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Implementation requirements for automated fault data analytics in power systems

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SUMMARY

This paper addresses implementation requirements for a fully automated substation data integration and fault analysis for power system transmission lines. The approach is based on measurements from substation intelligent electronic device recordings. The proposed architecture provides a transparent approach to substation data management, analytics functions, as well as the visualization of the integrated data and analytics results. When combined with an efficient communication and data collection scheme, the solution bridges the gap between traditionally separated non-operational and operational data. The fault analytics results, traditionally obtained through off-line manual process, can now be used in an automated way to support on-line decisions when operating or restoring the power system. The solution is open for further expansions and interfacing to third-party systems. The paper illustrates implementation examples and provides initial in-house and field test results. Copyright © 2014 John Wiley & Sons, Ltd.

KEY WORDS: smart grid; substation data integration; intelligent electronic devices; transmission line faults; power system fault location; intelligent systems

1. INTRODUCTION

Smart grid integrates advanced sensing technologies, and communications and control methods into the electricity grid [1]. The enormous expansion of computer and communication devices being deployed in the grid results in an "explosion" of data becoming available through field measurements in substations [2]. The data recorded by various intelligent electronic devices (IEDs) installed throughout the power system contains very valuable information about changes in analog measurements during disturbances and switching actions in the power system. The knowledge based on this information can be used to improve the decision-making process. This knowledge can be invaluable in facilitating the power system restoration after the fault or blackouts [3].

The field-recorded IED data is typically considered non-operational and used in manual after-the-fact analysis. In recent years, the large-scale deployment of IEDs resulted in a massive amount of field data that needs be collected, communicated, and processed in a timely fashion. In addition, several new challenges such as cyber–physical security, time-synchronized data storage, configuration management, and efficient visualization need to be addressed as well [4,5]. The key to efficient use of IED event data is implementation of automated data analytics solutions [6]. Automated fault data analysis and fault location calculation have significant places in developing a smart grid roadmap [7]. New trends and importance of automated fault analysis are addressed by recent activities of CIGRE as well [8].

Ideas for automated analysis of substation data are not new and it all started when first digital fault recorders (DFR) were installed [9,10]. One of the first practical expert system solutions based on DFR

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data was introduced in mid-90s [11]. There are solutions based on combining remote terminal unit (RTU) and DFR data focused on expert system evaluation of breaker contacts [12]. Elaborate use of expert systems to evaluate correctness of digital protective relay (DPR) operations has been explored, as well [13]. An illustration of how the data from new IED devices such as circuit breaker recorders (CBR) can be automatically analyzed is given in [14]. Besides expert systems, there are various efforts in how to utilize neural networks and fuzzy systems for fault detection and classification [15,16]. Most of the explored and existing solutions are limited to one type of device, specific vendor, model, and vintage. The solutions typically involve a complicated set of internal settings, long training, or special methods for tuning.

The requirements for the solutions targeting specific types of event-triggered IEDs such as DFRs, DPRs, and CBRs have been known for a while [17]. This paper focuses on the practical approach to automated substation data integration and fault analysis for power system transmission lines. Such a use of substation data requires transparent and more robust computations that can be applicable to a combination of various event-triggered IEDs. The background section of the paper gives an introduction to various event-triggered devices and explores the opportunity to utilize the non-operational data in support of decision-making processes used for real-time operations. Section 3 provides insight into the fault data analytics, applicable to transmission systems, and outlines the requirements for signal processing, expert system, and fault location calculation. Section 4 discusses the solution architecture and real-life implementation. Verification and test results are provided in Section 5. Conclusions and references are given at the end.

2. BACKGROUND

Traditionally, when operating electric power transmission systems, the decision-making process relies on the measurements data collected by RTUs of supervisory control and data acquisition (SCADA) system. These measurements include analog signals (bus voltages, power, frequency, etc.) and digital contacts (breaker status), which are being scanned continuously every few seconds. This information is communicated to the energy management system, visualized, and used by the grid operators. The DFRs and other event-triggered IEDs continuously monitor analog and digital signals, but only capture records when certain triggering thresholds criteria are met. The recordings typically cover 0.3 to 1 s time window (20 to 60 cycles) and contain high frequency signal components by using up to 10 kHz sampling rate. The recordings typically contain a few cycles of the pre-trigger and over a dozen cycles of post-trigger data. The idea is to capture monitored waveforms around a power system disturbance inception. DFR records are kept in the memory of DFR device and subsequently uploaded to a master station computer in the central offices via some communication scheme. It is not unusual that this communication link still uses serial protocols, telephone lines, and modems. The analysis of DFR data is typically done manually, after-the-fact, by a protection and/or maintenance engineer. This analysis is not performed in real time and therefore the data is considered to be non-operational. Also, DFR devices are not present in all substation, but rather sparse in the system covering important or critical substations. With the new approach, measurements from recordings are processed automatically and used as operational data.

Newer versions of DFRs, being deployed in recent years, include GPS time synchronization of sampling clocks resulting in synchronized samples, much better recording resolution, and more elaborate communication capabilities [18]. The majority of modern IEDs, such as DPRs, CBRs, and power quality meters (PQMs), mimic the recording function of DFRs, which enables better coverage of the grid events. Almost every substation nowadays has some form of IEDs and there is a trend to equip substations with faster communication channels. All of this is leading to a more improved monitoring and real-time availability of the substation data recorded at the time of faults or other disturbances. It is not uncommon that a single disturbance event is being recorded by several IEDs from one or more substations. This creates a problem as utilities do not have enough manpower to process all this data in an efficient way. Automating the substation data collection is the first step to enable efficient fault data analytics, which in turn allows better decision making [19].

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3. POWER SYSTEM FAULT ANALYSIS

This section describes various techniques needed to perform a comprehensive fault data analysis. An example of a field-recorded disturbance event that corresponds to a phase A to ground fault in a transmission line is given in Figure 1. Such a recording, based on common practice in using DFRs, may contain several analog and digital measurements across the entire substation. Some other IEDs, such as DPRs, may contain only a limited number of analog measurements corresponding to a single transmission or distribution line.

3.1. Signal processing

Signal processing of the event-triggered fault data is quantifying current and voltage signals by calculating phasors. Phasors are estimated from the corresponding signal samples. For example, an arbitrary sinusoid, say $i(t)$, is represented by a phasor I. A phasor is a complex number defined by its real $\mathrm{Re}\{I\}$ and imaginary part $\mathrm{Im}\{I\}$, or alternatively by its phase and amplitude. The calculation of the phasor parameters may be done using Fourier analysis. The formulas for calculating the real and imaginary part of a phasor given below are well known (1).

$$\mathrm{Re}\{I\} = \frac{2}{N}\sum_{n=0}^{N-1} i\left(\frac{n}{Nf_0}\right)\cos\left(\frac{2\pi n}{N}\right), \mathrm{Im}\{I\} = \frac{2}{N}\sum_{n=0}^{N-1} i\left(\frac{n}{Nf_0}\right)\sin\left(\frac{2\pi n}{N}\right) \quad (1)$$

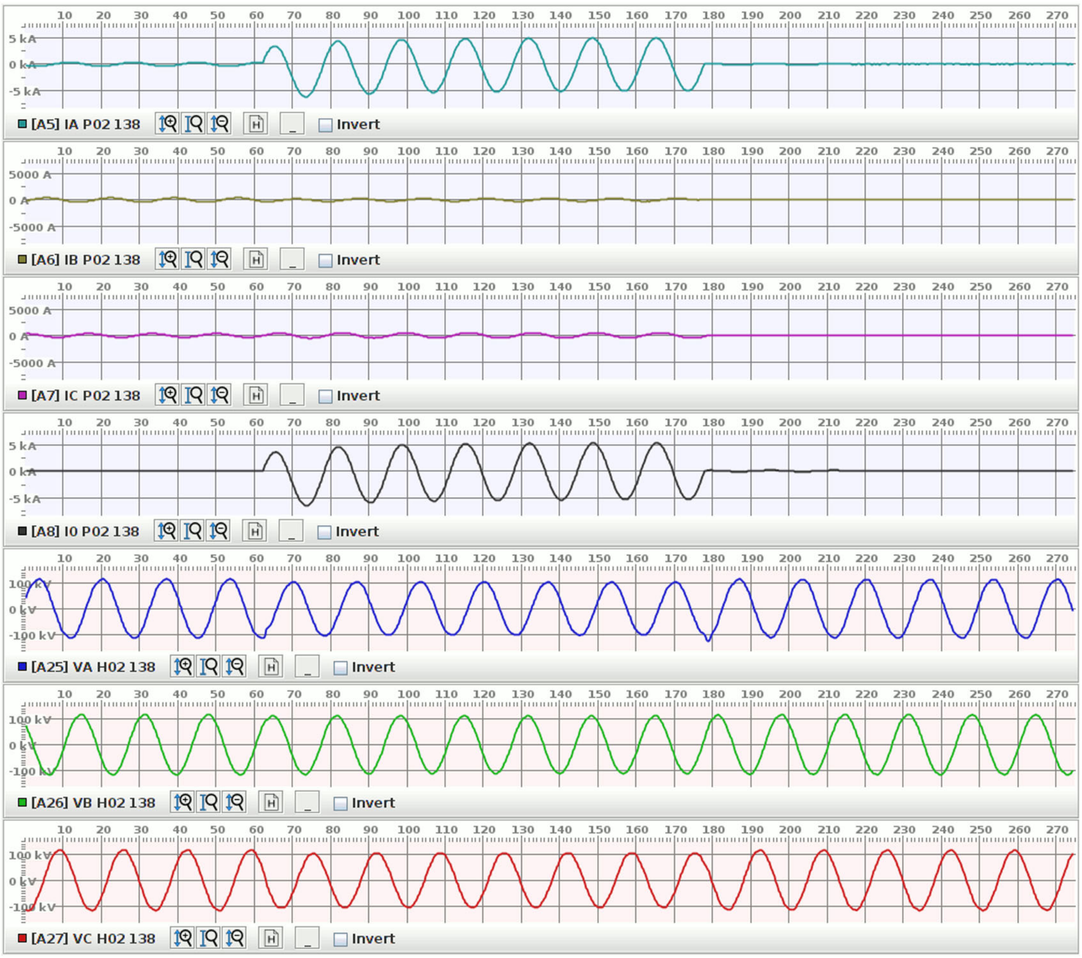

Figure 1. DFR event record triggered by an A-G fault on a transmission line.

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Number N is an integer equal to the ratio of the sampling frequency f_s and system frequency f_0. The samples of the corresponding signal $i(t)$ are equal to $i(n/Nf_0)$. They are taken from a one-cycle long window of samples. The phasor amplitude and phase can be then calculated from its real and imaginary parts of a complex number by the well-known formulas. The clearance time for fault events in transmission lines is typically 4 to 6 cycles [20]. However, new protection equipment is getting quicker and the fault clearance time can get as low as 1–2 cycles. The shortest fault clearance we experienced with the solution in the pilot installation was between 2 and 3 cycles. With the available quality of the IED data, 16-bit A/D vertical resolution with sampling rates 32 samples/cycle for DPRs and 96 samples/cycle in DFRs, the given phasor estimation worked satisfactory and all of the fault events were correctly detected and classified. For shorter fault clearance times, or situations with a higher or variable fault resistance, implementation of more detailed and faster phasor estimation may be used [21,22].

Identifying the faulted circuit is the first step when processing an event record and the focus is to identify a current signal with highest disturbance. This step is necessary for event records coming from IEDs that can monitor multiple circuits, which is common situation with DFRs. It is accomplished by splitting recorded waveforms into cycles of the fundamental frequency and determining their corresponding phasor values. These values are used to form a matrix of current amplitudes (I_{dist}) for each recording channel and its corresponding cycles (2).

$$I_{dist} = \begin{bmatrix} I_{11} & I_{12} & \dots & I_{1q} \\ I_{21} & I_{22} & \dots & I_{2q} \\ \dots & \dots & \dots & \dots \\ I_{p1} & I_{p2} & \dots & I_{pq} \end{bmatrix} \tag{2}$$

The variable p is the number of analog channels representing electric current signals, and each signal waveform contains q cycles, which is defined by the length of the waveform recording. The I_{dist} matrix is then scanned row by row and searched for highest change in two successive cycles. The row with the highest change corresponds to the electric current signal with the highest disturbance. If there are no significant changes, it is assumed that the recorded file was not triggered by a fault but by some other change in analog or status signals. Determining the faulted circuit candidate is based on the assumption that each monitoring circuit (i.e. transmission line, power transformer) is being defined by a set of analog and digital quantities that are being measured and recorded. The quantities of interest are three-phase currents and voltages, as well as status signals such as protective relay trips, and circuit breaker auxiliaries. The channel index of the analog signal with the highest disturbance is used to look up the corresponding circuit. This allows the analytics to focus on a subset of signals associated to the identified affected circuit. In case of a DFR, for example, this means that identification of the faulted circuit reduces the number of signals that are going to be further processed.

Finding disturbance start/end times is applied to the set of signals associated with the faulted circuit. It can be simply done by adopting the times rounded to cycle intervals we used in I_{dist}. In the solution presented in this paper, it was further improved by performing sample by sample search from the beginning of the file towards the disturbance start, and from the end of the file towards the end of the disturbance. The search is focused on the current signals belonging to the affected circuit identified in the previous step. This is a crucial part of the signal processing as it allows us to split the event record time window into three regions: (i) pre-disturbance, (ii) disturbance, and (iii) post-disturbance (Figure 2). It is important to note that some IEDs, depending on the type, model, and vintage, may provide additional information such as the disturbance start and end times and that information may be utilized as well.

Expert system pre-processing consists of calculating signal features for each time region. A typical set of signals that are used for automated fault analytics for a transmission line is given in Table I. For each signal we calculate its pre-fault, fault, and post-fault value. For analog signals this is done by calculating its phasor value in the middle of each region (please refer to Figure 2). This function is dependent on the correct detection of the start and end of the disturbance, which can be a challenge when the signals are noisy and the fault clearance time is very short.

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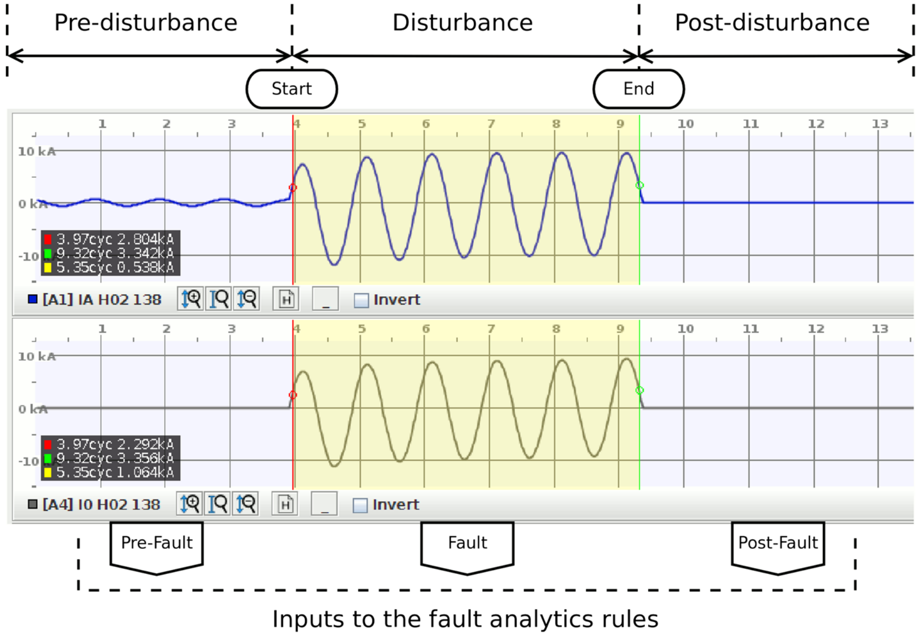

Figure 2. Identifying the disturbance start/end times, positioning the cursors.

Table I. List of signals used for automated fault analysis.

Signal	Description	Type
I	Line currents: 3 phases or 2 phases and zero sequence	Analog
U	Bus voltage: 3 phases, or 2 phases and neutral	Analog
CB1	Bus (primary) circuit breaker status	Digital
CB2	Middle (secondary) circuit breaker status	Digital
R1	Primary relay trip status	Digital
R2	Backup relay trip status	Digital
TCR	Blocking signal received status	Digital
TCT	Blocking signal transmitted status	Digital
TCFR	Breaker failure signal received status	Digital
TCFT	Breaker failure transmitted status	Digital

3.2. Expert system

The expert system (ES) for the fault data analysis implements two main functions: (i) fault detection and classification and (ii) system protection operation evaluation. The activity diagram for the fault detection and classification is depicted in Figure 3. The expert system executes the knowledge rules, based on the pre-defined thresholds, by matching analog signal quantities for the pre-fault, fault, and post-fault time regions with the expected behavioral patterns (Section IV in [23]). By doing so, the expert system is “mimicking” logic applied by fault analysis experts. The actual implementation described in this paper uses customized ES rules and behavioral pattern thresholds tuned to enable the use of data obtained from variety of DFRs and DPRs [24].

The ES rules sometimes depend on each other. For example, the ES first checks if the IED record corresponds to a fault disturbance and then checks if the fault is a ground fault. With those facts established, the ES performs the fault classification. An example pseudo-code implementing a fault classification rule is given in Figure 4. The rule is checking if the fault is matching with a phase A to ground pattern. In the given example, phase A fault current is expected to be at least 1.3 times higher than its pre-fault value. Throughout the fault, phase B and C currents are expected to be less than 0.75 times faulted phase, and so on. The outcome of the rule is recorded for later use, and its log is saved to the analysis report.

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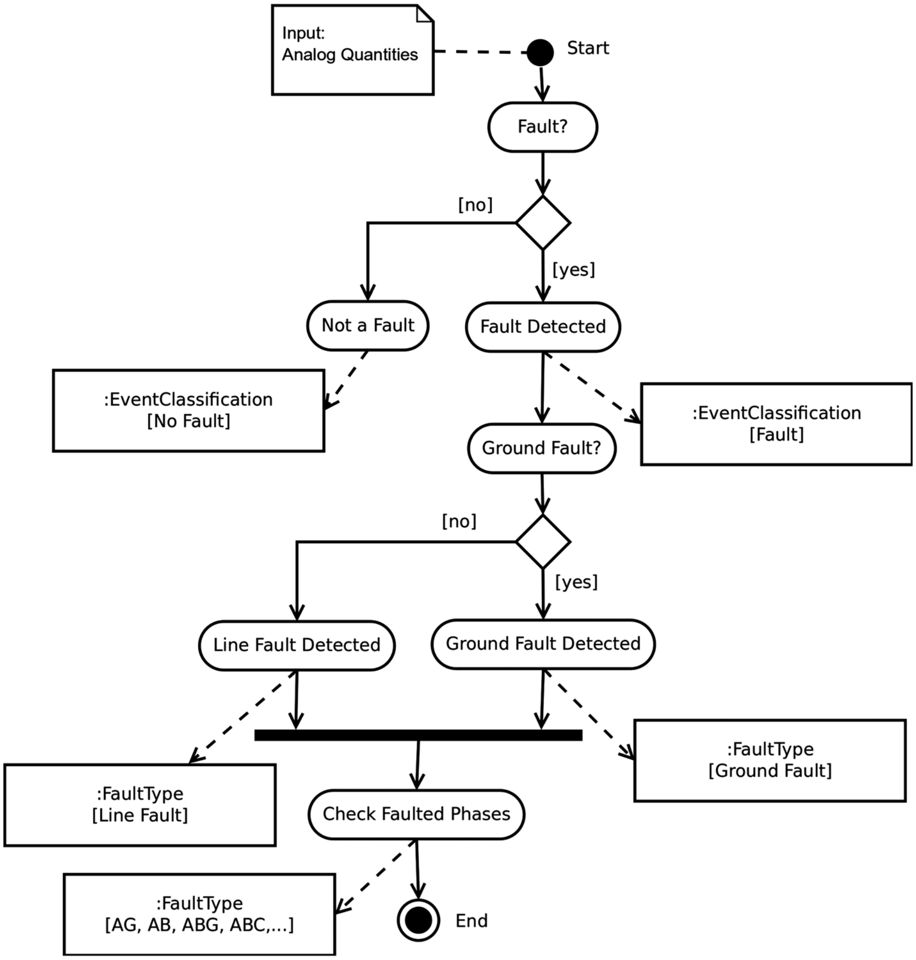

Figure 3. Fault detection and classification activity diagram.

```
// Rule: Phase A to Ground Fault
// Input(s): prefault and fault phase currents and voltages
if (notDisturbance = false
   and groundFault = true
   and faultCurrentA  >  1.30 * prefaultCurrentA
   and faultCurrentB  <  0.75 * faultCurrentA
   and faultCurrentC  <  0.75 * faultCurrentA
   and zeroSeqCurrent >  0.20 * faultCurrentA
   and faultVoltageA  <  0.96 * prefaultVoltageA
   and faultVoltageB  >  0.85 * prefaultVoltageB
   and faultVoltageC  >  0.85 * prefaultVoltageC
   and faultVoltageAB ≈  faultVoltageCA)
then
   faultType := A-G;
   addLineToReport("The event is a phase A to ground fault!");
endif
```

Figure 4. Pseudo-code snippet for A-G fault classification rule.

Once the fault has been detected and classified, the expert system continues with applying the rules for system protection operation evaluation. As it can be seen in Figure 5, the rules evaluate if the line was opened after the disturbance (current signals around zero) and that information is combined with the fault detection and classification in order to assess whether the protection clearing was successful. The rules for protection evaluation can be significantly enhanced if signals such as relay trip, circuit breaker auxiliary, and protection scheme communication statuses are available. For example, breaker

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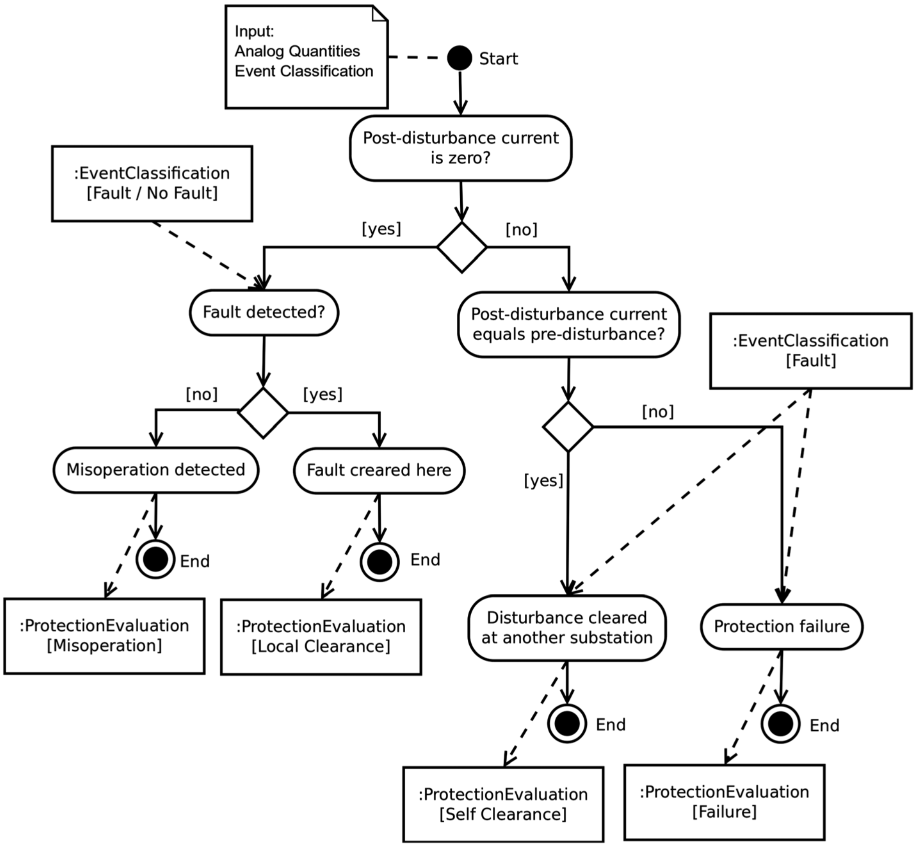

Figure 5. Protection evaluation activity diagram.

status "open" is matched with current reaching zero value immediately after the disturbance to confirm the protection operation. In addition, the timings of these digital signals may provide additional insight on how quickly relays or breakers operated and point out a need for maintenance in the case of slow breaker operation.

3.3. Fault location calculation

The system for automated fault data analytics should be designed in such a way that it allows for easy customization and addition of fault location methods and modules. The solution illustrated in this paper was implemented for transmission systems and we used phasor-based calculations per recommendations from IEEE Guide [25]. Other calculation methods for determining fault location on AC transmission lines can be utilized as well [26,27]. It is important to note that the proposed architecture allows integration and analysis of IED data coming from distribution systems. The approach using the apparent impedance for fault location in distribution systems can be used. This category of methods has been reviewed in [28]. Another example of a fault location method that can be applied to distribution systems is given in [29].

Single-end method uses the apparent impedance as seen looking into the measurements from one end of transmission line. A one-line diagram of a faulted transmission line is depicted in Figure 6. The line ends are denoted as S for sending and R for the receiving bus.

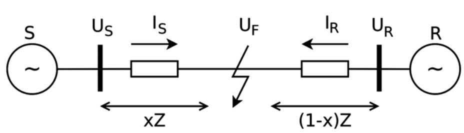

Figure 6. One-line diagram for a faulted three-phase transmission line.

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Based on the measurements from only the sending end the fault location estimate is calculated using the formula (3) as proposed by Takagi et al. [30]:

$$x = \frac{\mathrm{Im}\left\{U_S \cdot I''^{*}_S\right\}}{\mathrm{Im}\left\{ZI_S \cdot I''^{*}_S\right\}}, I''_S = I_S - I'_S \tag{3}$$

U_S and I_S are voltage and current phasors measured during the fault, Z is line impedance, and $I_S''^{*}$ used in the formula is a complex conjugate of the difference between line current measured at the sending end before the fault and during the fault. It is important to note that this method also requires knowledge of the fault type (A-G, B-G, AB, etc.), so it can only be performed after the expert system fault detection and classification selection are done.

Two-end method uses measurements from both the sending and receiving ends of the line. With the assumptions that the measurements from both ends are properly time synchronized and the extracted phasors from both ends use the same time reference, we can combine equations for determining $\boldsymbol{U}_F$ from both ends, namely S and R, into a single matrix Equation (4).

$$U_S - xZI_S = U_R - (1 - x)ZI_R \tag{4}$$

This matrix equation is equal to six scalar equations with only one unknown x, which can be calculated using any of those six equations. Two-end fault location estimation can be enhanced using the minimum least squares (MLS) method utilizing all six equations [31]. The MLS solution will not be an exact solution to any of the equations, but will minimize the error. The equations can be rewritten as Equation (5).

$$\begin{aligned} &Ax + B = E, \\ &\qquad A = -Z(I_S - I_R), B = U_S - U_R + ZI_R \end{aligned} \tag{5}$$

The MLS method minimizes $\boldsymbol{E}^T\boldsymbol{E}$ and the solution for the fault location estimate x can be found using matrix calculation given in Equation (6).

$$x = -\left(A^T A\right)^{-1}\left(A^T B\right) \tag{6}$$

This method gives very good results where the measurements from both ends of the line are available and where the measurements are correctly synchronized to the same time reference.

The goal in this paper is to define implementation framework that combines the fault analytics methods and techniques presented in this section into a fully automated solution that can be applied to event-triggered recordings from various types of substation IEDs.

4. IMPLEMENTATION ARCHITECTURE

The core of the implementation architecture for event-triggered data analytics is depicted in Figure 7. There are two main parts in the implementation framework: (i) the data warehouse (database), and (ii) four interface specifications. The data warehouse contains substation event data, configuration settings, and analytics results (output). Interface specifications define implementation rules for file format conversion (unification), access to the configuration settings, running of data analytics functions, and finally, access to the converted data and analytics reports.

Data warehouse — all the IED recorded data is meant to be converted to selected standard data format such as COMTRADE [32,33] and COMFEDE [34]. The file repository in the database should utilize a standardized file naming convention [35]. At present, it is most likely that the actual file repository integration requires combination of vendor-based and custom developed software modules in order to make sure that the records comply with the selected data format and naming standards. Besides the IED data, the database has to contain system configuration data that describes system components and their relationship (i.e. lines, buses, circuit breakers, switches, relays, CTs, VTs, etc.), as well as IED configuration with IED channel assignments and calibration to specific system components (line/bus voltages, line currents, status signals). The system configuration data enables automated IED data conversion into standard formats and integration into the database thus making

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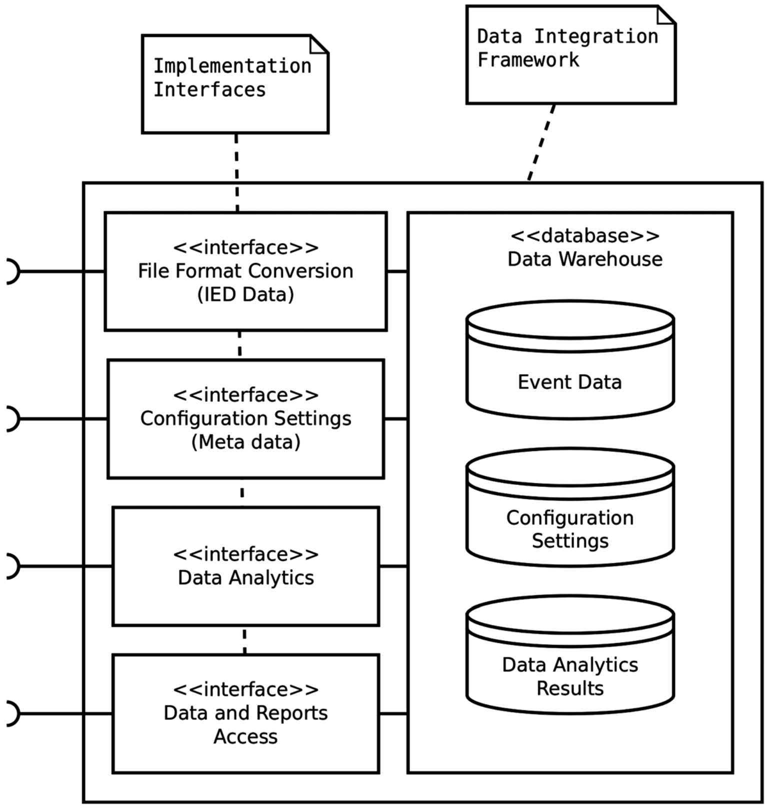

Figure 7. Implementation framework for event-triggered IED data analytics.

the data available for data analytics (software modules). Configuration settings, sometimes called the meta-data, are kept in readable, non-proprietary formats such as ASCII text and XML [36]. Possible approach is to utilize some of available standards such as Substation Configuration Language (SCL) defined in IEC 61850 [37]. The data analytics results should also be kept in non-proprietary and readable formats to make them easily accessible and re-usable. For the database, it is recommended to use a standard SQL command subset supported by majority of modern database engines [38].

Implementation interfaces — the concept of the interface patterns is not new and comes from object oriented programming and design patterns in software engineering [39]. Four implementation interfaces proposed in Figure 7 define how each of these functionalities needs to behave, what main functions are required to implement, and what formats to use for the results. Interface concept can be seen as a “contract”, which each implementation needs to satisfy. In this framework, the main goal associated with use of these interfaces is to achieve a universal approach and transparency in data integration, configuration handling, use of data analytics, and presentation of the results. The following sections will illustrate the concept using the implementation examples.

4.1. *Transparent data integration*

We will start with the assumptions that the IED data has been communicated and available on accessible file servers. The data collection usually ends up with IED records stored in their native, proprietary, and vendor-specific file formats. An example implementation of the transparent data integration is given in Figure 8. In this example, there are several types and vintages of DFR devices involved coming from vendors such as Ametek, E-Max, and Hathaway (Qualitrol) [40–42]. The example shows interface support for DPRs coming from Schweitzer Laboratories (SEL) and General Electric (GE) [43,44]. Depending on the IED type, model, and vintage, additional IED-specific configuration settings may be needed for a successful file format conversion. For example, some older DFR records do not contain information on the channel assignments, channel names, and scaling. In short,

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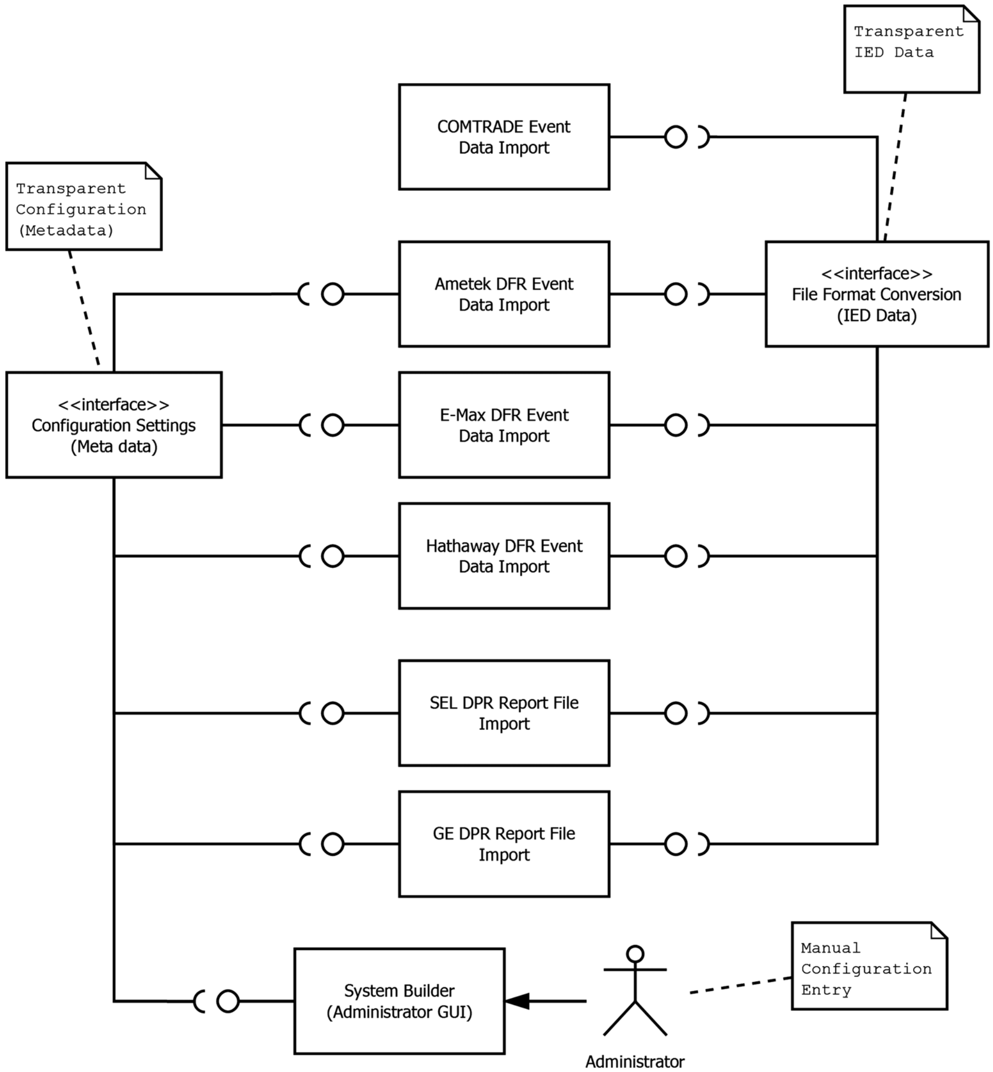

Figure 8. Implementation of the transparent data integration.

the transparent data integration typically involves file format conversion and access to device specific configuration settings. It is important to note that the quality of IED event data can vary from device to device and that not all IED data comes with GPS time stamp. Even if the time stamp is incorrect or missing it is still valuable to carry on with automated fault analysis using single-ended measurements from transmission lines. On a practical note, additional imprecise source of event time information can be obtained from time stamps of event file transfer and data processing, which can later be added to the analytics reports.

Event file import and format conversion — the target is that all the IED data gets automatically converted into a non-proprietary file and made available for further use. Some IEDs do provide tools for exporting data into COMTRADE, or even natively store their records into COMTRADE. Even then the conversion may be needed since COMTRADE standard has various revisions and allows for lots of freedom with respect to which configuration data is provided or omitted. This can result in files that do provide correct syntax, but are not semantically consistent, correct, or complete. Real-life examples include situations where the channel units were not correctly assigned (V or A), channel numbers, phase/circuit designations are missing, etc. Depending on the IED type and model, the event file import function may need to include additional event data that may be available in the IED event files. For example, besides signal waveforms, some IEDs include disturbance start and end times, fault type, and even estimated fault location. This additional information can be integrated and used as an extra crosscheck.

Configuration settings — as mentioned before, the configuration settings are needed for the proper file format conversion as they provide additional information needed to add the semantics to the measurements stored in IED files. As shown in Figure 8, the System Builder tool provides for entering and editing the settings related to the file conversion (channel assignments, scaling, and mapping). It also provides functions for entering system component descriptions needed for the analysis. For a transmission line, it is used to enter line length, impedance, associated buses, transformers, breakers, and protective relays. All this information is made available to the data analytics or its users. One of the biggest challenges is proper configuration change management. All of the configuration settings can and do change over time. Sometimes, the changes are induced by various upgrades in the system and equipment, but also there are changes of the standards and recommendations that are constantly evolving. Systems for automated substation data integration and analytics are heavily dependent on the settings being correct. All the changes in the settings need to be correctly handled using version control as explained in [6].

4.2. Data analytics structure

An example implementation of the data analytics within the provided framework is illustrated in Figure 9. Multiple data analytics functions can be built upon the data integration database and by following the definition of implementation interfaces. First, the data and report access allows transparency in accessing the converted IED data. The data analytics functions do not need to know the details about the IED data source. The same interface is used to feed the analytics reports back to the database. Second, the data analytics implement elements of the configuration access in order to retrieve the meta-data needed to interpret the semantics of the IED records. Finally, the data analytics interface provides for a transparency from the system's point of view. Invoking and controlling the data

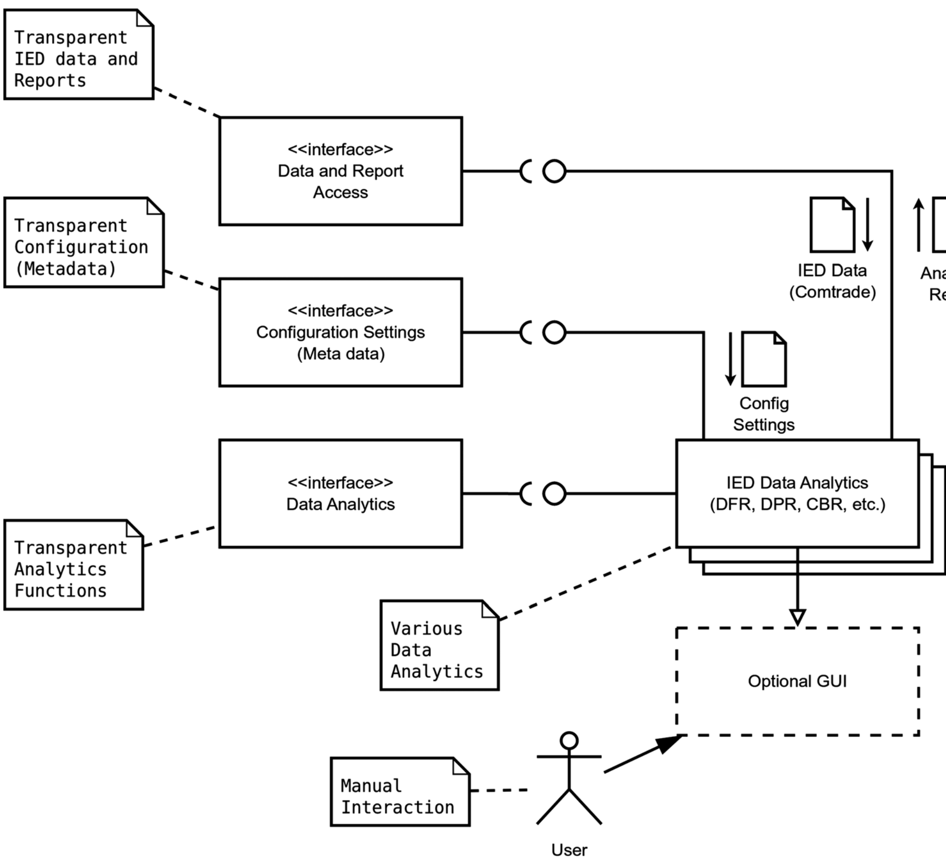

Figure 9. Implementation of the transparent data analytics.

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analytics functions by the system or users should be transparent, using the mechanisms defined in the corresponding interface, regardless of their inner differences and functionalities.

4.3. Universal access to data and analytics results

The same approach is applied to the implementation of universal graphical user interface (GUI) and dissemination of the analytics reports (Figure 10). The data and report access interface is implemented in a web-based and desktop-based GUI. Same GUI options for viewing substation IED waveforms and analytics reports can be used regardless of the data source. The broadcasting module for sending notifications implements the same interface to access the reports. Based on the disturbance type and priority, the notifications are being sent automatically to predefined users groups and users via e-mail, SMS text, fax, or printer.

Desktop-based user interface is more suitable when more intensive interaction with the user is expected. A desktop-based viewer example was given earlier in Figure 1. This waveform and report viewer is implemented in Java using Java Web Start technology [45]. This technology allows the user to load and start the application from the web and the only requirement is that the user's computer is equipped with Java run-time. Once started, the desktop-based viewer loads IED event data and allows the user to inspect the waveforms in great level of details. This rich-client scenario allows for more powerful functions and faster response. The viewer provides channel selection, zoom, overlay, measurement cursors, etc. It is equipped with tools for displaying phasors, harmonics, and fault location. Similarly to the web access, the transparent approach lets the users to use the same tool for inspecting and analyzing substation IED data regardless of the source (DFR, DPR, or other event-triggered IEDs).

Web-based user interface is implemented using the framework that is shown in Figure 11. All the IED event data is organized into a system events table presented to the user. The system events

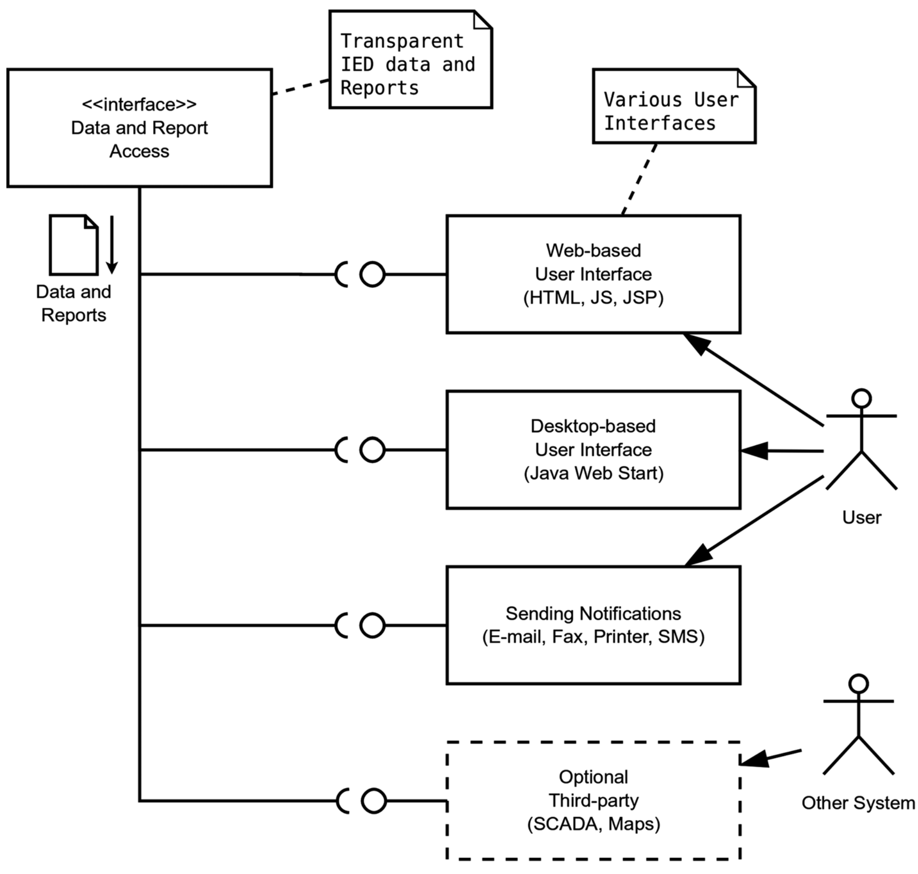

Figure 10. Access to IED event data and analytics reports.

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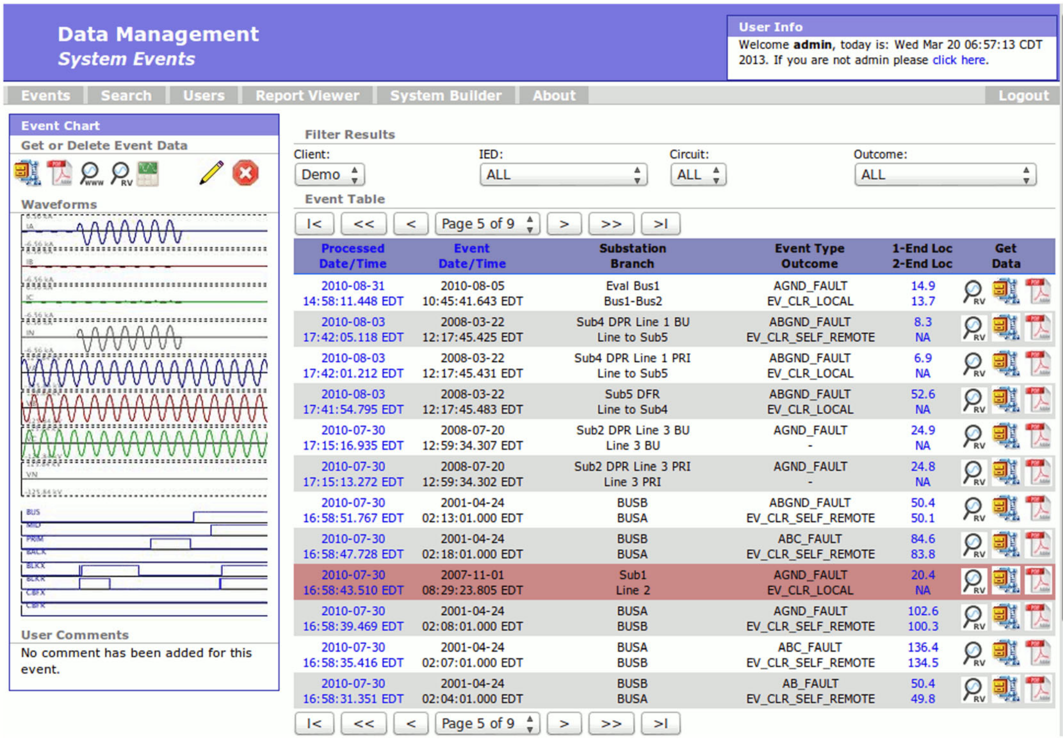

Figure 11. Web-based access to the system events data and analytics reports.

seamlessly integrate event waveforms and analysis results regardless of the substation data source (DPRs or DFRs). The most recent events are displayed at the top. The user can select substation, IEDs, and even circuits of interest in order to filter the list of events. System events table provides brief information on each event such as IED name, circuit, event type, and, if available, the fault location. The waveform view on the left provides a quick look into the analog and digital signals corresponding to the selected event. For example, for a transmission line connected to a breaker-and-a-half bus configuration, those signals include phase currents and voltages, bus and middle breaker status, primary and backup relay trip, etc. The web-based user interface allows for waveform inspection and opening of the analytics reports. The main benefit is that the web access is fully platform independent and can be accessed using only a standard web browser such as Firefox or Internet Explorer. The pages are formatted using standard HTML and CSS [46], which makes the web access suitable for thin-client usage including smart phones and tablets.

Integration with third-party systems — an additional benefit of the framework is that it enables easy interfacing to third-party solutions. The data analytics results could easily be ported to SCADA and PI historian. If done automatically, such solutions enable DFR, DPR, and other IED event records, traditionally considered non-operational data, to be used as operational data. The key knowledge obtained by automated data analytics applied to DFR or DPR data, which is in this case fault type, location, inception/clearance time-stamps, could be transferred to SCADA via CIM and support the operations in their decision-making process [6,47]. Another option to improve the work flow of the engineers is to overlay the fault location information with the satellite maps. It can be done using calculated distance, GPS positions of transmission line ends, and the mapping overlay methods provided in tools such as Google Maps API [6,48].

4.4. *Deployment using open source tools*

The solution for substation data integration and automated analysis can be very successfully deployed using open source software. Figure 12 is illustrating the deployment of the latest generation of the solution using Linux operating system (Ubuntu [49]). The components can be deployed to fit the needs

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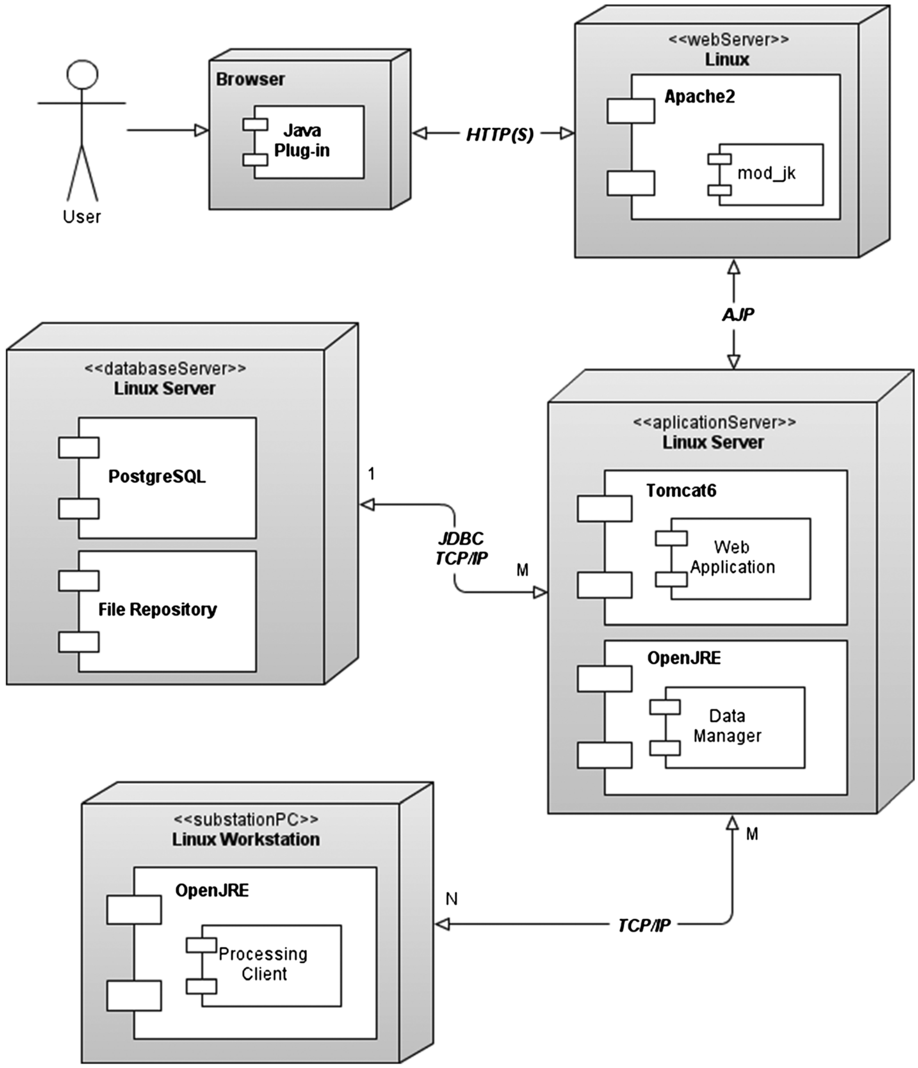

Figure 12. Solution deployment using open source software tools.

of an actual utility and users: substation only installation, centralized, distributed, or regional. The solution is platform independent and can be deployed on other operating systems besides Linux (i.e. Windows or BSD). The solution utilizes Apache HTTP and Tomcat servers, which are secure, scalable, and easy to maintain [50,51]. The data warehouse is implemented using Linux file system and PostgreSQL database [52]. The selected open source deployment tools are widely used and supported by virtualization software [53,54], as well as in the cloud computing environment [55]. The key benefits of the use of open source tools are improved portability, interoperability, scalability, security, and maintainability.

5. VERIFICATION AND TEST RESULTS

The data analytics functions described in this paper have been thoroughly tested and evaluated. It is not always an easy task to provide enough "good" test data obtained from field recordings, especially if the testing requires fault data from both ends of transmission lines. The following sections illustrate in-house testing with simulated fault data and test results based on the field installation that included multiple types of IEDs.

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5.1. In-house testing with simulated faults

The initial evaluation has been done using historical records from different IEDs, DFR, and some DPR files, but in order to provide additional test data, several fault events have been simulated using an ATP transient simulation tool [56]. A section of a real power system has been modeled in ATP. The model consisting of nine buses, ten transmission lines, and nine generators was used to perform in-house testing. This model has been proven using field data and calibrated to match similar real-life faults. Four different types of faults have been simulated: (i) A-G, (ii) AB, (iii) AB-G, and (iv) ABC. Each fault type has been simulated at 50 to 95% in steps of 5%t from the sending end of the line (50 down to 5% as “seen” from the receiving end). The ATP output files have been exported into COMTRADE using custom script. Generated COMTRADE files have been presented to the analytics as IED recordings coming from two adjacent substations. These recordings created by the simulation were processed by the automated fault analysis and for each case single-end fault location was calculated. The two-end fault location algorithm calculation is initiated whenever the data manager recognized availability of the data from remote end, which was achieved by adjusting the time-stamps inside simulated COMTRADE files. The accuracy comparison for these simulated cases is summarized in Table II. In all cases the fault detection and classification correctly detected and classified the fault type.

Table II. In-house test results.

#	Fault type	Number of cases	Single-end error [%]	Two-end error [%]
1	A-G	30	0.61 – 3.75	0.05 – 0.27
2	AB	30	0.59 – 2.57	0.01 – 0.48
3	AB-G	30	0.61 – 2.57	0.05 – 0.21
4	ABC	30	0.42 – 2.57	0.05 – 0.21

Note: error % relative to line length

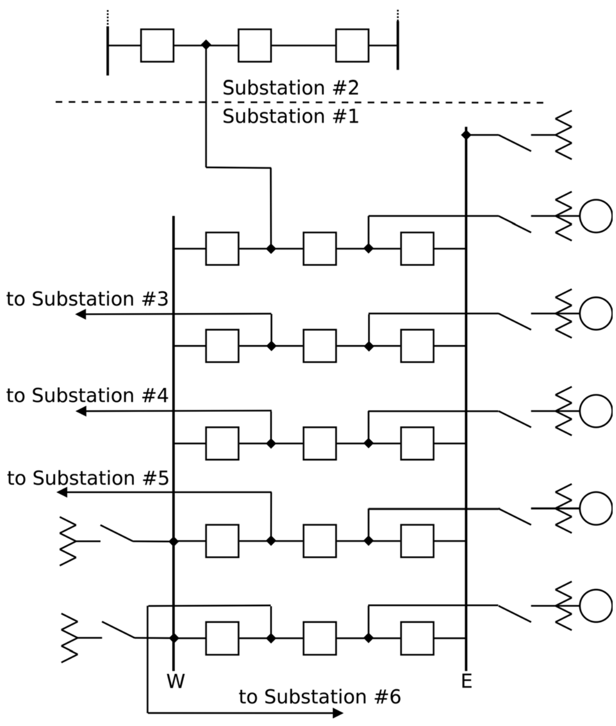

Figure 13. One-line diagram of the field evaluation site.

5.2. Field data evaluation and demonstration

The field data examples discussed in this section are obtained from the two substations shown in Figure 13. The distance between the two substations is around 49 miles. IED data are collected from two substations (#1 and #2): (i) one DFR and seven DPRs; and (ii) one DFR and two DPRs (primary and backup on the line towards substation #1) in substations #1 and #2, respectively.

The data analytics solution was installed on a single server-grade computer at the central office (Figure 14). All of the DFR and DPR data was GPS time-stamped and communicated to the data collection servers. The CBR data was time-stamped using custom network protocol for time synchronization with the communication server. The CBR data was used only for evaluation since not many field-recorded files were available. It is important to note that a different data analytics function was used for each IED data type. However, each analytic function implemented the same interface as proposed by the implementation framework and allowed for seamless integration into the solution.

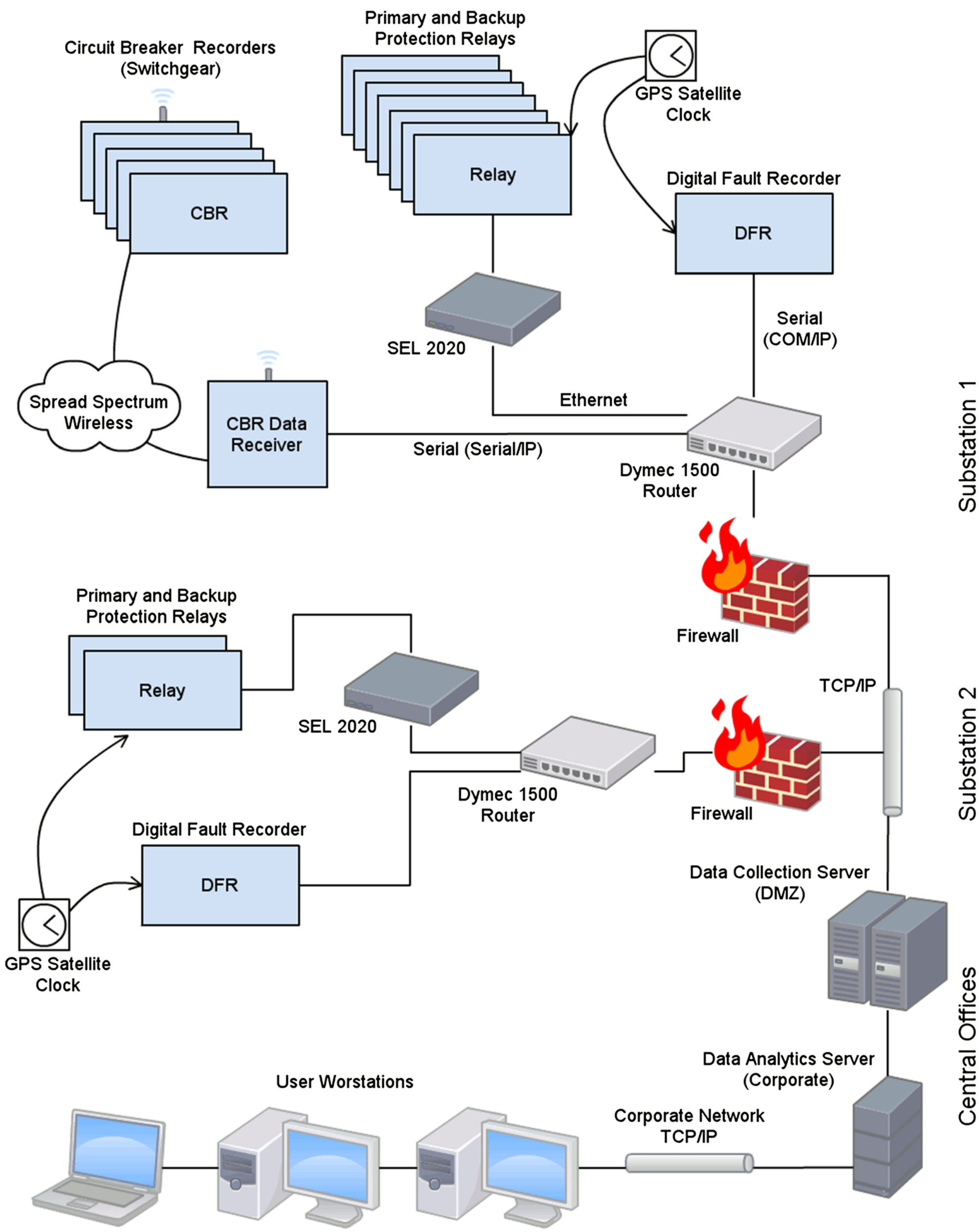

Figure 14. Field evaluation setup architecture and IED connection.

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Several hundreds of field-recorded DFR and DPR event files have been collected and processed by the data analytics setup. Some historical data of the known fault events was processed as well. It was particularly interesting to observe the events for which multiple IED records were available. For these cases, it was possible to compare the results based on the data coming from different DPRs and DFRs. Six historical field events have been selected to illustrate the results that can be obtained with the solution.

Example 1 — this is a case where multiple IED recordings were available for the same fault event. In this case, the actual fault was located on the transmission line between substations #1 and #4 at 23.7 miles from substation #1. The fault event was captured by six IEDs (Table III) including primary and backup distance relays on that line and DFRs in both substations. All the IED data was properly integrated. DPR data is being converted into same version of COMTRADE file format and DPR reports are automatically parsed for fault information. Both relays on the faulted line tripped and calculated fault at around 24.9 miles. DFR data was automatically converted and analyzed by the automated processing function that correctly calculated the actual fault location at 23.7 miles. It is

Table III. Example 1: Field-recorded event data from multiple IEDs.

#	IED/Line	Time stamp	Fault type	Fault location
1	DPR Line Primary Sub #1 to #4	11:59.34.302	A-G	24.85
2	DPR Line Backup Sub #1 to #4	11:59.34.307	A-G	24.93
3	DPR Line Primary Sub #1 to #2	11:59.34.343	A-G	−414.7
4	DPR Line Primary Sub #2 to #1	11:59.34.305	A-G	498.5
5	DFR at line Sub #1 to #4	11:59.34.207	A-G	23.7
6	DFR at line Sub #2 to #1	11:59.34.295	Not a fault	N/A

```
*** Event Summary ***
Trigger Date and Time:          20XX-XX-20 11:59:34.207
Start Date and Time:            20XX-XX-20 11:59:34.132
Disturbance Start, End:         65, 106 [ms]
Duration:                       41 [ms]
Event Description:              AGND_FAULT
Fault Location:                 23.7 [Miles]

Event Outcome:                  EV_CLR_LOCAL
Breaker Operation:    1st,      CB_OK
Breaker Operation:    2nd,      CB_OK
Relay Operation:      PRIM,     RL_NOT_MONITORED
Relay Operation:      BACK,     RL_NOT_MONITORED

*** Analog signal Values ***
Prefault Values:    Fault Values:       Postfault Values:
I0=   0.0118 [kA]   I0=   6.5834 [kA]   I0=   0.0038 [kA]
Ia=   0.5158 [kA]   Ia=   6.6937 [kA]   Ia=   0.0006 [kA]
Ib=   0.5478 [kA]   Ib=   0.5190 [kA]   Ib=   0.0037 [kA]
Ic=   0.5638 [kA]   Ic=   0.6320 [kA]   Ic=   0.0004 [kA]

U0=  19.3244 [kV]   U0=  45.3375 [kV]   U0= 195.1439 [kV]
Ua= 198.0319 [kV]   Ua= 162.1927 [kV]   Ua= 198.0891 [kV]
Ub= 197.5894 [kV]   Ub= 195.6939 [kV]   Ub= 197.3722 [kV]
Uc= 216.1114 [kV]   Uc= 214.2247 [kV]   Uc=   1.8417 [kV]

Uab=343.1335 [kV]   Uab=308.4148 [kV]   Uab=342.9095 [kV]
Ubc=356.7998 [kV]   Ubc=354.6029 [kV]   Ubc=198.2614 [kV]
Uca=359.8151 [kV]   Uca=329.4935 [kV]   Uca=199.0470 [kV]
...
```

Figure 15. Example 1: DFR data analytics report.

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important to note that the data from other relays, although not providing the fault location, can be useful for system protection engineers to get a better assessment of what happened (Table III). The report examples from the DFR and DPR data analytics are given in Figures 15 and 16. The DFR report was created utilizing the data analytics based on the signal waveforms. At later time, a DFR file from the remote end was obtained from the neighboring utility and we ran two-end fault location, which also resulted in a match with the actual fault location.

Example 2 — the actual fault type was B-G on the transmission line between substations #1 and #6 just outside substation #1 (Table IV). The data in the third and fourth rows in Table IV correctly points to the actual fault location, while other two relays on lines towards substations #2 and #4 correctly "saw" the fault behind (inverse fault). All the time stamps and fault type match, which gives additional reassurance to the user of what had happened.

Example 3 — the actual fault was B-G, but beyond the transmission line between substations #1 and #4. Both the relay calculation and DFR analysis calculation "saw" the fault at the same location (Table V). This is an example of what kind of results we can obtain from a substation that is not in direct contact with faulted circuits.

Example 4 — the actual fault was C-G on the transmission line between substations #1 and #3 at around 8 miles from substation #1 (Table VI). Again, there is a good match between the DPR and DFR analysis on that line. The time stamps and fault type match in all available records.

Example 5 — this illustrates DFR analysis results in case where the protection signals were monitored by the DFR. The transmission line is connected in a breaker-and-a-half configuration. The fault was correctly identified as a three phase. Both primary and backup relays tripped and bus

```
*** Relay Event Summary ***
Substation:                 Sub2 DPR Line 3 BU
DPR Native File Name:       Relay BU, XXXX20.EVE
Affected Circuit:           Line 3 BU
Trigger Date and Time:      20XX-XX-20 11:59:34.307
Start Date and Time:        20XX-XX-20 11:59:34.207
Event Description:          AGND_FAULT
Fault Location:             24.93 [Miles]
...
```

Figure 16. Example 1: DPR data analytics report.

Table IV. Example 2: Field-recorded event data from multiple IEDs.

#	IED/Line	Time stamp	Fault type	Fault location
1	DPR Line Primary Sub #1 to #2	07:15:02.825	B-G	−7.49
2	DPR Line Primary Sub #1 to #4	07:15:02.826	B-G	−4.32
3	DPR Line Primary Sub #2 to #1	07:15:02.782	B-G	49.25
4	DFR at line Sub #1 to #6	07:15:02.704	B-G	0.2

Table V. Example 3: Field-recorded event data from multiple IEDs.

#	IED/Line	Time stamp	Fault type	Fault location
1	DPR Line Primary Sub #1 to #4	19:55:44.772	B-G	63.7
2	DPR Line Backup Sub #1 to #3	19:55:44.933	B-G	375.5
3	DFR at line Sub #1 to #4	19:55:44.925	B-G	63.8

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Table VI. Example 4: Field-recorded event data from multiple IEDs.

#	IED/Line	Time stamp	Fault type	Fault location
1	DPR Line Primary Sub #1 to #4	03:05:50.833	C-G	N/A
2	DPR Line Backup Sub #1 to #3	03:05:50.796	C-G	8.06
3	DPR Line Primary Sub #2 to #1	03:05:50.797	C-G	146.3
4	DFR at line Sub #1 to #3	03:05:50.806	C-G	8.4

```
*** Expert System Log ***
The bus breaker opened in 2.92 cycles
The middle breaker opened in 5.74 cycles
Line breaker(s) open after the disturbance!
The event is a non-ground fault!
The event is a three phase fault!
The fault is cleared by the protection at this substation!
Primary relay tripped in 0.83 cycles!
Backup relay tripped in 1.29 cycles!
The bus breaker opened in 2.08 cycles after the primary trip
The bus breaker opened in 1.62 cycles after the backup trip
The middle breaker opened in 4.91 cycles after the primary trip!
The middle breaker is slow!
The middle breaker opened in 4.44 cycles after the backup trip!
The middle breaker is slow!
Primary relay did trip correctly!
Backup relay did trip correctly!
...
```

Figure 17. Example 5: DFR data analytics report — slow breaker operation.

```
*** Expert System Log ***
The bus breaker is closed all the time!
The middle breaker is closed all the time!
The event is a ground fault!
The event is a phase B to ground fault!
There is no clearance!
The bus breaker is OK!
The middle breaker is OK!
Primary relay did not trip because the blocking signal was received!
Backup relay did not trip because the blocking signal was received!
...
```

Figure 18. Example 6: DFR data analysis — blocking signal received.

and middle breaker opened. The analysis correctly recognized that the middle breaker was slow. The excerpt from the DFR data analytics report is given in Figure 17.

Example 6 — this example is for a transmission line in a similar configuration as in previous case. The actual fault event was beyond the transmission line. The analysis correctly evaluated protection operation and recognized that the relays did not trip because the blocking signal was received (Figure 18). The fault was cleared at some other substation.

6. CONCLUSIONS

The goal in this paper is to define implementation framework that combines presented fault analytics methods and techniques into a fully automated analysis solution that can be applied to all transmission line data where IED event recording is possible. The paper presents architecture requirements and describes a system-wide solution that utilizes DFR and DPR data obtained in transmission substations. The following is a list of the key contributions in this paper:

- The paper provides implementation requirements for a fully automated fault data analytics solution, which is applicable to transmission systems and aimed at handling large amounts of substation data.
- The proposed implementation architecture emphasizes universal implementation and more robust computations that can be transparently applicable to variety of event-triggered IEDs.
- By utilizing existing standards, the solution is open for expansion and interfacing to third-party systems such as SCADA and satellite maps.
- The field configuration setup described in the paper illustrates integration of event data coming from various IED types, but also integration of various data analytics functions.
- By efficient use of event records, the solution has the potential to add value to already installed IED devices and infrastructure.
- The solution was successfully implemented and deployed using open source software tools, which enabled easier maintenance and better scalability and interoperability.
- The proposed implementation framework and transparency in the data warehouse allow for future analytics to be added.
- The solution can be combined with efficient event data collection schemes to provide the fault analytics results to the operators within minutes of the fault occurrence, thus bridging the gap between traditionally separated non-operational and operational data.

7. LIST OF SYMBOLS AND ABBREVIATIONS

7.1. *Symbols*

$i(t)$	instantaneous current signal, time domain
I, I_S, I_R	current phasors (complex), sending end, receiving end
U, U_S, U_R	voltage phasors (complex), sending end, receiving end
Z	line impedance
N	number of samples per cycle
f_S	sampling frequency
f_0	system frequency
I_{dist}	current disturbance matrix, contains current amplitudes per cycle per channel
$\boldsymbol{U}_F$, $\boldsymbol{U}_S$, $\boldsymbol{U}_R$	three-phase voltages, sending end, receiving end, fault
$\boldsymbol{I}_S$, $\boldsymbol{I}_R$	three-phase currents, sending end, receiving end
$\boldsymbol{Z}$	impedance matrix

7.2. *Abbreviations*

AC	Alternate Current
ATP	Alternative Transient Program
CBR	Circuit Breaker Recorder
CIM	Common Interface model
COMFEDE	Common Format for Event Data Exchange
COMNAME	Common Format for Naming Time Sequence Data Files
COMTRADE	Common Format for Transient Data Exchange
CT	Current Transformer
VT	Voltage Transformer
DFR	Digital Fault Recorder
DPR	Digital Protective Relay
GPS	Global Positioning System
GUI	Graphical User Interface
IED	Intelligent Electronic Device
MLS	Minimum Least Squares
PQM	Power Quality Meter

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RTU	Remote Terminal Unit
SCADA	Supervisory Control and Data Acquisition
SCL	Substation Configuration Language

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