Benefits of integrating DFR and PQ data with an asset information model that includes mapping to Planning Models, SCADA Historians, GIS databases, and Asset Management Systems

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***Abstract*— This paper describes the benefits of integrating the systems that process event and disturbance data from digital fault recorders, power quality monitors, and relays for automated fault detection, classification, and location determination as well as other types of disturbance analysis. This paper also presents the approach for and the value of creating a limited information model that can be automatically synchronized with utility primary data stores such as planning models and SCADA historian as well as work and asset management systems.**

The focus of this paper is to describe the automation techniques used to manage and process event data and the information integration opportunities that lower cost and improve the quality of event analytics.

Keywords—Data Integration, PQ Data, Disturbance Analysis, automation

I. Introduction

With improvements in substation intelligent electronic devices (IEDs) such as power quality monitors (PQMs), revenue meters, relays, and digital fault recorders (DFRs) and with the increased deployment of these devices driven from both regulatory and business perspectives, many utilities now have a large fleet of devices that can provide disturbance and power quality data. As this fleet of IEDs has grown, there has been a corresponding growth in the utility's dependency on this data for: asset health determination, investigations of system disturbances, reducing restoration time, improving customer satisfaction, monitoring of key business metrics, and for addressing other business needs.

Information integration enables processes to be established to automate configuration of the analytics so that they quickly track changes in physical infrastructure thereby assuring the highest quality of analytic results. The data integration opportunities presented in this paper have been implemented at the Tennessee Valley Authority (TVA) so that better results can be obtained more quickly and at lower cost.

Section II below describes the open-source software suite designed to automatically collect data from IEDs; run automated fault detection, fault classification and fault location analysis; and provide display and reporting tools to allow utilities to better understand events and their causes. Section II also introduces the general architecture of the software suite and describes the opportunity points for system integration.

Section III contains details on the analytic processes for event data. It covers fault detection, fault cause classification, and fault location algorithms. Section III describes the asset model that facilitates integration with utility asset and work management systems, and which allows the system to be more quickly reconfigured to support maintenance outages such as when a breaker is spared out for maintenance. Section IV describes the integration of the software suite using a case study at TVA and introduces the visualization schemes used to provide engineers with the available information. Finally, Section V summarizes and concludes this paper.

II. Overview of the Automated PQ data flow

The functional components of the software suite that automatically process PQ and disturbance data are typically divided into four major groups:

1. Acquire
2. Analyze & Notify
3. Archive
4. Display

Fig.1 shows the data flows among these four functional components which are explained in the sections below. For this paper, a fifth functional component "integration", has been added. Fig.1 highlights some of the major systems among which disturbance analytics can be integrated. The information integration points are introduced in this section and are described in detail in Section IV.

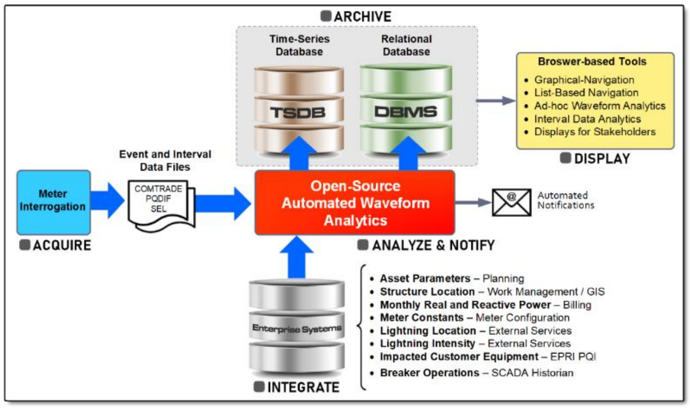

Fig. 1. General Architecture.

A. Acquire

The "acquire" architectural element is responsible for obtaining disturbance event record data from the various IEDs so that a file can be produced in a format that can be easily parsed, such as the IEEE standard formats PQDIF [1] and COMTRADE [2]. Meter vendors often provide meter interrogation software for their devices, some of which can fit within the architecture shown in Fig.1 and some of which are closed systems and cannot. Architecturally, the repository of files that sits between the meter interrogation software and the analytics software is extremely important, serving as a buffer to allow the disturbance analytics to operate asynchronously with disturbance data collection. However, this file repository also provides an important first layer in the chain of event evidence that has been untouched by signal conditioning or other processes. Protecting and saving this data allows downstream systems to be refreshed should new analytic techniques be developed or should issues be discovered in existing techniques.

The open-source software suite described in this paper contains a generalized IED interrogation component that provides scalable (load-balanced) capability to quickly poll and download data from the very largest utility IED fleets through multiple protocols, such as FTP, DNP3 and Modbus. This component also includes custom interfaces for several IED models that provide access to data using only proprietary protocols and formats directly from the meter.

As utility business processes become more dependent on automated, near real-time event analysis, the performance of this interrogation component has the most impact in providing timely notifications to operations, the organization that needs the information first. For example, prior to a transmission operator testing the line following a fault, it would be very valuable to know the probable cause of the fault so as to make more informed decisions. There would be no need to stress transmission assets or risking safety by knowingly reclosing into a permanent fault.

Even if the polling load is distributed among multiple interrogation servers, there may be many hundreds or even thousands of IEDs associated with a single server. To assure that the appropriate devices are polled most quickly, the interrogation component is integrated with the SCADA historian so that if a breaker operation is reported in SCADA, then all IEDs in substations connected to the faulted element are immediately moved to the highest polling priority.

B. Analyze and Notify

The core of the architecture shown in Fig.1 is to analyze and then notify responsible engineers, field technicians, transmission operators, line and electrician crews, account managers and management about the nature of a disturbance.

The analytics can include general algorithms such as those described in more detail in Section III below as well as multiple specialized algorithms that are beyond the scope of this paper. Regardless, the quality of analytics is typically a strong function of the accuracy of asset parameters such as transmission element impedances. Integration with utility planning and asset management systems assures that this asset information is current and matches that used within the enterprise. Integration is also necessary to support probable fault cause classification. For example, determining spatial and temporal correlation with lightning strikes based on data contained in a GIS database can be a strong indicator of lightning as the cause of a fault.

Automated notifications are the sharp point of business value for a disturbance data system. For large utilities, these notifications need to be highly targeted to assure that an important notice for a specific individual does not get lost within a flood of notifications that are not related to their duties. Therefore, notifications must be directed by work function, geographic area, and interest. In a large organization with a fluid work force, maintenance of this notification list for hundreds of individuals can be burdensome and requires automation through techniques such as web-based self-subscription. Integration with the Active Directory systems at the utility improves usability and security for recipients throughout the organization.

C. Archive

To achieve full value from a disturbance data system an open data layer, or archive, is critical. Without it, innovation and process improvement are fully controlled by the vendor that provides the closed system. Due to the fundamental differences in the nature of the data, two types of data bases are shown in Fig.1 for the archive layer. They are:

(1) <u>a relational data base</u> for configuration information, event waveforms and for results of analytics on these waveforms and

(2) <u>a time-series data base</u> for saving interval (min, max, avg, val) data.

A time-series data base (TSDB) is required to address the high-volume of interval data that is produced by PQMs and the ability of TSDBs to quickly ingest interval data regardless of data volume.

D. Display

Multiple open-source tools are available as part of the software suite to facilitate engineering analysis and investigations as well as business reporting. In these tools, there are summary visualizations that allow the user to quickly identify geographic and temporal patterns in the disturbances. In addition, detailed visualizations are available to view the waveforms as well as a to conduct ad-hoc calculations such as

Fast Fourier Transforms (FFT) based on the displayed event waveform.

The specifics as to what data can be integrated within the acquire, analyze & notify, archive, and display functions is described in Section IV below. However, when designing performant and secure points of system integration, how data is integrated can be as important as what data is integrated. The method for integration could be direct interaction with a relational database system. A common practice in large business is the creation of derivative, de-normalized relational systems that mirror data from the primary system, typically called data stores or data warehouses. By duplicating data in a mirrored database, no consuming systems can impact performance or modify data in the source database. More recently, web-based application programming interfaces (web APIs) have emerged as the preferred method for interface where the relational system is completely hidden from the data consumer. Web APIs also have the value of using network ports that are classically open among network security layers within an enterprise thereby significantly simplifying use.

III. Automated Analytics

In order to notify field personnel about the nature of a disturbance, the system must first analyze the data collected from the IEDs in the field to learn the nature of the disturbance. Traditionally this analysis is done by system engineers looking at the voltage and current traces provided by the IEDs. This job begins with a laborious process of seeking out the information from the relevant IEDs, after which data must be organized and interpreted, and computations must be performed to reach a clearer understanding of the actionable information that can be communicated to the field. Automation in this space facilitates more timely notification of relevant information to the appropriate recipients, and also enables system engineers to leverage their expertise toward providing more accurate, detailed, and sophisticated reports.

To support the analysis described in this section, many sources of information must be brought together and made accessible to the automated system in the same way that a system engineer would need to be consulting these systems to analyze the data manually. In some cases, these sources can be queried during analysis such as when searching for occurrences of lightning strikes in the vicinity of a faulted line. In other cases, these sources can be synchronized automatically with the automation asset model described at the end of this section.

A. Signal Processing

Data typically arrives from the IED as a collection of waveforms in the form of point-on-wave voltage and current measurements captured around a moment of interest. These waveforms must first be joined with the automation asset model to determine how this data relates to the system as a whole. This supports downstream analytics by expanding the scope of information beyond that which could be provided by the IED in isolation.

Technical limitations may necessitate a reduction in the number of signals that can be monitored by an individual IED. This has led to cases where point-on-wave measurements must be inferred by calculation using the measured samples from other signals. For example, phase-to-phase voltage samples can be calculated by subtracting phase-to-ground voltage samples, and residual current samples can be calculated by adding together the corresponding phase current samples. The automation asset model provides the necessary information about each measured signal to aid in determining which signals can be combined to produce any missing measurement samples.

Nearly all analytics depend on detection algorithms that make use of a collection of values computed from a sliding window with a one-cycle window size. These values include root-mean-square (RMS), phase shift, and waveshape amplitude. These computed values may also be used in the analysis routines themselves, and engineers may use these values directly to make determinations about the relevance or severity of an event. These values therefore serve as a backbone for the system performing analysis on the collected waveform data. RMS values can be computed directly, whereas the other parameters are determined by computing the coefficients for a best-fit pure sine wave using a fixed frequency and least squares linear regression. System frequency is provided by the automation asset model.

B. Event Detection

Deviations in the calculated RMS values can be used to quickly find areas of the waveform where significant disturbances in the voltage and current signals occurred. This type of test can be used to identify sags, swells, and interruptions in voltage as well as any accompanying spikes in current that may indicate a fault has occurred. This also provides the system with a rough idea of the region within a waveform that the event starts and ends.

For voltage disturbances, thresholds for event detection can be calculated as a percentage of the rated nominal voltage of the system monitored by the IED. As the rated nominal voltage is not necessarily provided by the IED, this calculation is supported by the automation asset model.

Fault detection depends on the identification of significant changes in the RMS current. As current magnitude depends on electricity usage, there is no rated nominal current that analytics can rely on for calculating thresholds. Instead, the RMS values can be compared with each other to determine the region within a waveform that is most likely to contain faulted voltage and current data. As this technique is likely to produce false positives at times when load changes outside of faulted conditions, additional techniques are used to determine the validity of a suspected fault region. With support from the automation asset model and integration with a utility's SCADA system, it becomes possible to determine the actual breaker state even in cases when it cannot be provided by the IED. This provides a particularly robust solution for validation of suspected fault regions.

C. Fault Cause Classification

To determine the cause of a fault, a set of metrics is computed around the faulted region of the waveform. These metrics include raw computations, such as impedance values and FFTs, but can also include information from external systems such as the timing of when lightning strikes occurred around the faulted line. Each classification is assigned a vague probability level based on a set of logic supported by its underlying metric. The classifications are then ranked based on the relative certainty of the probability level which is predetermined based on the accuracy of the logic compared to actual fault cause data. The highest ranked classification assigned with the High probability level is chosen as the representative fault cause. In the absence of a High probability level calculation, the logic selects the highest ranked classification with the Medium probability level instead. Low probability levels are not considered when determining fault cause. Fig.2 provides a graphical representation of how this logic is performed.

Cause	Prob. Levels	High Probability
Break	High, Low	Must have pre-fault current and be a L-G fault. High if pre-fault current goes to zero in faulted phase
Lightning	High, Med, Low	Lightning occurs within 2 ms of fault inception and within half a mile of the line
Tree	High, Med, Low	Must be a L-G fault. Fault resistance adjusted for natural line resistance is >= 20 ohms
Slap/Debris	High, Low	Must be a L-L fault. Ratio of ground current to fault current < 0.1
Arrestor	High, Low	Must have pre-fault current and be a L-G fault. Ratio of third harmonic to first harmonic for pre-fault current > 0.3
Insulator	High, Med, Low	Must be a L-G fault. Fault inception within +/- 15 degrees of voltage peak for faulted phase

Likely cause = only one 'high probability' found → display cause
= multiple 'high probability' found → display cause with most certainty and "?"
= no 'high' and one or more 'medium' found → display cause with most certainty and "??"
ELSE display cause as "unknown"

Fig. 2. Determination of Likely Fault Cause.

D. Single-ended Fault Location

Using standard impedance-based methods, the location of a fault can be determined using information from the IED relative to the location of the monitoring device. This process requires correlation of the faulted voltage and current measurements to calculate impedance as well as knowledge of the length and impedance of the line, which may not be provided by the IED and is instead provided by the automation asset model.

Several methods of fault location exist with various characteristics that make them theoretically more accurate in various circuit configurations. The automated analysis simplifies by performing all fault location algorithms on every fault regardless of the circuit configuration, leaving it to the engineer to determine which of the results are most applicable. Fault location is therefore calculated using the impedance values over the region of the fault to produce a fault distance curve for each fault location algorithm.

For reporting purposes, a representative fault distance must be selected from the wide array of options produced by this approach. To that end, a single cycle is selected as the representative fault cycle for selecting the most accurate fault analysis results. Experience with the analysis suggests that the best cycles are closest to the end of the fault. An alternative approach when the end of the fault cannot be accurately determined is to use the cycle with the largest current. Once the representative cycle has been selected, the median value of the five different algorithms' results is selected as the representative fault location to use for reporting.

E. Double-ended Fault Location

In cases where a line is monitored by IEDs at two separate locations, the data from each device can be joined in order to perform double-ended fault location to produce fault location results that are theoretically more accurate than the traditional single-ended impedance-based algorithms. For this approach, the automation asset model must provide information about which IEDs are monitoring the line and the locations at which they are monitoring. The data from each of these IEDs can then be time-correlated and brought together for the double-ended fault location algorithm. By independently selecting the representative cycle from each location, it is unlikely that the data will have been captured by each IED at the same moment in time. To adjust for this, the A-phase bus voltage at each location is used as a reference angle to rotate the vectors into alignment before running the calculation.

F. Automation Asset Model

Power system configuration is routinely changed to support maintenance activities which can often lead to erroneous results from automated disturbance analytics. To minimize the effort for disturbance analytics to tightly track these maintenance changes, a simplified model is used to describe the power system elements within a substation and to relate these elements to available signals. Among other things, the model can join line segments, buses, breakers, transformers, and capacitor banks. The model includes required attributes for each power system element as well as an extensible set of custom fields that might be needed for future analytics.

By defining the power system elements and the connections among them, it becomes possible to easily change the association of measurements to specific elements as power system configuration changes are made, such as when a breaker is spared out for maintenance. Fig.3 shows a simple substation model with a bus and two connected line segments each with an interposing breaker. Voltage measurements are tied to the bus, and current measurements are tied to each corresponding breaker. The bus is connected to each breaker, and each breaker is connected to the corresponding line. By using the automation asset model, the disturbance analysis engine understands that the voltage from the bus and the current from the corresponding breaker applies to each respective line regardless of how the substation is reconfigured for maintenance activities.

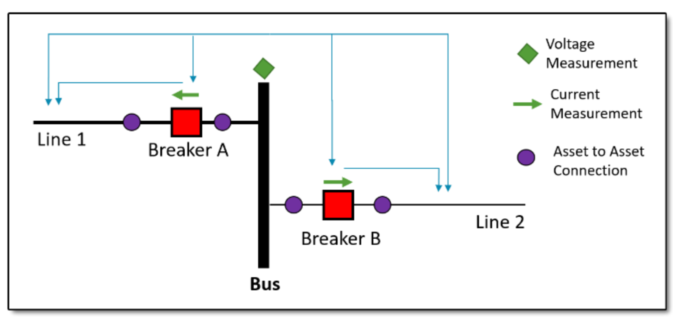

Fig. 3. The simplified Asset Model.

This model approach to mapping IED measurements also improves analytic reliability since secondary and tertiary measurements can be defined for use when the primary measurement is unavailable. This process can be done manually or automatically depending on the situation.

TABLE I
SUMMARY OF TVA DATA INTEGRATION SOURCES

Data Needed	From	Primary PQDM system	Use Level
Asset Parameter	Planning Model DB	Config Tool	Config – e.g. daily refresh
Structure Locations	Asset Management	Analysis Engine	Each time a fault waveform is processed
Monthly P & Q	Billing	Reporting	Monthly
Meter Constants	Meter Change Management	Reporting	Monthly
Lightning location	GIS	Analysis Engine	Each time a fault waveform is processed
Lightning Counts	GIS	Visualization	On demand by the user
Impacted Equipment	Industry Impact	Analysis Engine	Each time an applicable disturbance waveform is processed
Breaker Operations	SCADA	Analysis Engine	Each time a fault waveform is processed

In addition, the model allows utility customers to be associated with a power system element, such as with a bus. This significantly simplifies the process of assuring that the impacts of power quality events can be quickly determined, and that internal notifications can be effectively routed within the enterprise, such as to account managers for key customers.

IV. INFORMATION INTEGRATION CASE STUDY - TVA

Various types of analysis require information that cannot be provided by the IED. This can happen when technical limitations, the scale of the monitoring system, and restrictions around configuration change management drive the burden of fleet-wide configuration changes too high. Traditionally, the system engineer performing the analysis is responsible for gathering the necessary information at the time the analysis is performed. For the automated analysis system, the information can instead be provided to analytics by system engineers maintaining the automation asset model.

System engineers obtain much of this information from external data systems that can be integrated with the suite performing automated analysis. For this type of information, integration reduces the burden on the system engineer and mitigates errors in the process of maintaining the model to track changes to the power system. System integration also provides opportunities to gain access to information that cannot be provided otherwise, such as real-time information from a lightning database or a SCADA historian which the system engineer would not have access to until moments before the engine begins its analysis.

TVA has implemented a number of integrations to improve analysis results. Table 1 below shows the external systems queried and a general description of the data obtained from each.

The following subsections provide more details about some of the major integrations and their benefits to TVA processes. In addition to these, there are a number of opportunities to integrate with other external data systems to be explored in the future, such as meter change management systems, outage planning systems, asset performance systems, and area of vulnerability studies.

A. Planning Model Database

Fault location analysis requires line impedance and line length information to produce fault distance from the IED's voltage and current measurements. TVA's system engineers use a system planning model to obtain this information when updating the automation asset model to support fault location analysis. The planning model database includes information about changes to line configuration and dates on which those changes will be made. Furthermore, the database includes models for impedances and lengths for individual segments that make up a line, thereby providing much more granular information than would be normally required by the automation asset model. This granularity simultaneously provides opportunities for tuning the automated fault location analysis by using the more granular information as well as increasing the burden of configuration for system engineers when updating the automation asset model.

To reduce the burden on system engineers and reduce the possibility for human error in the process, an automated integration layer performs the synchronization between the planning model database and the automation asset model. For this approach, system engineers need only maintain the unique identifier for the lines defined in the automation asset model. The integration layer is given read-only access to a read-only data warehouse to retrieve the information on demand. System engineers can use the integration tool to load data from the planning model database, review configuration changes, and apply them to the automation asset model.

B. Asset Management System

Once the fault distance from the IED is obtained by the analysis, this information can be used to determine the actual location of the fault. At TVA, the asset management system contains information about structures and span lengths across the length of TVA's power lines. A web service uses the information in the asset management system and the fault distance computed by the automated analysis to provide the list of structures nearest the fault as well as their geographic coordinates, which can then be relayed to the appropriate line crews to locate and resolve the cause of the fault more rapidly.

C. SCADA

Because faults often have a large impact on the system, it is common for the automated analysis to receive data from IEDs monitoring lines where the fault did not occur. The fault location analysis often identifies the signature of the current trace as an indication that a fault occurred on that line. Furthermore, in some cases, there is not enough load on the line to determine based on the IED's current measurements whether the breaker operated to clear the fault. This only describes a few of the many conditions that may cause the fault analysis to produce false positive results.

TVA's SCADA historian captures information about the state of the breakers across the system. By adding historian tag identifiers to the automation asset model, associated with the faulted line, it becomes possible to validate the fault analysis results by querying the SCADA historian whenever the analysis detects faulted conditions. This proves to be a highly accurate method for filtering false positive results without the possibility of introducing additional analysis that may produce false negative results instead. Furthermore, by associating historian tags with the breaker in the automation asset model, it also becomes possible to react to system changes automatically when a breaker must be spared out for maintenance.

D. GIS

TVA subscribes to two separate lightning data providers. Data from these providers is consumed by GIS, providing the organization with access to information about lightning strikes within specific geographical regions. When a fault is detected by the fault location analysis, the automated system can use the line identifier from the automation asset model to query GIS for the geographic region representing a half-mile buffer around a faulted line. This region can then be used to query GIS again to find all the lightning strikes in that region within two seconds of the time when the fault occurred. This information is used by the analysis to determine and report the likely fault cause. Detailed information about the relevant lightning strikes, such as peak current magnitude and confidence ellipse, can also be provided to the system engineer.

V. Summary of Automation and Integration Benefits

Automation of routine event and disturbance analysis can produce results more quickly and accurately than traditional processes, providing the organization with more timely information to enable process improvement. Analysis can be performed more easily over a wide area at a lower total cost, and system engineers have access to more tools to focus on bringing more value to the utility. Integration further reduces the burden on system engineers and adds value to analytics by providing information that cannot be provided by the IED in isolation. Furthermore, integration efforts create opportunities for sharing data within the organization, but also externally with its partners. To tackle the challenges that large utilities face as the infrastructure for the monitoring of power quality data grows, automation and integration are powerful tools for managing a large fleet of IEDs and maximizing the value of power quality data.

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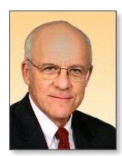

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