	Distribution IEDs	Distribution FL	R
12	System Model	DMS	Distribution FL	R
13	Power Flow	Distribution IEDs	Distribution FL	R

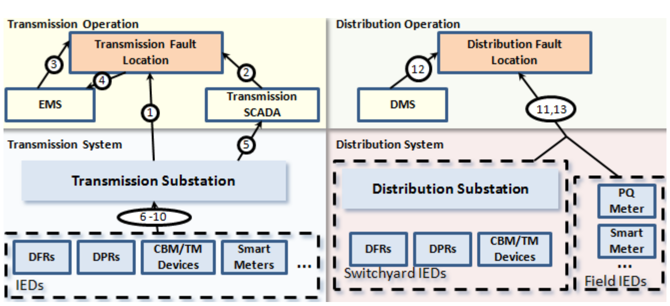

Figure 3. Communication paths

- Measurements received from RTUs;
- Measurements received from other IEDs;
- Static system model data containing description of system components and their connections (i.e., topology);
- SCADA EMS PI Historian data, which may be used to tune the static system model with real-time data;
- Interpretation data that allows one to correlate the naming convention of recording devices to that of the static system model used to describe PI Historian data.

At the distribution level, as a part of smart grid deployment projects, IEDs for monitoring, protection, and other purposes including the smart metering systems, power quality monitoring, and distribution system automation have emerged in large numbers.. Development in smart grid communications makes the data captured by these new devices available to multi subscribers and serves multiple IED infrastructures. Hence, utilization of the gathered data from various IEDs installed along the feeders is quite feasible.

B. *Data Transmission*

Integrating a huge amount of data provides improved information by exploiting the redundancy, but also creates challenges to communication networks:

- 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 FL data 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.

C. *Retrofit of Feeder Automation Architecture*

This is mainly a distribution-domain issue due to the radial configuration of feeders. Different types of communication have been used based for feeder automation (FA). Centralized Feeder Automation acquires data from field devices, process data in a SCADA system of DMS and issue supervisory control commands. Distributed data acquisition approach is controlled by substation PLC or RTU. Data are acquired from field devices and processed in a substation and supervisory control commands are issued to field devices, as needed. Peer-to-Peer Arrangement acquires "local" data via local sensors and "remote" data via peer-to-peer communications with other controllers, and process data locally so that no DMS SCADA-based central location is required. The method reported in [8] provides more accurate results which pinpoints fault to the nearest node (usually in a range of several hundred meters), but requires a centralized FA structure, which is not widely available.

V. STANDARDIZATION ISSUE

Standardization is another important issue in implementing new applications. There are three layers in the standards coordination process: a) identification of related standards; b) mapping of existing standards to realize interoperability; and c) development of new standards to fill the gaps between existing standards. One example is the 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 data [10]. 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 FL. CBM, DFR and some other IEDs that may introduce new functionality 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 their monitoring and control aspects [11]. 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 [12].

Fig. 3 shows all the related standards for the sample applications of transmission and distribution fault location. The standards cover data exchange including communication protocol and interfaces.

VI. CONCLUSION

This paper discusses new information exchange needs and communication system requirements for outage management in transmission and distribution applications. The following issues are addressed:

- New applications. Example applications that can reduce the impact of outage are selected. Such applications include transmission and distribution fault location.

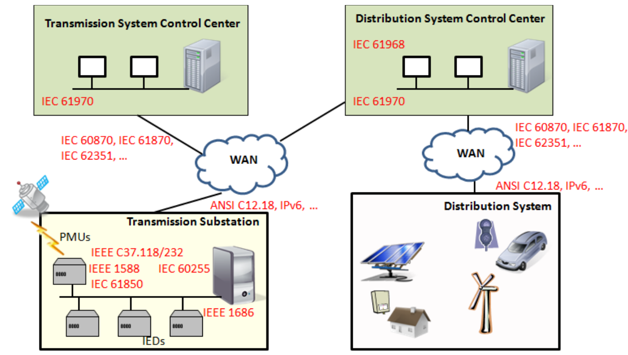

Figure 4. Standard related to transmission and distribution fault location applications.

- New requirements from emerging applications. The communication systems under the development of smart grid will have to be retrofitted or redesigned to meet such requirements.
- Related standards. As a contribution to the standardization study, existing standards are surveyed, classified, and highlighted according to its importance to our study.

VII. REFERENCES

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