Merging PMU, Operational, and Non-operational Data for Interpreting Alarms, Locating Faults and Preventing Cascades

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Abstract

With the development of synchronized sampling technique and other advanced measurement approaches, the merging of various substation data to be used in new applications in the EMS solutions has not yet been explored adequately. This paper deals with the integration of time correlated information from Phasor Measurement Units, SCADA and non-operational data captured by other intelligent electronic devices such as protective relays and digital fault recorders, as well as their applications in alarm processing, fault location and cascading event analysis. A set of new control center visualization tools shows that the merging of PMU, operational and non-operational data could improve the effectives of alarm processing, accuracy of fault location and ability to detect cascades.

1. Introduction

Nowadays, most of the substations are equipped with Intelligent Electronic Devices (IEDs) which can collect huge amounts of data in addition to performing their other intended functions. These IEDs include digital protective relays (DPRs), digital fault recorders (DFRs), phasor measurement units (PMUs), circuit breaker monitors (CBMs), power quality monitors (PQMs), remote terminal units (RTUs), etc [1-3].

Traditionally, RTUs constitute data acquisition part of a supervisory control and data acquisition (SCADA) system, which is the main infrastructure for monitoring and operating power system. The data continuously collected by SCADA is called "operational" data. Other types of IEDs, such as DPRs and DFRs are collecting data only when a disturbance occurs, and this data is called "non-operational" data. The "non-operational" data collected by DPRs and DFRs plays an important role in power system alarm processing and fault analysis. PMUs are unique devices in that they collect synchronized phasors continuously, but this data has not yet been fully integrated with SCADA data. Hence, this new data is typically referred to as "situational awareness" data. In all of the above cases, collected data may be used to enhance Energy Management System (EMS) functions, and in that sense collectively the mentioned data may be called "extended SCADA" data. Integration of substation "non-operational" and "situational awareness" data with the traditional "operational" SCADA data collected by RTUs into the "extended SCADA" database to be used for new applications in the EMS solutions is not yet explored adequately [1, 4-7].

With the development of flexible electricity market operation under the deregulation rules, power system became more stressed and power network security and reliability criteria became more complex. Power systems are exposed to all kinds of disturbances. Under this situation, new tools such as intelligent alarm processor, optimized fault location and cascading event analysis [8-12], which take full use of data coming from PMUs, SCADA and other IEDs, have been proposed to help operators better analyze and control the system.

Table 1 provides a summary of the data deployed in these three applications as well as their outputs expected to be presented to control center operators.

Table 1. Requirements Specification for Applications

Applications	What to Display	Data Deployed
Intelligent Alarm Processor	1. Processing of alarms; 2. Analysis result; 3. Suggested actions; 4. Additional information.	Circuit breaker control signals; SCADA measurements; Synchrophasors; Other alarm signals.
Optimized Fault Location	1. Estimated fault section (Terminal bus numbers); 2. Fault location within the estimated section; 3. Exact fault type.	IED samples of voltages and currents; Synchrophasors; SCADA measurements.
Cascading Event Analysis	1. Cascade detection; 2. Cascade classification; 3. Suggested actions.	Synchrophasors; IED samples; SCADA measurements

This paper starts with the investigation of what is involved in data merging, and then continues with descriptions of the applications that use data merging. Next, the control center visualization tools which take use of data and applications are introduced. Finally the data/information exchange structure is explored. Conclusions are given at the end.

2. Merging of the Existing Data Sources

The integration of PMUs, operational and non-operational data remains a challenge for several reasons. The diversity of data formats is one major problem. Non-operational data usually comes in the COMTRADE data format and IEC 61850 object model data standard for IEDs that are IEC 61850 compatible, whereas the data collected from PMUs follows the format for synchrophasors [4-6]. In addition, data may be further formatted using the File Naming Convention Standard [7]. This makes the data merging a tedious task that requires merging of various formats before deploying them in applications. The merging of existing data sources and their applications is demonstrated in Fig. 1.

While it has been proven through some recent field demonstrations by utilities and vendors that synchrophasor measurements have capability of tracking the impact of low frequency oscillations, as well as power system area frequency and angle separation, which enhances awareness of system operators, it remains an issue how user interfaces that will aid operators in making decisions should be incorporated in the existing interfaces for SCADA functions. The merging of various data sources allows implementation of a new generation of control center software aimed at automated fault location and visualization of fault disturbance consequences. The visualization tool proposed in this paper seamlessly incorporates time correlated information from PMU, SCADA and non-operational data. This results in intelligent operator tools for viewing results from alarm processing, fault analysis and cascading analysis, which increases the effectiveness of power system monitoring and reduces the time needed to make decisions.

The integration of data sources and the proposed control center visualization tools is shown in Fig. 2.

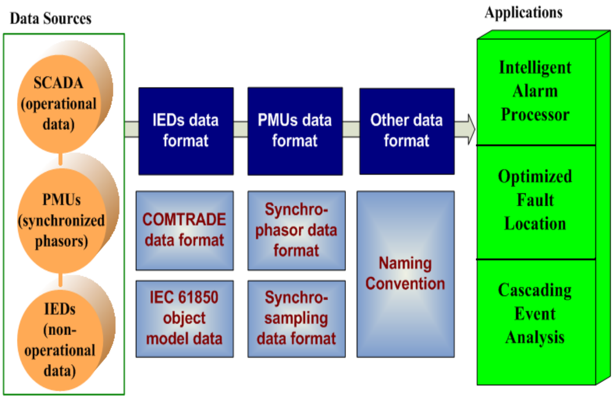

Figure 1. Data Merging and Applications

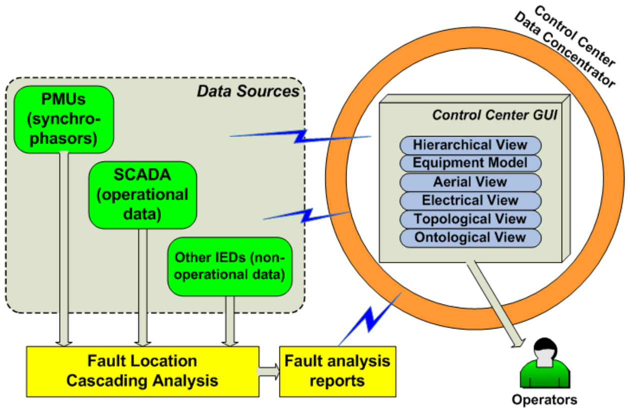

Figure 2. Control Center Visualization Tools

As shown in Fig. 2, input information such as raw samples, phasors, alarms, event files, oscillography files, etc. from PMUs, SCADA and other IEDs (e.g. DPRs and DFRs), together with automated analysis reports are collected, converted to actionable information and then sent to the control center graphical user interfaces (GUIs). After internal information processing, the graphical software will display several types of views, as outputs, using six visualization modules. The details of these modules will be explained in Section 3.

3. Applications Using Data Merging

3.1. Intelligent Alarm Processor

With the growth of power system complexity, a major disturbance could trigger hundreds or even thousands of individual alarms and events, clearly beyond the ability of any control center operator to handle [8]. To adapt to the new situation, a new

Intelligent Alarm Processor (IAP) has been developed to aid operators recognize the nature of the disturbances [9]. The application structure of this IAP is shown in Fig. 3. Data are collected from PMUs and other IEDs at the substation level. A wide area network (WAN) is utilized as communication link between substations and the control center. A real time database is set for storing and updating data. The different types of data are merged there. Alarms are then generated and processed at the control center engineering office. Here a Petri Net Logic algorithm is used for alarm processing. The algorithm details of this Petri Net Logic could be found in [9]. Once the alarms are prioritized and processed, the analysis results can be conveyed to the control center operators to handle the system conditions according to the recommended actions.

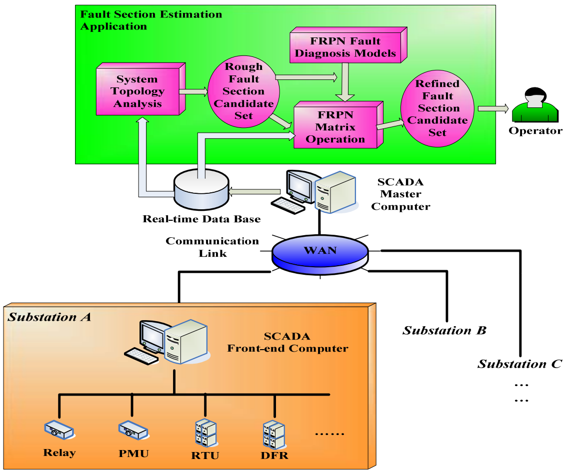

Figure 3. Intelligent Alarm Processor

3.2. Optimized Fault Location

Once a fault event in power system occurs, different IEDs automatically recognize this abnormality. It is essential that accurate information about fault location and its nature is provided as fast as possible. Various fault location algorithms have been presented in the literature in the past [10-12]. The spatial and temporal considerations indicate that there is no universal fault location algorithm suitable for all situations [1, 3]. In order to be able to evaluate which algorithms are applicable for a given fault event, different data sources (measurements) have been utilized and the idea of Optimized Fault Location (OFL) approach which takes into account both temporal and spatial considerations has been proposed [10].

Fig. 4 shows an implementation of the optimized fault location. Data collected from different measurement devices are merged at the bottom layer.

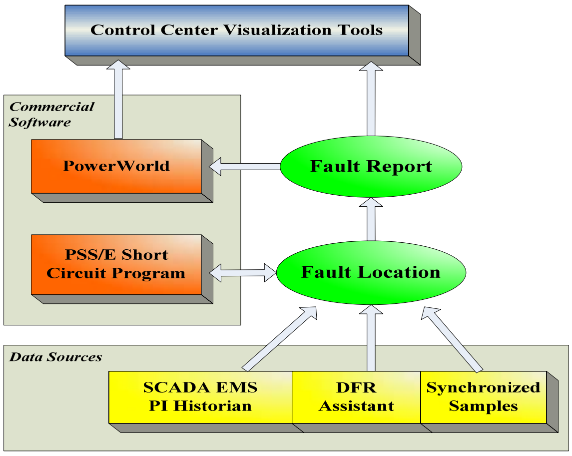

Figure 4. Optimized Fault Location

Then the selected fault location algorithm is executed, assisted by commercial data storage and viewing software, to obtain the fault location report.

Once the fault location is calculated, the fault analysis report is effectively presented to operator. Knowing the real-world environment around fault location and construction of involved equipment enables utility staff to repair fault quickly and efficiently. Designing user interfaces that can effectively convey the results of fault analysis remains a challenge in the utility industry because the analysis leading to the conclusions is rather complex and operators are not trained to interpret additional information. To overcome the above complexities that may overwhelm the operators, the user interface has to offer a compact view of the course of events with clear suggestion what the course of action should be. This is not available in today's user interface designs and requires new solution as proposed in this paper.

3.3. Cascading Event Analysis

Cascading outage, especially the large-scale cascading outage, will cause great economic loss to utility companies and other businesses and potentially devastating impact on people's life. The causes for large-scale blackouts are quite unique due to the complexity of power system operations. It appears that relaying problems and inadequate understanding of unfolding events are two major contributing factors in inability to predict or prevent cascading events.

Considering the above factors, a novel interactive scheme of system/local monitoring and control tools for cascading event analysis was recently introduced. The detailed techniques about how to detect, prevent and mitigate cascading events have been discussed in literature [13-16]. The local analysis tools take full use of data coming from PMU and other IEDs, including synchronized phasors and synchronized samples. Fig. 5 shows the diagrams of fault location and detection tools for the cascading analysis.

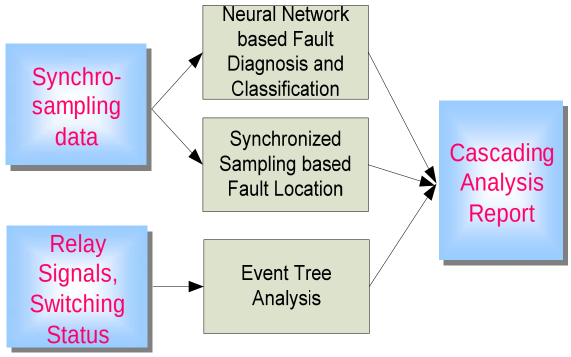

Figure 5. Cascading Event Analysis

The neural network based classifier is used to detect and classify the disturbances that require protective relay action. Comparing with traditional method, neural network based fault diagnosis algorithms usually uses the time-domain voltage and current signal samples directly as patterns instead of calculating phasors. The technique compares the input voltage and current signal sample assembles with well-trained prototypes instead of predetermined settings. Thus accuracy of phasor measurement and relay setting coordination are not an issue in neural network based algorithms as they are in the traditional methods. This provides an advantage of the proposed solution versus the traditional methods. Voltage and current signals from the local measurement are formed as patterns by certain data processing method. Thousands of such patterns obtained from power system simulation or substation database of field recordings are used to train the neural network offline and then the pattern prototypes are used to analyze faults on-line by using the Fuzzy K-NN classifier. The use of multiple neural networks can also enhance the capability of dealing with large data set. [17]

Synchronized sampling based fault location (SSFL) algorithm, as demonstrated in Fig. 6, uses raw samples of voltage and current data synchronously taken from two ends of the transmission line. Compared to the fault location algorithms that use one end or two end phasor data, synchronized sampling based fault location algorithm makes no assumptions about fault condition or system operating state, so it is immune to power swing, overload, and other non-fault situation. The sampling synchronization may be achieved by using Global Positioning Satellite (GPS) receivers, which generate the clock time reference for data acquisition equipment. This gives an accuracy and robustness advantage of the proposed scheme vs. the traditional one [12].

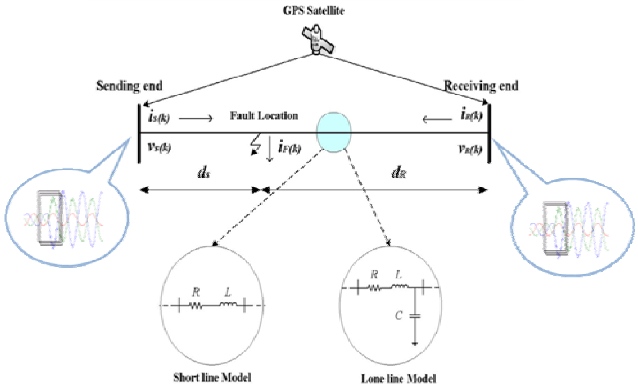

Figure 6. GPS-based SSFL

As already mentioned, compared to the fault location algorithms that use one or two end data, SSFL makes no assumptions about fault condition and system operating state. Therefore it is less affected by those factors and keeps the useful information in the waveform to locate the fault precisely. Table 2 shows 10 cases of the results for SSFL algorithm [14]. For all the tests, the maximum error for fault classification is 3.6992%; the minimum error is 0.0234%.

Table 2. Results of SSFL algorithm

	Fault Type	Fault Distance (mile)	Fault Resi-stance (Ω)	Fault Angle (°)	Calculat-ed Fault Location (mile)	Error (%)
1	CAG	85.2	3.1	199.9	85.25	0.0234
2	ABG	151.1	11.9	121.6	150.19	0.4706
3	ABCG	23.1	13.1	38.2	22.51	0.2870
4	AG	135.2	11.7	49.8	136.30	0.5693
5	CAG	116.2	1.3	217.0	115.61	0.3037
6	AB	38.3	15.1	3.8	37.48	0.3933
7	BCG	19.6	2.5	239.7	21.57	1.0016
8	CG	120.0	4.3	110.0	122.14	1.0656
9	AG	176.4	9.2	98.5	174.60	0.8917
10	ABCG	68.0	2.3	102.8	66.60	3.6992

4. Control Center Visualization

This section addresses a set of new control center visualization tools, which integrate PMU, operational (SCADA) and non-operational (other IEDs) data. The proposed visualization tool also incorporates options for integration of application modules that contains state-of-the-art alarm processing, fault location and cascading analysis approaches.

4.1. System Flow Chart

The overall implementation flow chart of the visualization software is shown in Fig. 7. Embedded in the flow chart are two types of logic: external logic and internal logic.

The external logic explains relationship between applications and GUI software, as well as their implementation sequence. The internal logic explains relationship and implementation sequence of various functional modules and user interfaces within the GUI software.

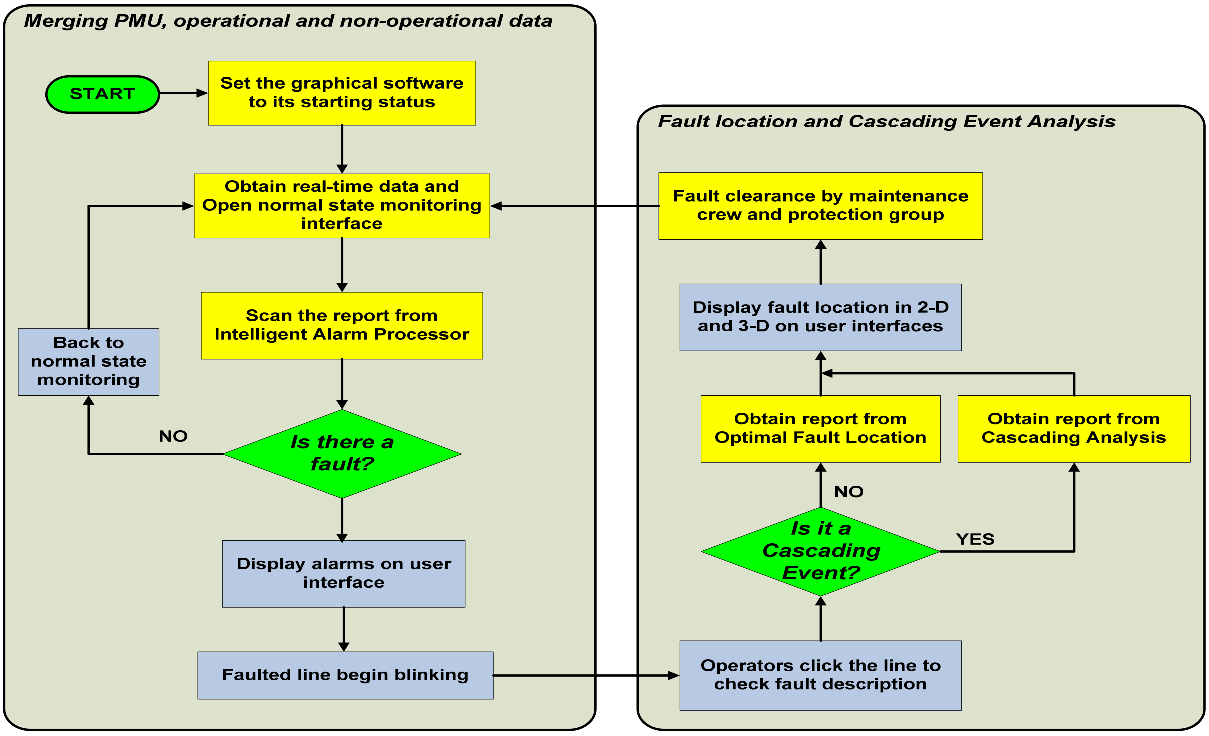

Figure 7. Visualization System Flow Chart

4.2. Visualization Tools

The proposed control center visualization system is depicted in Fig. 8. As specified in the figure, there are six modules incorporated in the proposed visualization tools: Equipment Model View, Aerial View, Electrical View, Topological View, Ontological View, and Hierarchical View.

- ***Equipment Model View***

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

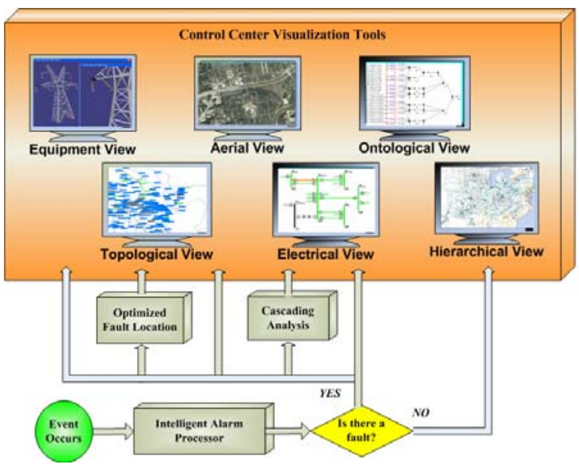

Figure 8. Control Center Visualization Tools

• ***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 [18, 19]. 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. One example is shown in Fig. 9.

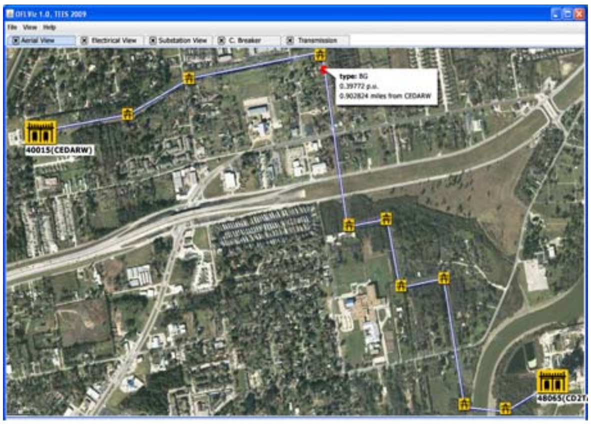

Figure 9. Aerial View

• ***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 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

4.3. Control Center Work Flow Management

The control center equipped with new visualization tools will now have two distinct features comparing with those of traditional EMS system:

- The substation data and extracted information are shared with different utility groups (protection engineers, dispatchers, maintenance technicians, etc.)making sure the data/information are presented in the form most suitable for a given group;
- Each group receives the best information since the origin of substation data becomes transparent to the users and what they receive is the best information obtained using all available data.

Each utility group will be equipped with a computer with GUI client installed. The clients together with the server are interconnected through a local area network. Operator is responsible for monitoring real-time system conditions. Other utility groups also receive information from client computers.

Once an event occurs, the visualization tools will inform operator immediately. Operator could then assign tasks to different groups according to the fault reports and recommended solutions. The maintenance crew will be requested to repair system components identified with accurate fault location while protection engineers will be asked to analyze the fault clearance sequence. The dispatchers will be required to re-dispatch the power generation and load flow to balance the whole system.

5. Implementation of Data Merging

When implementing the data merging, several requirements should be satisfied:

- A reliable data exchange structure should be defined;

- An effective data interpretation system should be utilized;
- Network interoperability should be maintained.

5.1. Data Exchange Structure

In order to efficiently exchange time correlated data from PMUs, SCADA and other IEDs, a data exchange system which possesses the following features is proposed:

- The Common Information Model (CIM), which is defined in IEC-61970 [20], is utilized as standard data modeling format;
- After converted to CIM format, metadata is stored to an XML file. Application modules use this file to carry out analysis. Outputs from all applications are also converted to CIM format for future use;
- XML file which contains outputs of applications is sent to control center server. The server is responsible for collecting and saving data files from applications and SCADA Historian database. It is also connected to client computers through LAN. Information exchanging between server and clients is completed within the network;
- The server and client computers are connected via Java Remote Method Invocation (Java RMI). The Java RMI provides for remote communication between programs written in the Java programming language [21];
- The proposed visualization tools are installed in all client computers. Once an event occurs in power system, clients will receive fault reports from the server. Analysis results of different applications are presented to the operator through GUIs which are incorporated in the visualization tools.

An entire data exchange structure between IEDs, substations, control center engineering office, utility groups, and other enterprise locations is demonstrated in Fig. 10.

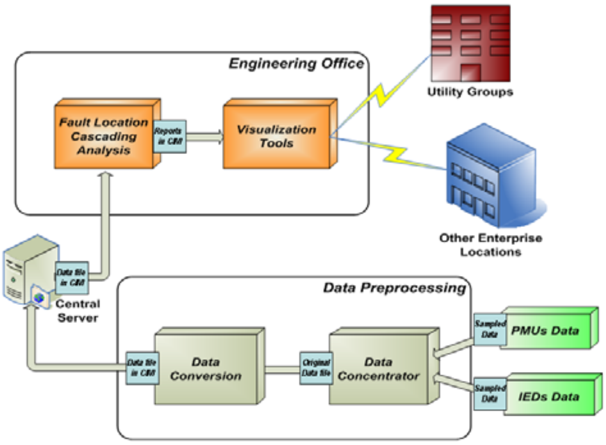

Figure 10. Data Exchange Structure

5.2. Data Interpretation

As demonstrated in Fig. 10, the PMU data, SCADA measurements and other IEDs data are collected by substation data concentrator. Since these data have different formats and contents, data preprocessing is required to convert original data and measurements into applicable data files. The data interpretation is necessary to execute this preprocessing, which is shown in Fig. 11.

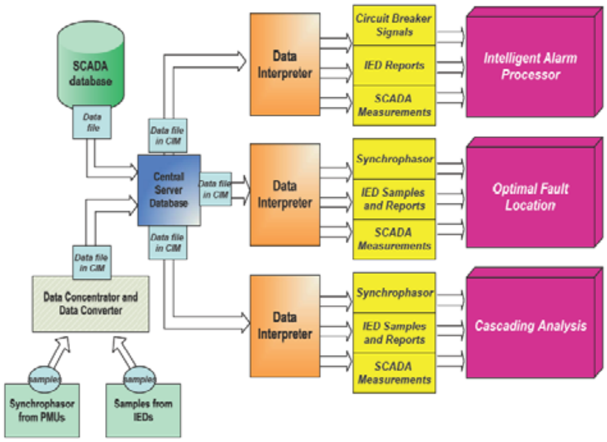

Figure 11. Data Interpretation

The data sent from control center concentrator is converted by data interpreter before they are sent to different applications. For Intelligent Alarm Processor, data is interpreted into applicable circuit breaker signals, IED reports and SCADA measurements. For Optimized Fault Location and other applications, data is interpreted into applicable synchrophasors, IED samples and reports, as well as SCADA measurements.

5.3. Network Interoperability

The implementation of data merging needs also to take into account the network interoperability. Several existing data communication standard are deployed to make the proposed data/application/visualization system implementation easier. As demonstrated in Fig. 12, at the substation level, IEC 61850 is deployed as the standard for intra-station data communication [5]. Ethernet is deployed for the purpose of inter-station data communication. At the control center level, IEC 61970 is the data communication standard [20].

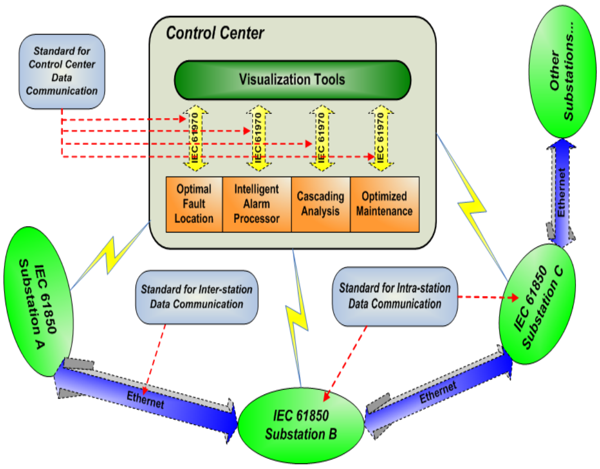

Figure 12. Network Interoperability

6. Conclusions

The purpose of this paper is to illustrate how the efficiency of alarm processing, accuracy of fault location and capability to analyze cascades may be improved by integrating PMU, operational and non-operational data. Several accomplishments have been reported:

- The integration of time correlated information from Phasor Measurement Units, SCADA and non-operational IEDs has been implemented;
- The merging of data sources for the use in the proposed applications has been specified;
- The data processing structure as well as inputs and outputs of each application have been demonstrated and compared to the traditional implementations.
- The integrated tools for control center visualization have been designed. Six different GUI modules have been specified.
- New work flow management approach which makes better use of information extracted from the source data has been suggested.
- Implementation considerations of data merging have been discussed: data exchange structure, data interpretation, and network interoperability.

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