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Using Waveform Analytics for Asset Management Operational Case Studies

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SUMMARY

Distribution circuits consist of thousands of components dispersed across a wide geographic area. Most apparatus have decades of expected service life, but all equipment eventually fails. Given these factors, periodic maintenance on distribution circuits is typically reserved for high-value components; most apparatus are operated until they fail, at which point a crew will be dispatched to repair the problem.

Over two decades of research has demonstrated that as components fail, they often produce electrical activity that can be detected in current and voltage waveforms measured at the substation. Some equipment fails catastrophically with little warning. In many cases, however, there is an extended amount of time between the first indications of failure and a final event which may cause an outage. Operational experience has shown that if a utility has proper information that a component on a circuit is in the process of failing, line crews are frequently able to find and fix the failing equipment before it reaches its final failure.

Researchers at Texas A&M University have spent two decades collecting and analysing real-world failure signatures from over 300 distribution circuits across the world. Data collection devices monitor substation currents and voltages on a per-circuit basis. Distributed sensing and communications are not utilized. Each device continually monitors currents and voltages, recording high-fidelity snapshots of data during transient conditions.

Based on waveform signatures combined with utility feedback, researchers have developed a variety of sophisticated classification routines which automatically alert utilities to potential issues developing on their circuits. Where possible, this system seeks to provide users with plain-text, actionable information, rather than requiring them to be experts in waveform classification.

KEYWORDS

Fault anticipation, Condition based maintenance, asset management, waveform analytics

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Introduction

The maintenance of distribution circuits poses multiple challenges for utility companies. Distribution circuits consist of thousands of components including switches, transformers, clamps, conductor, insulators, and the like. Many of these components have an expected lifetime of multiple decades, but all equipment eventually fails. Because distribution feeders are often spread out over tens or hundreds of square kilometres, inspection of individual components is time consuming and expensive. As a result, most apparatus on distribution circuits are operated in a run-to-failure mode, at which point a customer will call and a crew will locate and repair the faulty component.

The health of some high-value components, including large transformers, reclosers, and capacitor banks, may be assessed using periodic maintenance. For example, a utility might inspect all switched capacitors and reclosers on their circuits on a yearly basis. While this is certainly an improvement over a strict run-to-failure approach in terms of identifying failing apparatus, it remains less than optimal for a number of reasons. First, equipment can remain in service for an extended period of time misoperating or failing to operate until it is inspected. For example, consider a capacitor bank which blows a fuse the day after a crew inspects it. Assuming the utility had no other means of monitoring the bank, it would switch in an unbalanced state for the next 364 days until a crew visited it the following year. While this is the most extreme example, for a large enough sample size the expected time before discovery and repair would be six months, assuming a uniform likelihood of the equipment failing on any given day. Moreover, decades of research has documented multiple cases where crews performing annual maintenance actually introduced a problem which would have persisted at least until the crew visited the bank for its next service. As an example, a crew might accidentally set the clock of a capacitor controller incorrectly by 12 hours, resulting in the capacitor switching on in the evening and off in the morning, rather than the opposite as intended. Such a failure might not be noticed by subsequent crews, particularly if they only test the operation of the bank and note the number of operations. Finally, because most equipment inspected during routine maintenance is perfectly healthy, much of the effort and expense of routine maintenance will be unnecessary.

Recent advances in the availability of high-fidelity waveform recordings combined with advanced signal processing and analytics have enabled the development of technology which can, in many cases, alert utilities to early and impending failures on their distribution circuits [1]. One instantiation of this technology, Distribution Fault Anticipation (DFA), was developed in close consultation with over three dozen utility companies over a period of two decades and draws on over 1,500 circuit years of actual system operational data. This research has proved conclusively that many types of apparatus failure are preceded by many hours or days of signatures which, when presented to a utility operator in an timely manner can allow the utility to find and repair incipient conditions before they result in a catastrophic failure. DFA automatically records, analyses, classifies, and reports a variety of normal and abnormal power system operations directly to utility operators.

Waveform analytics – conceptual overview

The core premise behind waveform monitoring and analytics systems like DFA is the recognition that as apparatus operate, both normally and abnormally, they produce electrical signatures in current and voltage waveforms, many of which can be detected from the substation. Research has shown that while some failures are precipitous and therefore difficult to operationalize, many failures modes can persist over a period of days, weeks, or months without causing an outage or enough nuisance for a customer to call. Across dozens of cases at multiple utilities, it is not uncommon for advanced waveform monitoring and analytics to provide the *only* indication that a failure is in progress. The following statement sounds obvious, but is often overlooked: knowing a problem exists is the *sine qua non* to initiate corrective action.

With that said, simply collecting waveform data is not sufficient for an operational system. Because many failure events manifest as electrical disturbances smaller than that produced by normal load events (e.g. motors starting, etc.), any system designed to detect incipient failures will either produce large amounts of data that quickly overwhelms human operators, or be desensitized by operators to the point where it can no longer detect early-stage failures – unless the system is able to effectively triage actionable events. For a waveform analytics system to be operationally useful, it must 1) detect and record signatures with sufficient fidelity to enable classification 2) determine that a particular signature or set of signatures is "important" based on some criteria, and 3) report that information to a utility operator or engineer in a concise and timely way, along with information that enables corrective action.

Finally, one common misconception among many engineers is that "incipient" is synonymous with "low current." In truth, incipient events can produce both high and low magnitude events. For example, consider the case of a failure in an inline device such as a hot line clamp. For clamps or switches with only a small amount of connected capacity past the device, the failing clamp may produce transients with only a few primary amperes of current, with almost no perceptible change in voltage. On the other hand, consider the case of a vegetation-caused fault which either pushes two conductors together. Documented cases have shown these failure mechanisms can cause dozens of faults which operate upstream reclosers, each of which represents an incipient failure signature and indication of an underlying problem. In such a case, the utility might assert that these faults aren't "incipient" because they have already occurred. This misses the important point that the series of faults, taken as a whole, indicate that *future faults* are likely to occur, because the pattern of previous faults indicates an underlying failure condition that has not been remediated.

Distribution Fault Anticipation – hardware and software platform

Distribution Fault Anticipation (DFA) is a waveform monitoring and analytics system developed at Texas A&M University based on over two decades of research in cooperation with dozens of utility companies. Over the course of the DFA project, researchers have instrumented hundreds of operational distribution feeders with sensitive monitoring equipment to create the largest database of waveform signatures containing naturally occurring failure events in existence. Based on this data, researchers developed a series of algorithms to automatically analyse and classify waveform recordings with no a priori knowledge of what they might contain, and present actionable information to utility operators for the purpose of improving situational awareness and operational efficiency.

The DFA platform relies on specialized hardware devices installed on a one-per-circuit basis in distribution substations. The devices connect to standard current and potential transformers (usually feeder CTs and bus PTs) in the substation. Because incipient failure mechanisms can manifest with both low current and high current signatures, DFA devices use 24-bit analog-to-digital converters which produce recordings with approximately 19 effective number of bits. This allows the DFA to accurately characterize waveshapes of only a few amperes in the presence of normal load current, but also allows DFA devices to accurately measure high current pulses of thousands of amperes without saturating. DFA devices also have substantially more sensitive triggering than most traditional devices (relays, digital fault recorders, power quality monitors), and record substantially longer records. In the limit, DFA devices can record continuously for several days without overwriting data [2].

Once a transient signature has been recorded, algorithms on the DFA device analyse and attempt to classify the signature. The DFA algorithms also check historical events on each circuit to determine whether the event has similar characteristics to other events the circuit has seen recently, which may be an indication of a developing problem. These algorithm reports are then dispatched to a central server (the DFA Master Station) for dissemination to utility personnel. In most conditions, a DFA report will appear as a line item on the DFA Master Station for utility users within a minute of the event's occurrence.

Case Study 1: DFA monitors vegetation-induced failure
A key feature of DFA is its ability to identify faults on a circuit which may be related to each other [3]. Most faults on a distribution system are singular, self-healing events – for example, an animal bridging the bushings on a poletop transformer, etc. Sometimes, however, faults are caused by an underlying condition that persists even after a successful reclose. If the root cause of the fault is still present after the reclose attempt, the fault will continue to "recur" until the condition is discovered and remediated, or until the event progresses to a catastrophic failure. DFA analyses all faults on a distribution circuit and displays faults with similar characteristics as "recurrent faults."

−		Single-phase recurrent fault	A	Single-phase fault, 568 Amps	3 (34 days)	2021-07-02 21:12:16 CDT

Export Show 10 entries Search:

Event Type	Phases	Comments	Count	Last Occurred	Graph
Single-phase reclose	A	F-(3.5c,582A,AN)-T-(24,5,8)%-2.0s-C Est imp (ohms): 23.29z = 15.62r + 17.27x	1 op	2021-07-02 21:12:16 CDT	
Single-phase reclose	A	F-(3.5c,554A,AN)-T-(31,0,0)%-2.0s-C Est imp (ohms): 24.35z = 17.31r + 17.12x	1 op	2021-06-02 13:43:42 CDT	
Single-phase reclose	A	F-(4.0c,570A,AN)-T-(64,10,19)%-2.0s-C Est imp (ohms): 23.74z = 16.71r + 16.86x	1 op	2021-05-29 00:01:08 CDT	

Figure 1: DFA recurrent fault report

Figure 1 shows a typical DFA report an operator might see for a recurrent fault. In this case, DFA has detected three single phase faults all of which have similar characteristics that occurred over the preceding 34 days. The report in Figure 1 was generated automatically with no human action. Utilities with a competent system model and engineering analysis software (e.g. CYME, Windmill, Aspen) can use information provided in the DFA report to narrow the location of the fault. Feedback from utilities suggests these location estimates are often accurate to within a few pole spans, which is close enough for an experienced line crew to locate a developing problem.

In 2016, shortly after a DFA unit was installed on a distribution feeder, DFA began to report a phase-to-phase recurrent fault condition. This unit was installed as part of an evaluation project at a utility, which made the decision to deploy DFA in a "blind study" mode. This meant that all DFA units would report information as normal to the utility's research group, but that information would not be passed along to operations personnel, and no field action would be taken unless something was reported through the utility's normal operational channels. Over the course of two years, the DFA algorithms identified, clustered, and reported 44 instances of a recurrent fault condition, which continued in the same span. DFA researchers also investigated weather data at the times the events occurred and discovered that the faults coincided with wind above a certain speed from a particular direction. This, combined with the phase-to-phase nature of the faults, strongly suggested either a conductor clash event, or vegetation pushing two conductors together. Figure 2 shows three of the forty four faults, one from 2016, one from 2017, and one from 2018. It is immediately clear from looking at the waveforms that these faults have the same cause and are occurring at the same location on the system.

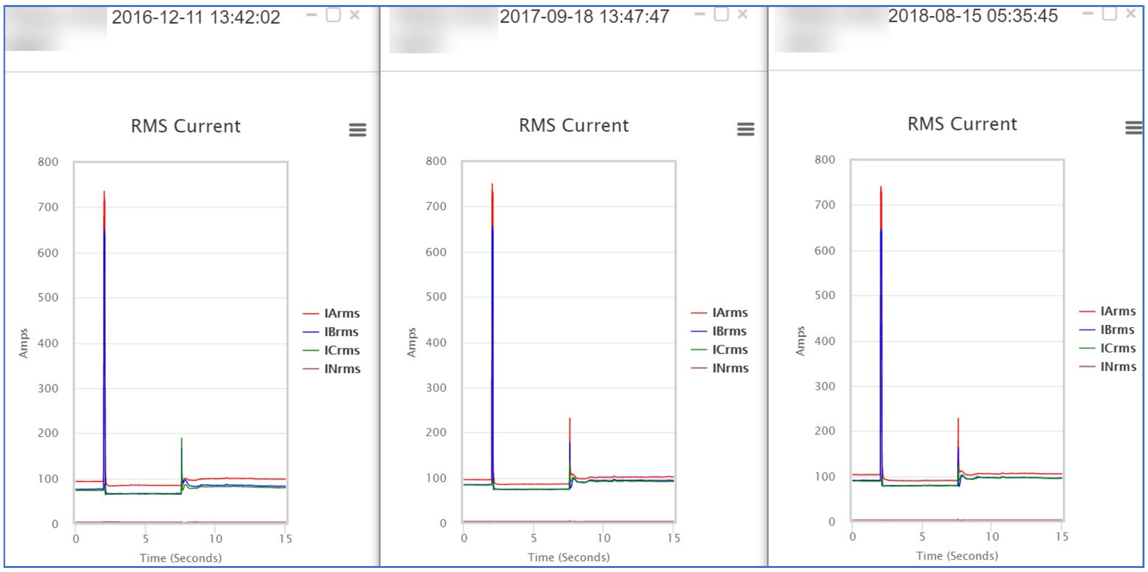

Figure 2: Three of forty four fault recordings from vegetation-caused event

After two years of repeated faults at the same location, the conductors suffered enough damage that one of them burned in two, causing a sustained outage.

This case study illustrates several important points about the operational use of waveform analytics. First, it demonstrates that incipient events are not restricted to low-current phenomena. While DFA could not have prevented the first or second faults in the sequence – or possibly even the third – by the fourth fault the utility certainly had opportunity to find and fix a problem that was clearly continuing. Even if it is not possible to prevent the first three faults, certainly preventing the subsequent forty-one and the conductor burndown would have value to a utility.

Second, having a record of individual faults is a necessary but not sufficient condition for a utility to take corrective action. In this case, the utility had communicating reclosers which produced a record of every fault on the circuit. For the time period of this event, the circuit in question experienced over 200 fault events, the majority of which were not related to the incipient condition – and indeed, the utility's communicating reclosers had a record of every one. The key piece of information to action is knowing that forty-four of the over 200 faults were *the same fault*, which would continue to recur until fixed.

Finally, this case illustrates how long some incipient conditions can occur before a final failure. DFA detected forty-four events over a two-year period. Because the first event occurred within a short time after the device was installed, it is reasonable to assume that the event may have been present even before DFA was installed. In any event, dozens of momentary interruptions spanning two years, and the conductor burndown could have been prevented with timely action.

Perhaps the most clear takeaway from this case, however, is that information – even perfect information – will not produce good outcomes unless a utility chooses to act on it. In this case, the utility's specific reasons for not responding to DFA-supplied information were complex, but their story is not unique. Even utilities which have integrated DFA reports into their operational workflow have occasionally used DFA information to identify problems in the field that were subsequently put on a repair list, but not prioritized until they resulted in another recurrent fault. No amount of information supplied by "smart" systems can replace sound engineering judgement, or a commitment to action.

Case Study 2: DFA helps utility locate a failing substation switch

Early on a Saturday morning, a DFA device began reporting severe series arcing at a 25kV substation with three circuits, serving 2,000 customers. Series arcing is a poorly understood phenomena from a scientific point of view. A theory generally consistent with observed cases is that degraded contact surfaces of a clamp, switch or other load-carrying device create a "hot spot" that behaves as a highly variable electrical impedance which "modulates" the line voltage downstream of the device. Series arcing is highly intermittent and can persist for weeks before causing a catastrophic failure. Some cases of series arcing produce only small current transients (on the order of a few amperes), but in some cases series arcing transients can be large enough to operate protective devices. DFA has documented cases where series arcing operated reclosers upstream of the failing device, and perhaps non-intuitively also cases where series arcing caused downstream protective devices to operate. Locating series arcing is not as straightforward as locating a low-impedance fault, because the magnitudes of current transients produced by series arcing are not driven by system impedance, but rather by the amount of connected transformer capacity past the failing device. DFA attempts to give a gross estimate of downstream connected capacity, but its estimates should be understood in terms of "a little" or "a lot," rather than a highly accurate prediction.

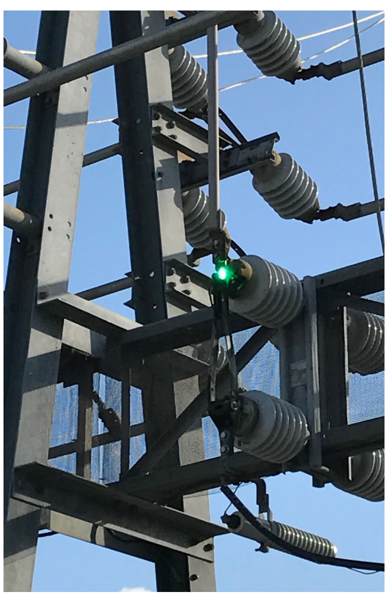

Figure 3: Substation switch identified by DFA

For the case in question, DFA reports suggested that almost all the circuit load was downstream of the failing device. The utility dispatched a crew to the affected substation, and on arrival the crew immediately heard buzzing coming from a substation blade switch. Figure 3 shows a picture of the failing switch, with the "hot spot" clearly visible. Because the switch was on the bus side of the breaker, a failure would have interrupted all circuits, causing a sustained outage for all 2,000 customers.

After locating the switch, the utility immediately brought in a crew to begin repairs, which were completed later that evening. During the roughly ten hours of series arcing, there were no outages, the utility received no customer calls, and no other system the utility had (SCADA, smart meters) indicated any problem with the circuit. In this case, DFA provided the only notice of an incipient condition, allowing the utility to fix the problem before it escalated. While it is unknown how long the switch would have continued arcing absent repair, in this case, utility action was likely "just in time." A storm blew through the area the next day, and it is likely that rain or through-fault current would have failed the compromised switch.

Case Study 3: DFA detects vacuum switch failure

A special case of series arcing occurs during failures of switches used to connect capacitors to the circuit. Capacitor arcing is a particularly pernicious problem, because it is capable of producing severe power quality issues (transients) for a prolonged period of time. Additionally, these transients are seen by all customers attached to the bus, and are capable of causing failures in other apparatus (blown fuses, failures of other capacitors, violent failures of arresters), even at distant locations. Capacitor arcing has been implicated as a wildfire ignition mechanism.

Early one morning, a DFA device registered an unbalanced capacitor switching event. Specifically, the event suggested that two phases of a 900 kvar bank switched off, but one phase remained on. Shortly after the unbalanced switch event, the DFA device began reporting sustained capacitor arcing.

Figure 4 shows the real and reactive power that resulted from the capacitor switching event. The reactive power shows all three phases opening initially, but approximately two seconds later, Phase B resumes conducting current, even in the "open" position. The continued presence of capacitor arcing suggested the switch had likely suffered a loss of vacuum. Armed with specific information about the failure (an arcing capacitor, specific circuit, Phase B, 900 kvar bank), a lineman located the switch and initiated repair.

Figure 4: Real and reactive power from vacuum switch failure

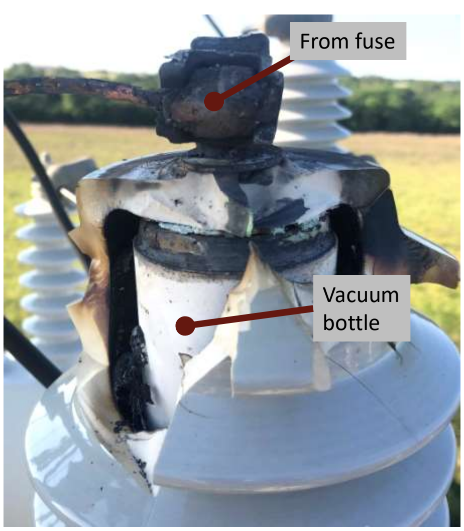

Figure 5: Failed vacuum switch

Figure 5 shows an image of the failed vacuum switch. As with other cases presented in this paper, DFA provided the only notice to the utility of a problem. DFA information was actionable, enabling a lineman to drive to the bank and replace the faulty switch, which had clearly suffered substantial damage. Replacing the switch in an expeditious manner helped the utility avoid the numerous effects of capacitor arcing, including ongoing power quality issues and the failure of additional line apparatus, at least some of which could represent ignition mechanisms.

Conclusion

Advanced waveform monitoring and analytics has the potential to transform the way utilities operate their systems [4]. While not all failures can be anticipated, many have distinct signatures which, when presented to system operators as actionable information, allow for proactive repair of failing apparatus, before the failure progresses to a full outage. One such technology, DFA, draws upon decades of field experience and actual circuit failures to automatically identify and report many failure events in their earliest stages, allowing utilities to operate their systems more effectively, efficiently, and safely.

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