Application of DFA Technology for Improved Reliability and Operations

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***Abstract* -- DFA Technology, developed by Texas A&M Engineering in collaboration with EPRI and the utility industry, provides operational visibility and awareness of distribution circuit events, based upon real-time, autonomous monitoring of substation-based CTs and PTs. DFA monitoring devices monitor current and voltage waveforms continuously, detect anomalies, infer circuit events that likely caused those anomalies, and report conditions such as faults and incipient failures via web interface. DFA does not require communications to reclosers, capacitor banks, AMI systems, or other devices downstream of the substation. Examples of detectable conditions include fault-induced conductor slap, pre-failure clamps and switches, problems with unmonitored capacitors, problems with unmonitored reclosers, and recurrent faults resulting from conditions such as cracked bushings. DFA technology provides advance notice of some faults and also helps diagnose vague symptoms and complaints.**

Texas A&M Engineering manages an ongoing DFA field demonstration that involves more than sixty distribution circuits at eight Texas-based utility companies, six of which are rural electric cooperatives. Pedernales Electric Cooperative is one of those participants and, based on experiences gained during the demonstration project, plans to fit most of their 200 distribution circuits with DFA in the next three years.

***Index Terms*—Fault detection, fault location, distribution reliability, power distribution lines, power distribution faults, apparatus failures, incipient faults, smart grids.**

I. Introduction

Electric power distribution circuits have complex topologies, with thousands of interconnected components spanning large geographic areas. Many of those components have lifetimes spanning decades, and comprehensive, frequent inspection of all components would be expensive and yield minimal benefit.

System operators have limited information regarding circuit events and conditions. As long as customers have service and have not notified the utility of a loss of service or other problem, the system is operated under the presumption that all is well. This is not intended as a criticism but rather as a statement of the reality that operators lack tools that give them awareness of problems until a major event occurs. Even when operators receive notice of a problem, that notice often consists of an indication of the operation of a substation circuit breaker or a vague customer complaint, such as “lights out” or “blinking lights.” Crews then begin the process of determining the cause and location of the problem, effecting repairs, and restoring service. Over the past decade, technologies such as AMI (advanced metering infrastructure), distribution automation, and self-healing circuit technologies have enabled improved response to outages, but those technologies remain reactive, coming into play only when an outage has occurred.

II. Circuit Events Represented by Waveforms

Current and voltage waveforms on distribution circuits contain information representative of circuit events. An event on a circuit affects the circuit’s currents and voltages. Some events have minor effects; others have more substantial effects. For example a bolted fault event and a capacitor switching event both affect circuit currents and voltages, but the fault to a substantially greater extent than the capacitor.

Different types of circuit events exhibit different electrical characteristics. If a specific type of event’s characteristics event were 1) well understood and 2) distinct from characteristics of other types of events, then a person knowing these characteristics could analyze electrical measurements, of suitable fidelity, and thereby infer certain circuit events. For example, the electrical characteristics of Fig. 1, which represent a capacitor switching event, are quite distinct from those of Fig. 2, which represent a motor start event. These two examples are readily recognizable from data of RMS granularity (current, voltage, Watts, vars), although other events require current and voltage waveforms having higher fidelity and “sinewave” granularity, inclusive of fundamental-frequency components, harmonics, and transients.

The aforementioned examples were selected to illustrate the principle of using electrical measurements to infer circuit events, using events likely familiar to the reader and having well understood electrical characteristics, rather than as events likely to hold interest during normal circuit operation.

The point of this section is that electrical signals, measurable from conventional, substation-based current and potential transformers (CTs and PTs), are rich in information regarding circuit events and conditions, and that these signals can be used to infer circuit events.

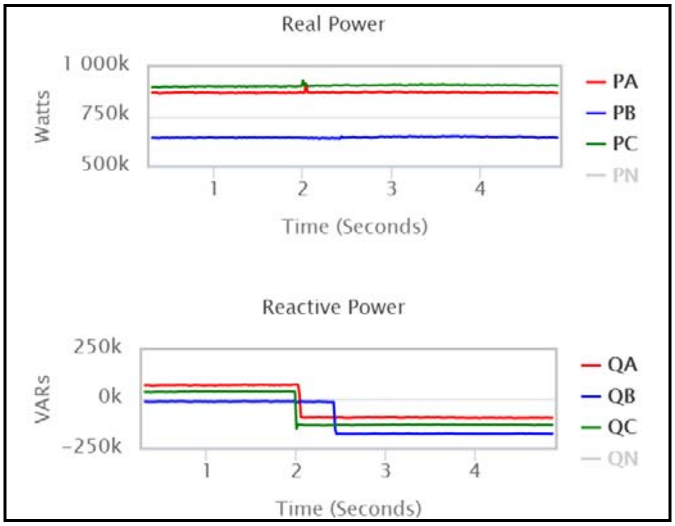

Fig. 1. Real and reactive power as three-phase capacitor bank switches on

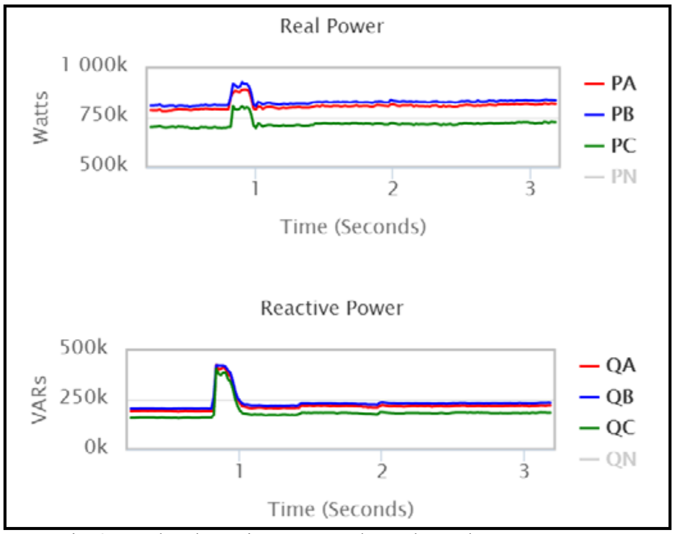

Fig. 2. Real and reactive power as large three-phase motor starts

III. DFA Technology

Texas A&M Engineering, in collaboration with the Electric Power Research Institute, has developed technology known as Distribution Fault Anticipation, or DFA, which provides awareness or visibility of circuit events based on analysis of electrical waveforms [1-3]. The DFA system continuously monitors current and voltage waveforms, detects anomalies, and infers circuit events by applying specialized, proprietary software to the waveform data. DFA Devices, installed in substations and applied on a one-per-circuit basis, perform the above functions and send the resulting reports to a central Master Station computer, via encrypted communications network. Utility personnel access those reports via password-protected login to the Master Station. Each DFA Device monitors a single circuit.

IV. DFA Waveform Data Recording

DFA Devices continuously digitize current and voltage waveforms from current and potential transformers (5-amp circuit CTs and 120-volt bus PTs). Upon detection of anomalies, they record snapshots of the waveforms.

Certain types of events of interest cause only minor variations in current and voltage waveforms, well below thresholds that relays, power quality meters, or other conventional devices typically would be configured to detect. To detect such events, DFA technology intentionally triggers on, records, and analyzes small-magnitude anomalies as well as larger ones. DFA Devices consequently record more data than power quality meters, but they automatically apply the specialized DFA analysis software, thereby relieving personnel of the requirement to analyze much of the data. The intent of DFA technology is to provide actionable information, where possible, not just raw data.

DFA snapshots also are longer than would be typical for other technologies. More than a decade of DFA field research has shown that proper interpretation of certain events of interest requires analysis of these relatively longer recordings. Each DFA Device has configurable parameters that affect the minimum length of each recording and typically is configured to record two seconds of data prior to an anomaly and eight seconds after the anomaly. If anomalies continue after a recording has begun, software logic extends the duration. Some DFA recordings have durations of up to sixty seconds, at full fidelity and sampling rate.

Fig. 3 shows current and voltage waveforms a DFA Device recorded during a fault that resulted in a single trip/close of a hydraulic recloser. The recording has a duration of twelve seconds. Fig. 4 shows data from the same recording but zoomed in to show more detail in the period immediately surrounding the 34.5-cycle fault.

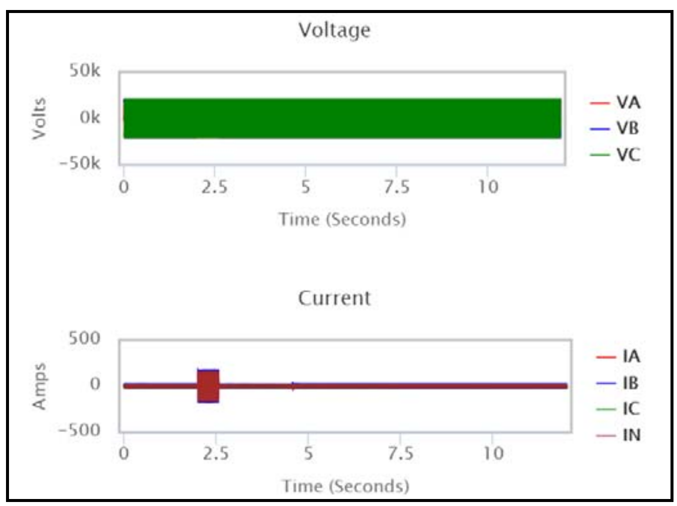

Fig. 3. Twelve-second recording during fault that caused single trip/close of hydraulic recloser

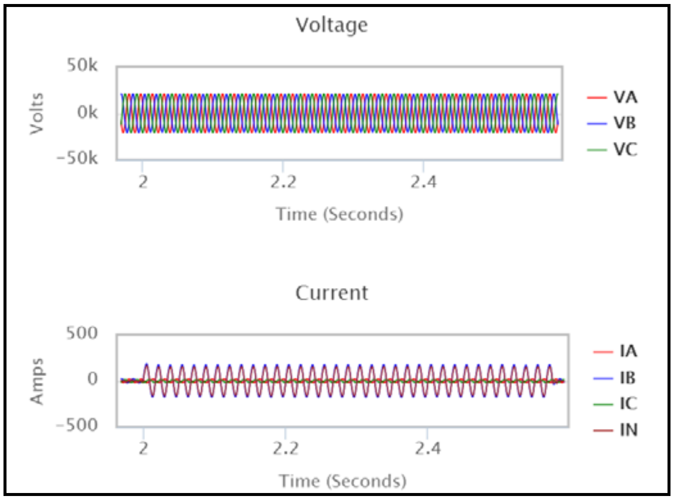

Fig. 4. Zoomed view of data of Fig. 3, centered on 34.5-cycle fault

V. Multi-Cooperative DFA Demonstration

Long circuits typical of rural electric cooperatives have many exposure miles and many connected apparatus, often covering large areas. Consequently they tend to experience problems more frequently than shorter circuits do. This makes them good candidates for technologies such as DFA, which use sensing at a single location, per circuit, to detect events along the length of the circuit.

Eight utility companies in the state of Texas, six of them cooperatives, are participating in a field demonstration of DFA technology. Each participating utility has installed substation-based DFA Devices on multiple circuits. At the writing of this paper, approximately 60 distribution circuits have been instrumented with DFA for nominally one year. Pedernales Electric Cooperative, which is the largest cooperative in the United States and the employer of one of the authors of this paper, has DFA on ten of its circuits.

Texas A&M conducts meetings of project participants approximately twice per year, to facilitate interaction and sharing of information between the participating companies.

VI. Synergistic Use of Technologies

Neither DFA nor any other technology meets all needs or solves all problems. Engineers and operators at some utilities have experimented with how to use DFA and other technologies with each other to maximize benefit. Through trial and error they have developed methods to discover and remediate problems, sometimes using multiple tools synergistically. The case studies in this section include examples of such uses. Each utility company has unique constraints and sets of tools and therefore may need to develop its own methods.

VII. Illustrative Case Studies

Review of selected cases illustrates how participants have begun to use DFA technology to learn of, investigate, and solve outages and other circuit issues. The following cases represent a small fraction of the number of issues that participants have addressed over the first year of the demonstration project and have been selected to demonstrate specific concepts and capabilities. The cases represent events on the systems of multiple participants, not just Pedernales.

A. *Case 1: Reporting faults and recloser operations*

When DFA software detects a fault, it analyzes the associated current and voltage waveforms to characterize the fault itself and the response of the protection system. DFA software identifies and reports the faulted phase(s), fault magnitude, and fault duration. If it detects a trip or trip/close, it reports timing and other information about the sequence. In cases where there are multiple trip/close operations, it identifies the full sequence of events.

Fig. 5 illustrates RMS currents and voltages that a DFA Device recorded during a fault that caused a single trip/close operation of a hydraulic recloser. Fig. 6 illustrates the corresponding sequence of events (SOE) that DFA software generated for that event. Presented in shorthand fashion, the SOE indicates a phase-B fault that drew 113 amps, lasted 34.5 cycles, and tripped a single-phase recloser, which interrupted 16% of phase-B load, stayed open for 2.0 seconds, and reclosed successfully. The 34.5-cycle fault is obvious in the graph of RMS current. The reclose transient is evidenced by the small "bump" in RMS current (and barely perceptible dip in RMS voltage) at t=4.6 seconds.

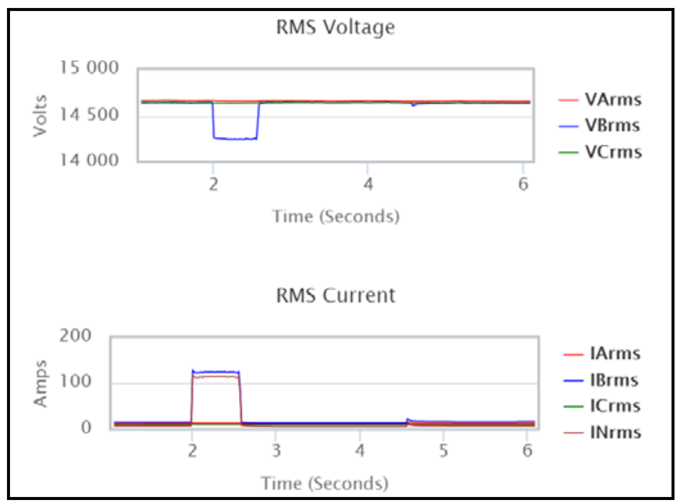

Fig. 5. RMS currents and voltages related to a trip/close event (Note: This is the RMS representation of the event of Fig. 3)

Single-phase reclose	F-(34.5c,113A,BN)-T-(3,16,0)%-2.0s-C

Fig. 6. Sequence of events inferred from waveforms of Fig. 5

The DFA Device transmits the SOE to the Master Station for access by utility personnel. Analysis and communications processes occur autonomously, without action by personnel. The information of Fig. 6 generally can be available to the system operator within two to four minutes of the event, although it may be delayed for various reasons, such as a delay in the communications channel between the DFA Device and the DFA Master Station. In some cases, the system operator receives some other indication of a fault (e.g., a monitored recloser reporting that it operated or that it saw a fault current but did not operate, to coordinate with downstream protection). Other times, the only notice is from the DFA system.

The fault of Fig. 6 drew only 113 amps, indicating it likely was far out on the circuit. In many such cases, particularly where fault currents are on the order of a few hundred amperes, the DFA notice may be the only notice the system operator receives prior to a lights-out call from a customer.

B. Detection and location of outages

Sometimes a fuse operates at the same time a recloser trips. The recloser may close back in, but the blown fuse results in an outage. Project experience has documented this a substantial number of times.

System operators have begun investigating DFA-reported single trip/close faults that occur during fair weather, and they have had good results detecting and locating outages and restoring service, sometimes without ever receiving a customer call.

Fig. 7 illustrates the circuit model and fault location information associated with one such event. A system operator noted that DFA had reported this fault and single trip/close operation. From the DFA report, the operator noted the faulted phase and fault current and entered this information into the utility's existing electronic circuit model. This process predicted the location shown in Fig. 7. The operator then pinged nearby meters and found one meter without power, at the location identified in the figure. Based on this, the operator dispatched a line crew, which found and replaced a blown line fuse that provided service to two wells that provide water for cattle at an unmanned location. All of this occurred without a customer call. Because the nature of the load, the wells otherwise would have been out of power for an arbitrarily long period of time, which could have resulted in the cattle running out of water.

The same utility company reports another event for which operators received multiple calls reporting momentary interruptions but had no other information. Based on the locations of the customers who reported the event, operators inferred which recloser had operated and dispatched a crew to patrol the area downstream. The recloser was unmonitored. The line downstream of it served 157 meters and was rather lengthy, as shown in Fig. 8. Consequently operators dispatched two crews to patrol. Shortly thereafter, operators received a fault current estimate from the DFA system, along with an indication that the probable cause was a failed arrester. The operator entered the fault current into the circuit model and obtained a more specific location to target the search. The operator redirected one of the crews to that location, with instruction that the most likely cause was a failed arrester. The crew found a failed arrester (Fig. 9) and blown fuse near the predicted location.

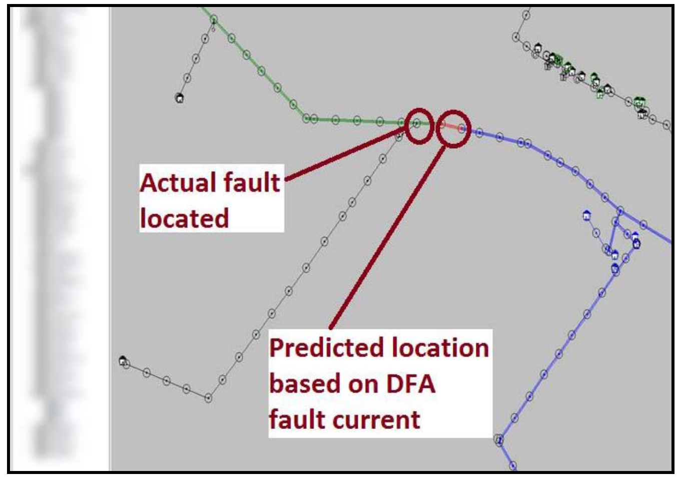

Fig. 7. Location of fair-weather fault that blew fuse to two wells

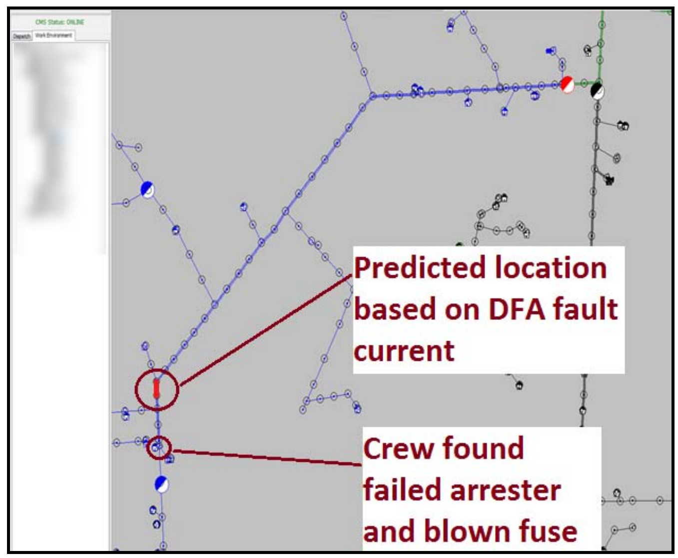

Fig. 8. Location of fair-weather fault that "blinked" 157 customers

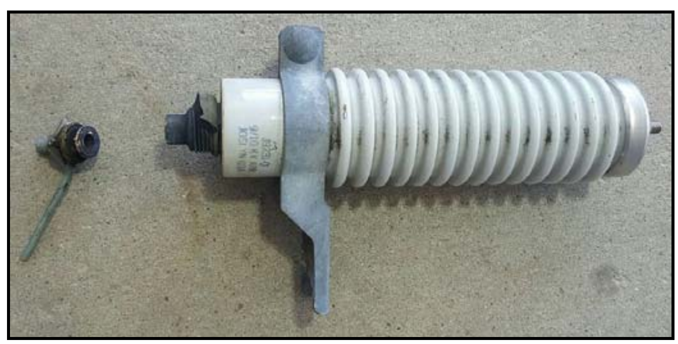

Fig. 9. Failed arrester associated with fault of Fig. 8

C. Detection of intermittent tree contact (no outage or customer complaint)

A variety of circuit conditions can cause multiple episodes of faults, trips, and recloses. Individual episodes may be separated in time by minutes, hours, or days. For example, a cracked bushing on the primary of a customer service transformer may flash over each time its surface gets wet. A single fault/trip/close sequence often dries the bushing's surface and allows restoration of normal operation, until the surface gets wet again in the future. Conditions such as intermittent tree contact can cause similar series of recurrent fault events. Such a condition results in near-identical repetitions of the same fault, at the same location, with the same response of the protection system. DFA field experiences has shown that customers often do not report momentary operations, even when they experience multiple momentary operations over the course of multiple days, and consequently utility company personnel remain unaware that the circuit has a problem.

As the preceding case studies discuss, when a fault occurs, DFA software analyzes, characterizes, and reports that event. A second layer of the DFA software then looks for repeated events. Each DFA Device does this by examining the database of faults it maintains for its circuit. If it finds multiple, recent faults with similar characteristics, it "clusters" these events together to produce a "recurrent fault" report. Utility personnel then can analyze the characteristics of the individual events within the cluster to determine whether they believe those events truly are the same fault and, where appropriate, initiate further action. They may use other tools in this process.

In the subject case, DFA reported that it had found three similar faults occurring during a nine-hour period. The three faults were on the same phase and had the same fault currents and durations (three faults in order: 295 amps for ten cycles; 303 amps for nine cycles; 301 amps for 9.5 cycles). It also reported similar durations for the momentary interruptions (1.4s; 1.4s; 1.5s) and similar amounts of load momentarily interrupted (15%; 17%; 14%).

The utility company received no conventional reports of outages or other complaints. The DFA report was the only notice of the recurrent fault.

The subject circuit is a 12.5 kV circuit of conventional overhead construction, having 153 miles of primary conductor and serving 1 008 customers. The map of Fig. 10 shows the subject circuit, highlighted in orange.

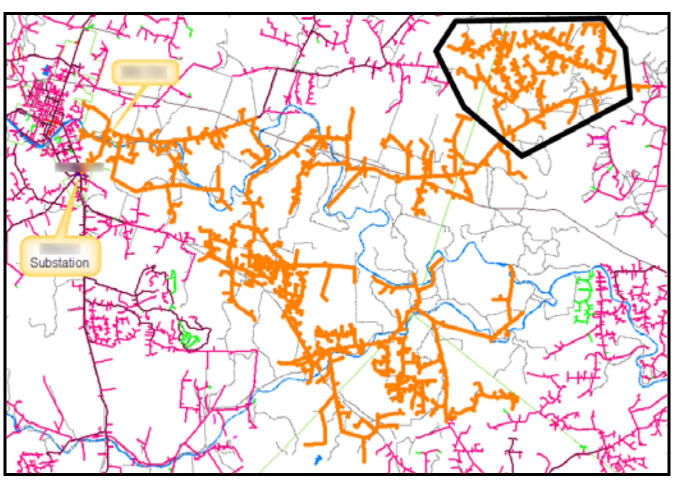

Fig. 10. Map of circuit with recurrent fault (circuit in orange)

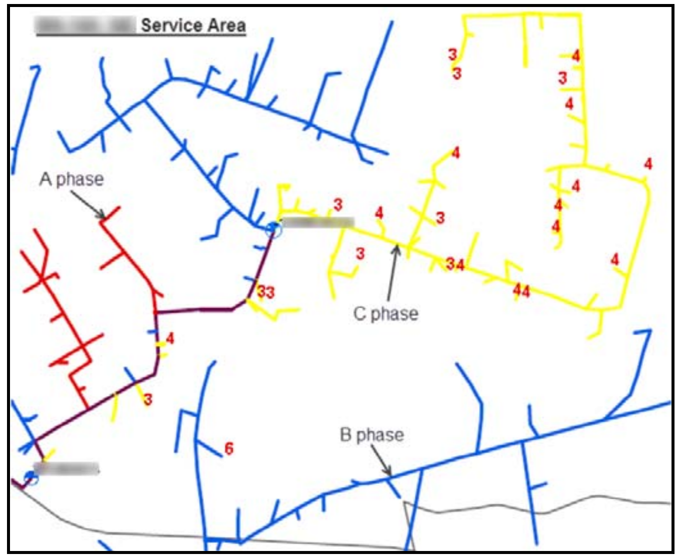

Fig. 11. "Blink" counts of meters in area predicted by DFA

The utility initiated an investigation in response to the DFA recurrent fault report. By using DFA-reported information in conjunction with their circuit model, they identified the outlined area, near the top right corner of the map, as being consistent with all DFA-reported information (faulted phase; fault current magnitude; fault duration; amount of load interrupted; duration of momentary interruption). The utility then used its AMI (advanced metering infrastructure) system to determine "blink counts" for all meters within the outlined area, for the relevant time period. Fig. 11 shows the blink counts in that area and indicates a relatively small region that had experienced the multiple "blinks" in the time period of interest. A targeted search in that area located a branch on the line. The problem was detected, located, and remedied without any customers experiencing an outage or reporting a problem.

The most fundamental factor enabling correction of this problem was learning that it existed. Absent the DFA notification, the utility was unaware of the problem and therefore unable to address it. Once the condition was known, the multiple DFA-reported parameters about the faults and the response of the protection system were important to directing the efficient location of the problem.

D. Detection and location of failed arrester

This case involved a fault and a single, successful trip/close operation of a substation circuit breaker, during a storm. Both DFA and conventional SCADA reported the event. Singular events such as this one are common during storms and generally do not require follow-up investigation.

In the subject case, however, high-fidelity DFA waveform recordings suggested catastrophic failure of a lightning arrester as the likely cause of the fault. Based on the DFA-based indication of a failed arrester, the utility company initiated a search.

The subject circuit has 120 miles of overhead exposure operating at 12.5 kV. The DFA report provided an estimated fault current, which the utility entered into its circuit model, thereby obtaining information to target the search. In addition, it was known from the DFA report and from conventional SCADA that it was the substation circuit breaker, not downstream protection, that trip/closed, so the search area was limited to line segments upstream of the next level of protection downstream. Fig. 12 shows the targeted search region. The utility dispatched a line crew to search that region, with specific instruction to look for a failed arrester. Based on that information, the crew found a blown arrester at the location circled in the figure.

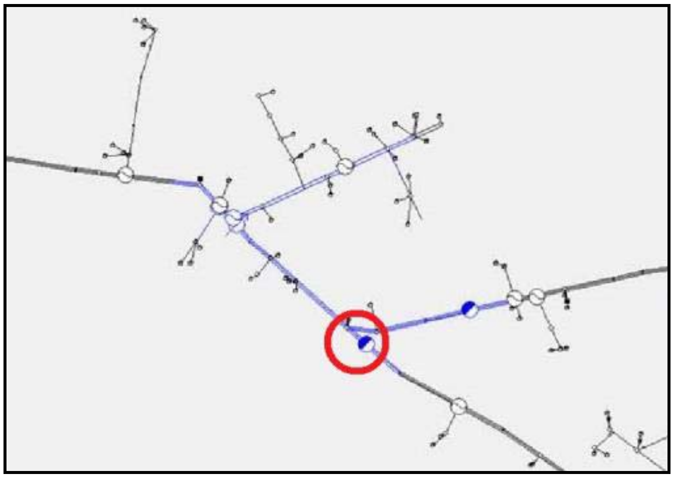

Fig. 12. Search region (blue lines) and location of failed arrester (red circle)

In this case, identification of the failed arrester was based on manual analysis of DFA-recorded waveforms, not an automatic identification by software. The same was true for the previously cited case study involving an arrester. Subsequent to these events, Texas A&M has implemented an experimental algorithm to automate the identification of arrester failures. That experimental algorithm had begun early testing at the writing of this paper.

E. *Incipient failure of hotline clamp*

DFA research discovered unique electrical signatures resulting from the development of "hot spots" in series connections, such as switches and hotline clamps. These hot spots may flare up intermittently. When they do, they tend to cause minimal changes in line current and almost no perceptible change in voltage. An interesting, observed characteristic about the behavior of series connections experiencing this condition is that they may "flare up" for minutes or even hours at a time, but then enter quiescent periods lasting hours to days, during which they exhibit minimal detectable activity. As a consequence of series arcing, customers may experience fluctuations in voltage that cause their lights to flicker. Such conditions can prove difficult to diagnose, because of the intermittency. Consequently the customer's voltage may be solid at the time a line crew visits in response to a complaint by the customer. DFA research also has documented multiple instances in which the electrical variations caused by a failing clamp can blow small fuses. Again, a line crew responding to a fuse blown by such a condition may have no indication of the cause and may be able to replace the fuse and successfully restore service. In such a case, they have treated the symptom but not identified the actual problem.

Although such conditions cause minimal change in the amplitude of line current, the signature has unique features at a detailed level. DFA software often can identify series arcing signatures. DFA software is biased to minimize false alarms, so it waits until it has detected multiple episodes of the series arcing signature, in a relatively period of time, before reporting the problem to operators. This approach generally has been found to be a good compromise, because series arcing episodes tend to repeat numerous times. DFA research has documented multiple cases of series arcing failures causing dozens to hundreds of episodes, spread across multiple days or even multiple weeks.

In the subject case, DFA reported series arcing multiple times on a Saturday, Monday, and Wednesday, and then almost continuously for several hours on Friday. Almost all recorded activity occurred during mid-day hours, although the reason for this is unknown.

Fig. 13 shows a graph of 20 seconds of RMS data during one flare-up. The main point of the graph is that the series arcing event causes minimal change in line currents and voltage, but DFA software is able to recognize this distinctly as series arcing.

The utility company received no customer complaints that week. The following Monday a customer reported that his lights had been flickering all weekend. It is speculated that affected customers may have been away from home during the weekday, daytime hours when most of the flare-ups occurred, but then at home on the weekend.

Upon receiving the complaint from the customer, the utility company performed a thermal scan and found that the clamp serving this customer and seven others had significantly elevated temperature. Fig. 14 shows an image from the thermal scan. The hotline clamp and stirrup both had significant evidence of series arcing and melting of metal, as shown in Fig. 15.

VIII. FUTURE DEPLOYMENT PLANS FOR PEDERNALES

Pedernales has roughly 200 distribution circuits. Based on events that they and other project participants have experienced to date, Pedernales has decided to deploy DFA across their system. They anticipate full deployment to take approximately three years. Pedernales also has begun to investigate how to integrate DFA information with other tools available to its system operators and engineers.

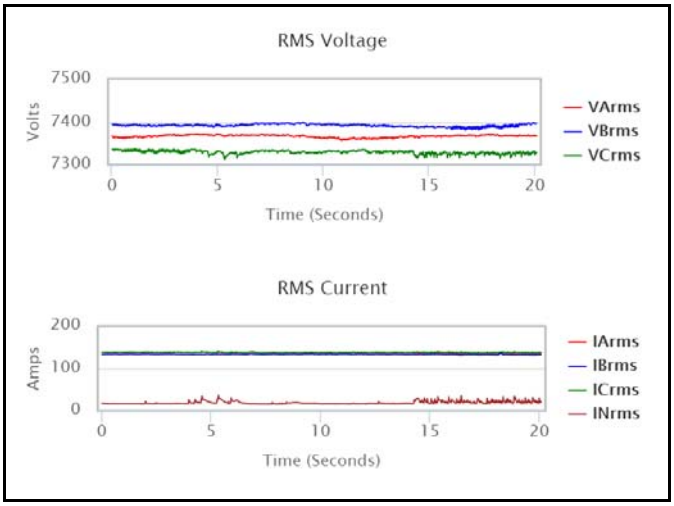

Fig. 13. Twenty seconds of RMS data during series arcing (clamp) flare-up

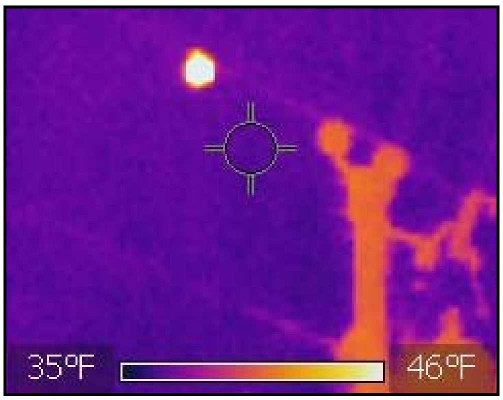

Fig. 14. Infrared scan of hotline clamp detected for one week by DFA

Fig. 15. Hotline clamp and stirrup found after one week of series arcing

IX. Improvements to DFA Capabilities

Texas A&M Engineering began its focus on DFA research in 1997. Much has been learned about failures of line apparatus and the resulting signatures represented in line currents and voltages, but there remains much to be learned. Field demonstrations and interactions with utility personnel continue to improve understanding. As this happens, DFA software can be modified and improved.

DFA system architecture anticipates improvement and expansion of DFA software functionality over time. In the DFA system architecture, the Master Station, in addition to being responsible for retrieving data from a fleet of DFA Devices, also provides the mechanism for deploying updated software to those devices. This architecture enables software updates to the devices, with minimal manpower and without requiring personnel to visit the substations.

X. Conclusions

Electric power distribution circuits are robust and generally operate reliably for decades. Conventional technologies for operating distribution systems provide little awareness of circuit events, until outages occur. Even then system operators often remain unaware of outages and other problems, particularly those affecting small numbers of customers, until someone calls to report loss of service.

Texas A&M Engineering has developed DFA technology, which is an information tool to provide engineers, operators, and other utility company personnel with improved awareness or visibility of circuit events. The system continuously monitors conventional substation-based CT and PT signals and automatically applies specialized analysis software to report circuit events, without requiring downstream communications.

Eight Texas-based utilities, including six cooperatives, are conducting field demonstrations of DFA and have fitted approximately sixty circuits with the technology. They have used DFA-provided information, often in conjunction with existing tools, such as electronic circuit models and AMI systems, to discover and correct a substantial number of circuit issues.

Additional field data and interactions with utility personnel enable developers to improve DFA software over time.

XI. References

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XII. BIOGRAPHIES

Carl Benner (Fellow 2014) holds B.S. and M.S degrees in Electrical Engineering from Texas A&M University in 1986 and 1988. He serves as Research Associate Professor the Department of Electrical and Computer Engineering at Texas A&M University. His work centers on the application of advanced technologies to the solution of challenging power system problems, with an emphasis on waveform analytics. Mr. Benner is a registered Professional Engineer in the state of Texas. He is a member of the IEEE Power and Energy Society and Industry Applications Society and a member of CIGRE.

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Before coming to PEC, Peterson spent 12 years at TU Electric (now ONCOR) in Engineering Planning, Design, and Standards.

Mr. Peterson earned his Bachelor's degree in Electrical Engineering from the University of Texas in 1980 and a Master of Business Administration from the University of Dallas in 1990. He is a registered Professional Engineer in the state of Texas.

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