Use of Substation IED Data for Improved Alarm Processing and Fault Location

Papiya Dutta, Yufan Guan *Student Member*, *IEEE* and M. Kezunovic, *Fellow*, *IEEE* [1]

***Abstract*-- With the advent of technology, substations of modern days are being equipped with different types of IEDs (Intelligent Electronic Devices) such as Digital Protective Relay (DPR), Digital Fault Recorders (DFR), Phasor Measurement Units (PMU), etc. These devices are capable of recording huge amount of data and thus integration and appropriate use of those data can be beneficial to the power industry. There are several issues to be solved in this regard: (1) Which data to be used and when (for what application), (2) Accuracy of such data (in the measurement process from the place of data capture to where it is used), (3) Extraction of useful information from captured data and (4) Use of the information in applications. This paper focuses on these issues and also some new applications which can use those substation IED data.**

***Index Terms*-- IED data, substation automation, alarm processing, fault location.**

I. Introduction

TRADITIONALLY in a substation, supervisory control and data acquisition system (SCADA) data are typically bus voltages, flows (amps, MW, MVAR), frequency, breaker status, transformer tap position) acquired using remote terminal units (RTUs) and sent to the energy management systems (EMS) in every two to ten seconds. With the rapid advancement of technology, intelligent electronic devices (IED) come into picture. These modern day digital devices can record and store a huge amount of data with a periodicity depending upon the intended purpose of the device (DFRs only capture data during occurrence of a fault whereas PMUs take continuous time-synchronized data with high sampling rates). Thus we are having a great amount of data, which if used properly can become a great benefit for the EMS to predict, operate, monitor and post-mortem analyze power system events.

Although the IEDs are digital devices (having very small % data processing error), accuracy of data is still a major concern, as there are several sources of error in the whole measurement chain (starting from the point where data is fetched to the digital word produced). Some amount of distortion either in magnitude or in phase or both are introduced in each stage of the measurement chain (termed as instrumentation channel [1]) and the signal no longer remains the ideal replica of the actual signal. The typical issues related to accuracy in the instrumentation channel are shown in Table I.

TABLE I. Issues related to accuracy

Instrument Transformers and Control Cables
▪ Classes and accuracies of CTs and PTs
▪ Performance of instrument transformers under various dynamic conditions
▪ Other errors (e.g. saturation of core, aging) associated with instrument transformers
▪ Effect of length and type of control cables
Intelligent Electronic Devices (IED)
▪ Signal processing accuracy
▪ IED data accuracy under following operating conditions
• Normal (revenue metering and operator metering)
• Disturbances (power quality such as sags, swells, impulses, harmonics)
• Faults (protective relaying)
• Low frequency oscillations (generator interactions)

The discussion of the paper is divided broadly into two parts. The first part concerns solely about the characteristics of data (accuracy and synchronization of data) and extraction of useful information from huge amount of redundant data. The second part shows how the IED data integrated with SCADA data can be applied in power system operations. This is supported by two implementation examples: one being alarm processing and the other optimized fault location.

II. Data

Here we will discuss the characteristics of the data recorded by different types of substation IED.

Typically in a modern day integrated substation, various types of IEDs are employed for monitoring and control purposes. Once the substation data at high power level are collected they must be transformed to instrumentation level using current and voltage instrument transformers. The data are then filtered and digitized, and submitted for the processing in IEDs. Finally, the intended information is extracted and supplied as output of these devices. This is the typical measurement data processing chain for the data.

A. Data Sources

The different measurement devices (collectively termed as sensors) that are source of data fall into the following categories:

- Transducer
- Relaying transformers

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Papiya Dutta, Yufan Guan and M. Kezunovic are with Department of Electrical and Computer Engineering, Texas A & M University, College Station, TX 77843, USA (e-mails: papiya82@tamu.edu, carling@tamu.edu, kezunov@ece.tamu.edu).

- Metering transformers
- Electronic (optical) transformers

Traditionally, the data processing is done by substation RTUs. Nowadays the different IEDs used to process data in a typical substation are [2]:

- Digital protective relay (DPR)
- Digital fault recorder (DFR)
- Phasor measurement units (PMUs)
- Power quality meter (PQM)
- Sequence of event recorder (SER)
- Fault locator (FL)
- Circuit breaker monitor (CBM)
- Programmable logic controller (PLC)
- Remote terminal unit (RTU)

These IEDs are intended for specific function (sometimes for multiple functions) and depending upon power system events IEDs record analog and/or status data either in a specific location or for the entire substation.

Distortion in magnitude and phase angle of current and voltage signal is introduced in each stage of the measurement chain. Ideally the output waveform should be an exact replica of the input signal, but the error introduced in several stages make the output distorted. This section is aimed at discussing the desired performance characteristics of the different stages in the measurement chain.

B. Sensors

Sensors (instrument transformers and transducers) measure current and voltage (for either metering or protection purposes) from high voltage electric circuit (primary side) and supply the RTUs or other IEDs (secondary side) these quantities proportional to those of the power circuit but in substantially reduced level and thereby provide galvanic isolation and signal scaling of signals for these devices from high voltage circuitry. Generally, conventional instrument transformers (current transformers CT, voltage transformers VT and capacitive coupled voltage transformers CCVT) are relatively inaccurate comparing to the microprocessor based IEDs. The accuracy of data is highly dependent on the accuracy of instrument transformers, control cables and burdens (the external load connected to secondary transformer terminals, including IEDs for this discussion).

Next we focus on determining inaccuracies of instrument transformers under various conditions (steady state, transients, switching etc).

IEEE Standard C57.13 on requirements for instrument transformers [3] and IEC standard 60044 [4] define instrument transformer types, parameters for insulation class and accuracy class, standard burden types. With this knowledge it is possible to predict the inaccuracies in instrument transformers as well as understand how they reflect on the performance of IEDs.

The instrument transformers are designed to operate for either metering purposes (upto full load of the system) or protection purposes (for faulted system). Accordingly the preferred accuracy is also different.

For metering, the transformer correction factor (TCF, combined ratio and phase angle error) for the accuracy classes as defined in IEEE Standard C57.13 and C57.13.6 ([5]for high accuracy transformers) is shown in Table II (for 0.6-1.0 lagging power factor of metered load). For current transformers, the error limits are mentioned not for the entire range of the rated current. When the current becomes very low (much less than 5% of rated current), the errors become exponential due to non-linearity. As the current (and flux density) increases above the rated current, the errors remain linear until the characteristic enters into saturation zone, and after that there will be huge increase of ratio error and distortion in secondary current waveform. For voltage transformers, the accuracy class is defined within 90% to 110% of rated voltage. Saturation of VT occurs at not much above 110% of rated voltage as the operating flux densities are much higher than that of CTs. The standard burdens are 0.1, 0.2, 0.5, 0.9, 1.8 ohms which corresponds to 2.5,5, 12.5, 22.5, 45 VA respectively (for CT accuracy classes 0.3-2.4).The burdens used for metering purposes with CT accuracy classes 0.15 and 0.15S are 0.2 and 0.04 ohms which correspond to 5 and 1 VA respectively. All the burdens are defined for 5A secondary current.

TABLE II. TRANSFORMER CORRECTION FACTOR FOR METERING ACCURACY CLASSES

Accuracy Class	Transformer Correction Factor Range			
	CT			VT
	% rated current			
	100	10	5	
0.15S	0.9985-1.0015		0.9985-1.0015	N.A.
0.15	0.9985-1.0015		0.997-1.003	0.9985-1.0015
0.3	0.997-1.003	0.994-1.006		0.997-1.003
0.6	0.994-1.006	0.988-1.012		0.994-1.006
1.2	0.988-1.012	0.976-1.024		0.988-1.012
2.4	0.976-1.024	0.952-1.048		0.976-1.024

As per IEC standard for CTs (IEC-60044-1) the ratio error (current) for the accuracy classes for metering CT defined in that standard are shown in Table III (for 0.8 lagging power factor of metered load). The burden should be 25%-100% of rated burden for accuracy classes 0.1-1.0 (including 0.2S and 0.5S) and 50%-100% of rated burden for accuracy classes 3.0-5.0. The standard burdens are 2.5,5, 10, 15, 30, 40 VA respectively.

TABLE III. RATIO ERROR FOR METERING CT ACCURACY CLASSES

Accuracy Class	Ratio Error (± %)					
	% rated current					
	120	100	50	20	5	1
0.1	0.1	0.1		0.2	0.4	
0.2S	0.2	0.2		0.2	0.35	0.75
0.2	0.2	0.2		0.35	0.75	
0.5S	0.5	0.5		0.5	0.75	1.5
0.5	0.5	0.5		0.75	1.5	
1.0	1.0	1.0		1.5	3.0	
3.0	3.0		3.0			
5.0	5.0		5.0			

As per IEC standard for inductive VTs (IEC-60044-2) the ratio error (±% voltage) for the accuracy classes for metering inductive VT defined in that standard are 0.1, 0.2, 0.3, 0.5, 1.0, 3.0 (for 0.8 lagging power factor of metered load and within 80% to 120% of rated voltage). The burden should be 25%-100% of rated burden. The standard burdens are 10, 15, 25, 30, 50, 75, 100, 150, 200, 300, 400, 500 VA respectively. For capacitive VTs (IEC- 60044-5), the accuracy classes are same as accuracy classes 0.2-3.0 of inductive VTs.

As per IEEE standard, for relaying purposes, TCF should not exceed 10% at 1-20 times rated secondary current at the standard burden or any lower burden.

Relaying CT is classified into two classes:

Class C: Low leakage reactance type i.e. the leakage flux does not have considerable effect on the ratios.

Class T: High leakage reactance type i.e. the leakage flux has considerable effect on the ratios.

Secondary terminal voltage rating of relaying CT is the voltage the transformer will deliver across a standard burden at 20 times rated secondary current without exceeding 10% ratio error. The available burdens are 0.1, 0.2,1,2,4, 8 ohms which correspond to secondary terminal voltage of 10, 20, 50,100,200,400V respectively. The standard burdens are W, X, M, Y, Z, ZZ which corresponds to VA of 12.5,25,35,75,200,400 respectively.

As per IEC standard for current transformers (IEC-60044-1) there are two accuracy classes for relaying CT (5P and 10P: P stands for protection).The standard burdens are 2.5,5,75,10, 15 and 30VA.

Though IEEE standard does not define accuracy classes for relaying VT, there are two accuracy classes for relaying inductive VT in IEC standard 60044-2. The ratio error (±% voltage) for the accuracy classes (3P and 6P) defined in that standard are 3.0 and 0.6 (for 0.8 lagging power factor of metered load). The accuracy class is defined within 5% of rated voltage to rated voltage multiplied by RVF, where rated voltage factor (RVF) is the multiplying factor to be applied to the primary accuracy rating voltage to determine the maximum voltage at which a transformer complies with the relevant thermal requirements for a specified time, and at which a relaying inductive VT complies with the relevant protective accuracy classes. The burden should be 25%-100% of rated burden.

For relaying capacitive VTs (IEC- 60044-5), the ratio error (voltage) for the accuracy classes (3P and 6P) defined are 6.0 and 12.0 for 2 % rated voltage and 3.0 and 6.0 for 5 % rated voltage and rated voltage multiplied by the RVF (1,2, 1,5 or 1,9).

The DC component of the fault current may force the CTs to enter into saturation by significantly increasing the flux. However, this increase in flux depends on time constant of the circuit and thus most of the high speed relay operates before CT enters into saturation zone.

Magneto-Optic current transformers (MOCT) and Electro-Optic Voltage Transducer (EOVT) that operate on optic principles (Faraday's effect and Pockel's effect respectively) are much more accurate than traditional electromagnetic instrument transformers as they can operate under linear operating region over wide dynamic range. These transformers are typically designed to meet IEC 0.2S accuracy class or IEEE 0.15S accuracy class.

Current and voltage transducers have low voltage outputs to be directly used with microprocessor based metering and relaying devices. These devices are much more accurate as there is no problem associated with saturation of core and can be simultaneously used for both metering and relaying purposes.

C. *Intelligent Electronic Devices*

Usually the microprocessor based IEDs have very good accuracy. While the basic data processing stages for IEDs are similar (as shown in Fig.1), the recording performance may differ. In all of the IEDs, the basic data processing steps are:

- Galvanic isolation using auxiliary transformer
- Low pass (anti-aliasing) filtering of the analog input waveforms to eliminate the high frequency components
- Sampling of the analog input waveforms
- Analog to Digital (A/D) conversion
- Processing of the digital signal samples

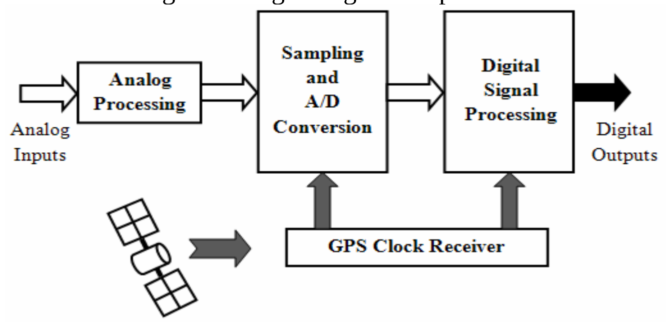

Fig. 1. Data Processing in IED

The overall accuracy of the IED analog signal input channel depends on several factors [6]:

- Impact of auxiliary transformers
- Mode of sampling
- Anti-aliasing filtering
- Sampling rate
- Resolution of A/D conversion

Some of the IEDs (DPR, DFR, FL etc) operate on synchronous sampling and some (RTU) operate on scanning of samples. As shown in Fig.2, when scanning, one analog input channel is sampled at a time and then converted to digital signal, whereas in synchronous sampling all the input channels are sampled at the same time and then they are converted to digital signal (there may be only one ADC serving all channels or each of the analog input channels has combined sample-and-hold circuit and ADC). Retrieving the actual phase difference between analog signals is easy in synchronous sampling as all signals are sampled at the same time. In case of synchronized sampling, the clock signal may be provided locally or from a receiver for the Global Positioning System (GPS) of satellites [7]. Most of the IEDs of modern day are using GPS for sampling and time stamping.

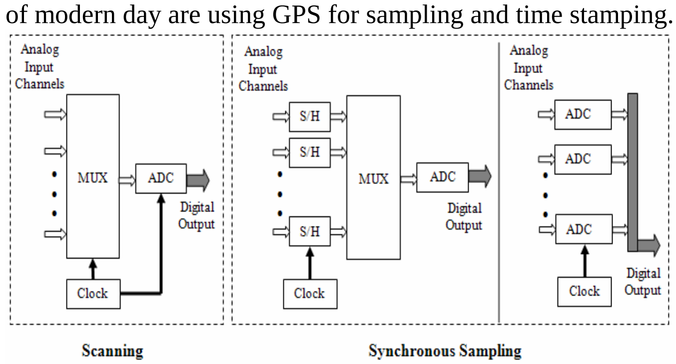

Fig. 2. Scanning and synchronous sampling of analog inputs

The replication of signal largely depends on the "horizontal" resolution (sampling rate) and "vertical" resolution (number of bits for ADC). With higher sampling rate, the better signal representation is achieved. With more bits, better signal accuracy is achieved). Sampling rate also affects the choice of anti-aliasing filters. DPR generally is a device with low sampling rate (16 samples/cycle i.e. 960Hz for 60Hz system). Some of the DFRs of modern day achieved much higher sampling rates of 48 kHz. Again the higher value of vertical ADC resolution is desirable. Most of the IEDs use 16 bit ADC resolution. The selection of the resolution is driven by the ADC cost and dynamic behavior of the measured signal.

While most of the other IEDs allow access to samples of signal, phasor measurement unit (PMU) provides measurements of synchronous phasors of analog inputs. The GPS synchronized PMUs are the most accurate among all IEDs. Such GPS synchronized devices provide phasor data termed as synchrophasor. The IEEE C37.118 [8] (extension of IEEE Standard 1344) is used for accuracy definition of synchrophasors:

- Magnitude accuracy of 0.1% or better
- Time accuracy better than 1 μs or phase angle accuracy of 0.02° at 60 Hz.

The North American Synchro Phasor Initiative (NASPI) is looking at dynamic accuracy beyond what is defined in C37.118 [9].

The total vector error for synchrophasors defined in this standard should be less than 1%. [8]

Where, $\text{Total Vector Error (TVE)} = \dfrac{|X_n - X|}{|X|}$

X = theoretical value and X_n = measured value

III. IED Data Formats and Data Uses

A. Data Formats

Getting required information from huge amount of redundant data obtained from different IEDs (having different data format) is an issue that requires particular attention. Whenever the data from different IEDs is retrieved in a database, the data integration requires [10-11]:

- Interpreting the data obtained from IEDs of different vendors
- Exchanging data using standard COMTRADE file format [12]
- Adding the static system configuration data according to the recorded data

To integrate data among different IEDs and IEDs from different vendors, standardized data format is necessary. After the introduction of COMTRADE data format [12], most of the vendors are accepting this standardized data format, while some are still others are keeping their own native data formats [10]. The power quality meter data representation is standardized using Power Quality Data Interchange Format (PQDIF) [13]. Most recently, another useful standard has been adopted for representation of time-sequence data [14].

B. Data Uses

The use of data available from IEDs as well as the other data (SCADA data collected using RTUs, satellite data, and static system data) enhances some power system functions.

The basic idea is to collect all the data in a substation database and use further for extracting information automatically. This extracted information then may be used for several power system applications [15-16]. To import the IED data into the central repository requires means of data format conversion and communication among different IEDs. In addition to the automatically retrieved RTU and other IED data, the database should contain several other data, such as:

- Static system data containing description of the system components and their connections (i.e. topology)
- Substation interpretation data to correlate the naming convention between the recording devices and static system model
- SCADA EMS PI Historian data to tune the static system model with real time data.

By integrating data from all the sources, quality of data is improved due to the redundancy of the great amount of data collected. The next two sections give examples of how the integration of data can benefit new applications.

IV. Intelligent Alarm Processing (IAP)

With the growth of power system complexity, operators are often overloaded with alarm messages generated by the events in the system. A major power system disturbance could trigger hundreds and sometimes thousands of individual alarms and events [17]. Obviously, this is beyond the capacity of any operators to handle. Thus, operators may not able to respond to the unfolding events in a timely manner, and even worse, the event interpretation by the operators may be either wrong or inconclusive affecting their ability to perform expected actions. The task of an intelligent alarm processor is to analyze thousands of alarm messages and extract the information that concisely explains the network events.

A. Intelligent Alarm Processing Algorithm

A lot of research has been done on the Fuzzy Reasoning Petri-nets (FRPN) [18-20]. FRPN takes advantages of Expert System and Fuzzy Logic, as well as parallel information processing to solve the problem of fault section estimation. Reference [21] gives an optimal design of a structure of FRPN diagnosis model.

It has been proven that the logic operand data of digital protective relays can be used as additional inputs to enhance the alarm interpretation [15]. In a digital protective relay, the pickup and operation information of protection elements is usually in the form of logic operands [22]. The pickup and operation logic operands are more reliable than SCADA data because they are more redundant and have less uncertainty than relay trip signals and circuit breaker status signals.

In such a solution, input data such as relay trip signals and circuit breaker status signals are acquired by RTUs of the SCADA system. Relay logic operand signals are defined in their data memories and retrieved from relays by the SCADA front-end computers in substations. The data are acquired from different substations and are transmitted to the control center through selected communication link such as microwave or optical fiber. In the control center, the SCADA master computer puts the input data into a real-time data base and keeps updating them at each scan time.

B. Data Requirements

The detailed description of field data needed for this application is listed in Table IV.

TABLE IV. DATA LIST FOR OPTION A

Data from RTU of SCADA (Main data)	
1	CB status change alarms (Opening and Closing)
2	Trip signal of Main Transmission Line Relays
3	Trip signal of Primary Backup Transmission Line Relays
4	Trip signal of Secondary Backup Transmission Line Relays
5	Trip signal of Bus Relays
Data from Digital Protective Relays (*Additional data)	
1	Pickup & Operation signals of Main Transmission Line Relays
2	Pickup & Operation signals of Primary Backup Transmission Line Relays
3	Pickup & Operation signals of Secondary Backup Transmission Line Relays
4	Pickup & Operation signals of Bus Relays

C. Implementation

A 14-bus power system is used for the study of fault section estimation problem. The system consists of 34 sections, including 14 buses and 20 transmission lines. The buses are denoted as Bnn. The transmission lines are denoted as Lnnmm.

We used backward reasoning concept to structure the FRPN diagnosis models and generalize the design for transmission lines and buses [23]. Fig. 4 and Fig. 5 illustrate backward reasoning concept for structuring transmission line and bus diagnosis models respectively. The 'AND-OR' structure concisely represents all the possible combinations of main, primary backup and secondary backup protection operations for inferring a fault. Compared with the 'OR-AND' "enumeration" type of structure used in [21], our proposed structure effectively covers more scenarios with smaller number of rules, which will eventually achieve higher diagnosis accuracy with smaller size of Petri-nets matrix.

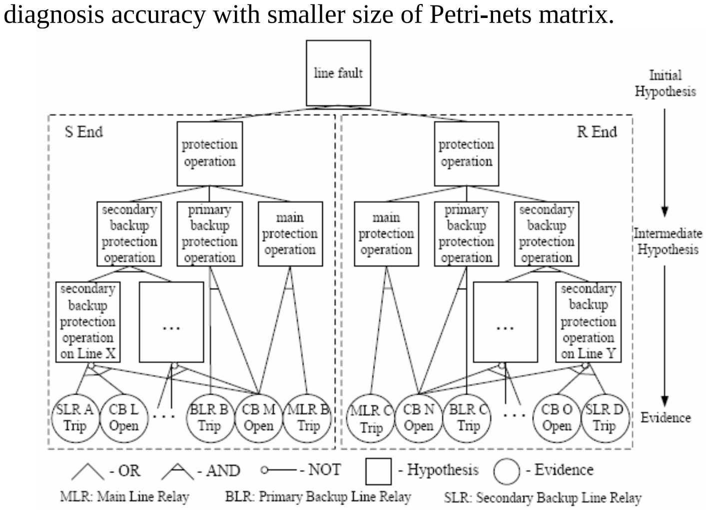

Fig. 4. Backward Reasoning concept for structuring transmission line diagnosis models

Based on the proposed structure, all the FRPN diagnosis models are developed. Fig.6 shows the FRPN models for the transmission line L1314.

The pickup and operation logic operands can be utilized to improve the accuracy of fault section estimation based on SCADA data. When a fault occurs on the transmission line L1314, its associated protection system operated to respond to the fault. In addition to the observed SCADA data, the following relay signals are also observed: SLR0613 Pickup, SLR0613 Operation, SLR1213 Pickup, SLR1213 Operation, BLR1314 Pickup, BLR1314 Operation, MLR1314 Pickup, MLR1314 Operation, MLR1413 Pickup, MLR1413 Operation, BLR1413 Pickup, and SLR0914 Pickup. Since the relay data are more reliable than the SCADA data, they are given a larger truth value 0.98.

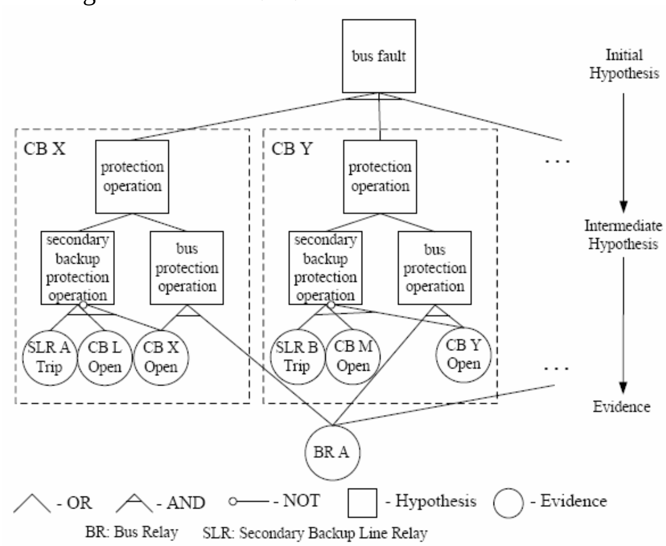

Fig. 5. A FRPN model for L1314 fault based on SCADA and digital protective relay data

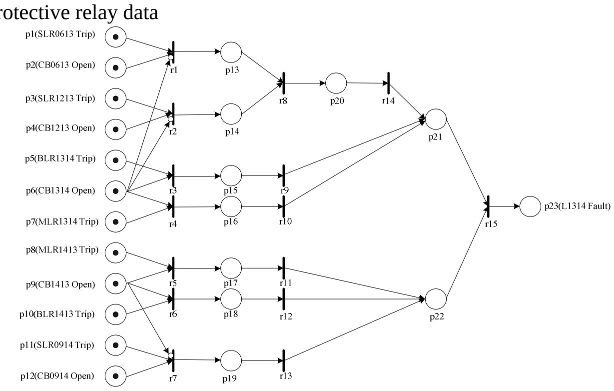

Fig. 6. A FRPN model for L1314 fault based on SCADA data

Fig.7 illustrates how the pickup and operation information is added into the FRPN model built for diagnosing a fault on the transmission line L1314.

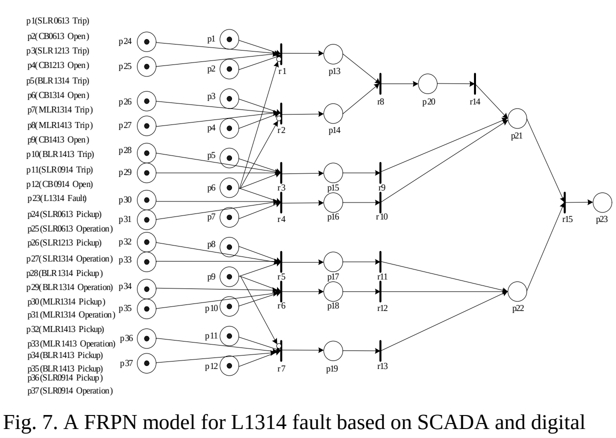

Fig. 7. A FRPN model for L1314 fault based on SCADA and digital

If MLR1413 Trip is missing in the SCADA data due to data transmission error while MLR1413 Pickup and

MLR1413 Operation are observed, the conclusion will be that a fault occurs on the transmission line L1314 with a truth degree value 0.827.

D. Case Study

Based on the approach introduced in [15], a power system/protection system interactive simulation environment for the case study has been developed. The evaluation environment enables one to set up fault scenarios, insert user-defined errors, and generate SCADA data and relay data.

A permanent fault occurred on the bus B04 at 0.05 second. A second permanent fault occurred on the bus B09 at 0.09 second. All the protection devices operated correctly. No false data occur. The observed SCADA data are listed in Table V. The observed relay data are listed in Table VI.

TABLE V. SCADA DATA

Sequence No.	Time Stamp (Sec)	Observed Signal
1	0.1000	BR04 TRIP
2	0.2000	CB0402 OPEN
3	0.2000	CB0403 OPEN
4	0.2000	CB0405 OPEN
5	0.2000	CB0407 OPEN
6	0.2000	CB0409 OPEN
7	0.2000	BR09 TRIP
8	0.2000	CB0904 OPEN
9	0.2000	CB0907 OPEN
10	0.2000	CB0910 OPEN
11	0.2000	CB0914 OPEN

TABLE VI. RELAY DATA

Sequence No.	Time Stamp (Sec)	Observed Signal
1	0.0662	SLR0409
2	0.0677	SLR0709
3	0.0693	BLR0910
4	0.0698	MLR0910
5	0.0703	MLR1009
6	0.0703	BLR1009
7	0.0703	SLR1110
8	0.0724	SLR1409
9	0.0740	MLR0910
10	0.0745	MLR1009

Based on the SCADA data in Table V, the candidates for the fault section are estimated and results are listed in Table VII. Based on both the SCADA data in Table V and relay data in Table VI, the candidates for the fault section are estimated and the results are listed in Table VIII.

TABLE VII. CANDIDATES FOR ESTIMATED FAULT SECTIONS BASED ON SCADA DATA

Candidate No.	Fault Section	Truth Degree Value
1	B04	0.855
2	B09	0.855
3	L0409	0.513

TABLE VIII. CANDIDATES FOR ESTIMATED FAULT SECTIONS BASED ON SCADA DATA AND RELAY DATA

Candidate No.	Fault Section	Truth Degree Value
1	B04	0.882
2	B09	0.882
3	L0409	0.618

As shown in Table VII and Table VIII, besides the bus B04 and the bus B09, on which faults actually occur, the transmission line L0409, which has no fault, is included in the candidate set. The transmission line L0409 has a far smaller truth degree value than the other two candidates, which indicates small possibility of fault occurrence. The truth degree values of the candidates based on both the relay data and SCADA data are higher than those based on only the SCADA data.

V. FAULT LOCATION (FL)

Transmission lines occasionally suffer from faults which are generally caused by several random and unpredictable reasons. Protective device (relay) senses these faults and isolates the faulty line as soon as possible. Distance relays used for transmission line protection give some idea about the fault location, but they may over-reach or under-reach due to several reasons, such as prefault loading, fault resistance etc. To restore service, the accurate location of the fault should be known to help the maintenance crew find and repair the faulted line as soon as possible.

When fault appears different IEDs such as DPRs and DFRs sparsely located in substations will be automatically triggered by the fault and will record corresponding current, voltage and status signals. These recorded quantities can be used along with the data collected by SCADA to predict the location of transmission line fault accurately.

Transmission line fault location approaches can be broadly classified into two categories [24]:

- Phasor based using fundamental frequency component of the signal and lumped parameter model of the line.
- Time-domain based using transient components of the signal and distributed parameter model of the line.

The phasor based methods can be subdivided into another two broad classes 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.

Apart from these methods and their variants, artificial intelligence based methods are being widely used to locate transmission line faults [16, 25-28].

A. Optimal Fault Location Algorithm (OFLA)

Typical power system contains several thousands of transmission lines. Installation of recording devices at each transmission line is very expensive and it is not used in practice. Installing DFRs in critical substations is a common practice. Although protective relays exist in every transmission lines, most of them may still be electromechanical and they do not have capability to record measurements. As a result, in some cases it may happen that there are no recordings at all available close to a fault. Thus depending on the availability of data, different fault location algorithm should be used to get the most accurate result.

Depending on the nature and location of the measurements, the following FL algorithms are used:

- Two or multiple-ended time-domain synchronized sampling [29]
- Two-ended phasor-based asynchronized sampling [30]
- Single-ended phasor-based [31]
- System-wide sparse measurement [32]

The flowchart of the optimal fault location algorithm (OFLA) [33] is shown in Fig.8.

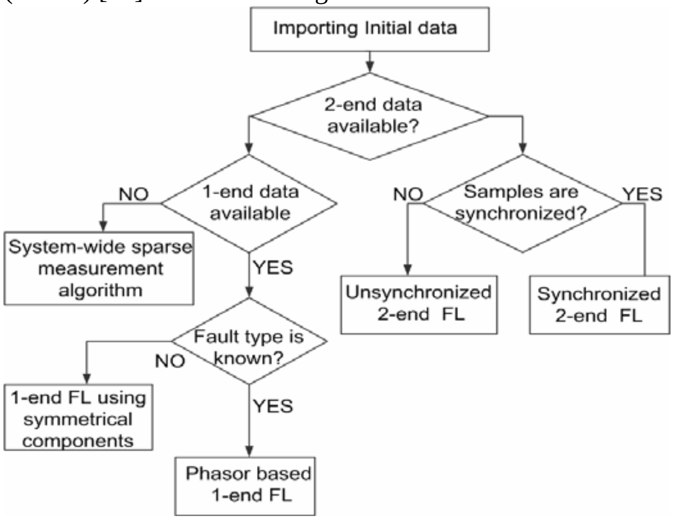

Fig. 8. Flowchart of Optimal Fault Location Algorithm

B. Data Requirements

The detailed description of system and field data needed for OFLA application is listed in Table IX. The static power system is modeled using PSS/E. To tune the power grid with pre-fault data, SCADA PI-Historian data is used. The visualization of OFLA is implemented using the Power World Retriever software, which can retrieve information from central repository.

The field recorded data (DFR data) should follow the COMTRADE format. Using this format, the measured data, configuration, data and interpretation files should be described. The DFR data contains analog and digital sample values for all input channels for a specific substation. The configuration data contains information for interpreting the allocation of measured data to the equipment in substation. The interpretation file for each substation represents the correlation between the nomenclature used in DFR files and those used in PSS/E file. These interpretation files should be modified frequently to reflect the DFR configuration or system model changes. The DFR recorded data supplied in native DFR format are converted to COMTRADE file using DFR Assistant software [34] which can generate an analysis report (containing the type of fault and a possible faulted line) in addition to generating the COMTRADE files.

C. Implementation

OFLA updates power system status with retrieved data, processes new event files, decides the most suitable FL algorithm and executes it. The output of the software is a fault report which can be used in a visualization module to generate Visual-Interactive-Distributed (VID) Spreadsheet, providing view into physical environment surrounding exact location of the fault and also views of involved equipment [33].The architecture of the OFLA is shown in Fig.9.

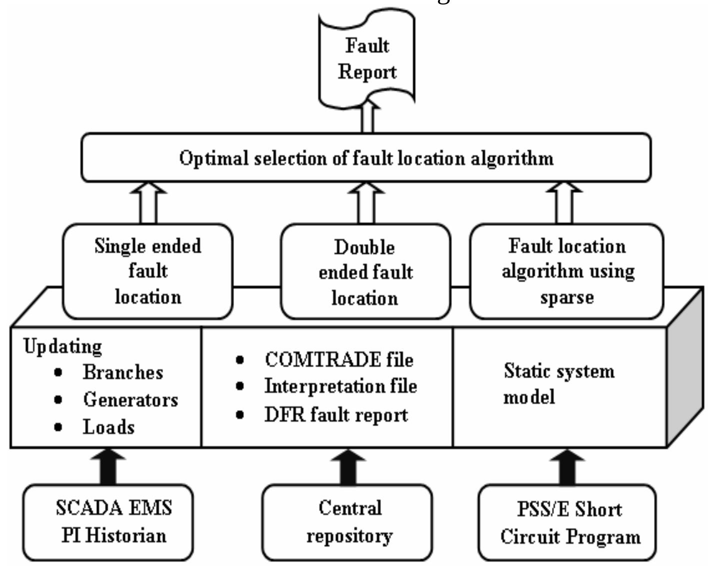

Fig. 9. Architecture of Optimal Fault Location Algorithm

Implementation of OFLA is evaluated for the following issues: using varying number of DFR files, specifying the search region, using preprocessed fault location estimation, using different quantities for the match between measured and simulated data, evaluating differences in the accuracy when different input data are available and different assumption are satisfied etc. These different options may produce different results. Test activities are conducted on the data collected from a real life electric power system [35-36].

TABLE IX DATA REQUIRED AND RELATED SOURCES FOR OFLA

Type of Data	Function Module	Detailed Data	Related Source	Description
System Level	Power Flow Analysis	Power Flow Raw Data	Input Data Files for PSS/E (*.raw)	This file contains power flow system specification data for the establishment of a static system model. This data is used by PSS/E to run the power flow analysis.
	Tuning to Static System Model	SCADA PI Historian Data		This file contains the latest load, branch and generator data to tune the static system data with the actual pre and post fault conditions
	Short Circuit Study	Sequence Impedance Data	Input Data Files for PSS/E (*.seq)	This file contains the negative and zero sequence impedance data needed for short circuit study. It is used by PSS/E to add the impedance data to the case of interest.
Local Level (Field data)	Optimal fault selection algorithm	Recorded Data during Faults	DFR Configuration (*.cfg) and Data (*.dat)	These files are the fault events to be used by Optimal Fault Location algorithm.
		Substation Interpretation Data	Interpretation Data (*.int) for each Substation of interest	The "Interpretation File" contains information that relates the channel numbers to the monitored signals. It also represents the correspondence between the designations used in the DFR files and those used in the PSS/E file.

VI. CONCLUSION

This paper discusses the performance characteristics of the substation IED data measurement chain by focusing on industry standards for the instruments used. It also focuses how efficiently substation IED data along with the traditional SCADA data and other available data can be integrated to enhance certain power system functions by automatically retrieving information from substation database. Use of integrated data is discussed using two illustrated examples: Optimal Fault Location Algorithm and Intelligent Alarm Processing Algorithm. In both of the examples, implementation and visualization aspects are discussed.

It can be concluded that major enhancements in performance of new applications can be achieved by integrating IED and other data, but accuracy of the data has to be carefully assessed before the integration is performed to make sure the applications are not adversely affected by mixing data with different accuracy obtained by different IEDs.

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