Application of Waveform Analytics for Improved Situational Awareness of Electric Distribution Feeders

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***Abstract*—Over the past several years, distribution utilities have invested heavily in installations of "smart-meter" advanced metering initiative (AMI) systems. Among the anticipated benefits of these systems, utilities with smart-meter deployments are generally able to quickly assess which portions of their systems are operating normally and which customers are experiencing an outage. Projects at multiple utilities have focused on integrating AMI information, along with traditional supervisory control and data acquisition data sources, into utility distribution management systems to improve situational awareness on distribution feeders. Despite the clear benefits each of these systems offer, their ability to provide utilities with broad awareness of events affecting the health and status of the distribution system is limited, and often reactive in nature. This paper presents never-before-published cases observed in real-world field trials, detailing how integration of waveform analytics into utility operational practice leads to improved situational awareness.**

***Index Terms*—Condition-based maintenance, fault anticipation, incipient fault detection, situational awareness, waveform analytics.**

I. Introduction

FOR DECADES, the *de facto* standard for situational awareness on electric distribution feeders has been information obtained from supervisory data acquisition and control, or supervisory control and data acquisition (SCADA) systems, integrated into a utility's distribution management system (DMS) [1]. Recently, utilities have invested significantly in the deployment of advanced metering initiative (AMI) or smart-meter systems, which provide additional data as an input to an already existing DMS [2]. Various proposals exist for integrating even more data sources into utility DMS systems, including crowdsourcing from customer's social media posts using specific hashtags during outage conditions [3], installing distributed sensors along feeders, and receiving data from customer's home area networks (HANs), all with the hope that more data will inevitably lead to more information, and therefore more awareness [4].

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These technologies do provide clear benefits to utilities, but they suffer from several shortcomings when specifically evaluated with regard to efficacy for situational awareness. SCADA systems often provide low-resolution data, such as the open/closed status of breakers, and perhaps limited status of line voltages and currents. AMI systems can provide on-demand snapshots of customer usage and service continuity, but often are not programmed to record any information beyond billing and usage data, polled at specified intervals (e.g., every 15 min) [5]. The wide proliferation of smart phones equipped with global positioning system (GPS) and cameras can help utilities improve their allocation of crews during outage response, and particularly in storm restoration, by crowdsourcing reports and photographs of damage at specific locations, but this method of operation is generally employed during disaster response, not integrated into the normal course of daily workflow. At many utilities, the cost of installing distributed sensors at multiple points on every distribution feeder is prohibitively expensive, and the quality of alternative sensing technologies should not blindly be considered to be accurate [6]. While the "Internet of things" may, in the future, revolutionize the way utilities interact with "the load" by offering the capability of initiating demand response in near real-time, few HANs exist today, and, even setting aside the inevitable privacy concerns that arise when a utility collects and maintains usage data for specific customer devices, practical two-way communication and control systems for full utilization of HANs are likely many years from ultimate commercial deployment.

With rapid expansion in both the types and volumes of data fed into a utility's DMS, the industry has become broadly aware that an increase in data is not a sufficient condition for improvements in situational awareness or operational efficiency [7]. Indeed, while many utilities believe their current DMS systems, combined with AMI and SCADA inputs, are theoretically capable of providing ancillary functions to improve situational awareness, asking a utility to "show me the dashboard," enabling that functionality is often met with the reply, "We do not have that implemented … yet" [5]. A variety of research projects are attempting to resolve these challenges, but the extent to which "big data" correlations of statistical data can analyze disparate data sources and produce actionable information about the health and status of a utility's distribution system is uncertain [8].

A larger philosophical shortcoming of many proposed systems, however, is that the model of "awareness" they envision tends to be fundamentally reactive in nature, with the main benefits provided after an outage has already occurred. Few systems focus on providing increased awareness during the preoutage state of distribution circuits, when a prefailure condition, if detected, could be prevented, avoiding an outage entirely. A system which improves awareness during outage conditions to speed restoration is clearly good; a system which allows a utility to discover, fix, and avoid a potential outage is even better; a system which does both is best.

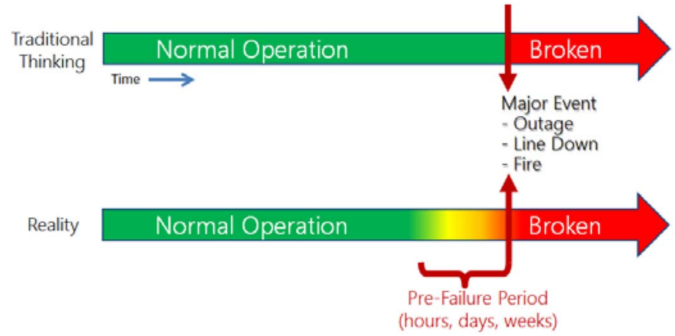

Fig. 1. Two paradigms of feeder health.

II. Waveform Analytics for Improved Situational Awareness

In contrast to information obtained from SCADA and AMI systems, which are typically single data points collected over a period of minutes, waveform analytics operate in real-time on high-speed, high-fidelity signals to detect anomalies in line currents and voltages, which are indicative of normal and abnormal power system events. By analyzing these signals and determining their root cause, waveform analytics can present utilities with a more complete picture of the health and status of their system, both during outages and normal operating conditions, as well as providing a variety of operational benefits to system operators, asset management personnel, and repair crews. Lest there be any misunderstanding, the authors are not suggesting that waveform analytics are a replacement for SCADA/AMI technologies, but rather an orthogonal extension which allows new levels of awareness not possible with SCADA/AMI alone.

For many utilities, the concept of "situational awareness" regarding the health and status of their systems is tightly coupled with both periodic maintenance and outage response. The maintenance approach traditionally employed by many utilities can best be described as an "operate to failure" philosophy. This is not meant as a criticism: given the techniques and tools available, and the nature of distribution systems, this result is understandable, and perhaps inevitable. Distribution feeders contain many hundreds or perhaps thousands of individual components, dispersed across a wide geographic area. While companies do perform periodic maintenance and inspection of certain "high-value" components such as transformers, circuit breakers, and capacitor banks, the vast majority of components and apparatus on a distribution circuit remain in service until they fail, at which point the utility discovers the failure, often because customers call to complain that their power is out. The utility then dispatches a crew to replace or repair the failed equipment, thus restoring power to customers.

Consequently, a typical utility's awareness of the health and status of its system is generally understood in binary terms: "Everything's fine!" if all customers have power, or "It is broken!" if there is a sustained outage.

Research performed over the last two decades demonstrates that instead of transitioning instantaneously from "working" to "broken," many power system components fail over an extended period of time, and in the process of failing produce electrical signatures which are detectable as variations in currents and voltages, as measured by substation feeder-current transformers (CTs) and bus-potential transformers (PTs) [9]. By detecting these variations, automatically determining their root cause, and providing utilities with actionable, line-item information about critical apparatus which may be approaching ultimate failure, waveform analytics offer utilities the possibility to drastically improve their knowledge about and awareness of the health and status of the components on their system, and enable corrective action where appropriate.

Fig. 1 illustrates the contrast between these two paradigms of feeder health. The top arrow represents the paradigm of situational awareness available to and employed by most utilities: "normal operation" transitions instantaneously to broken at the point of a major event. By contrast, improved situational awareness enabled by waveform analytics informs a utility when it has entered the prefailure period, allowing it to remediate apparatus before the system reaches the broken state.

III. Distribution Fault Anticipation System Overview

One such waveform analytics system, distribution fault anticipation (DFA) technology, has been developed over a period of two decades in collaboration with the Electric Power Research Institute and over a dozen utilities across the U.S. and Canada. Over that time, utilities have instrumented dozens of distribution feeders for up to eight years with advanced waveform monitoring devices, resulting in the largest extant database of waveform signatures of normal and abnormal power system events [9]. Careful analysis of recorded events enabled researchers to design algorithms, based on advanced signal processing and pattern matching techniques, which are able to identify the root cause of both normal and abnormal power system signatures without human input. Once the root cause of an event is determined, the DFA analytics engine searches a historical record of events on the monitored circuit to determine if the present event's characteristics match those of past events on the circuit. Digested reports and alerts about prefailures and device misoperations are then generated and transferred to a centralized server for dissemination to the appropriate utility personnel.

At a high level, the DFA system consists of large numbers of high-speed, high-fidelity waveform monitoring devices, each of which are equipped with onboard waveform analytics,

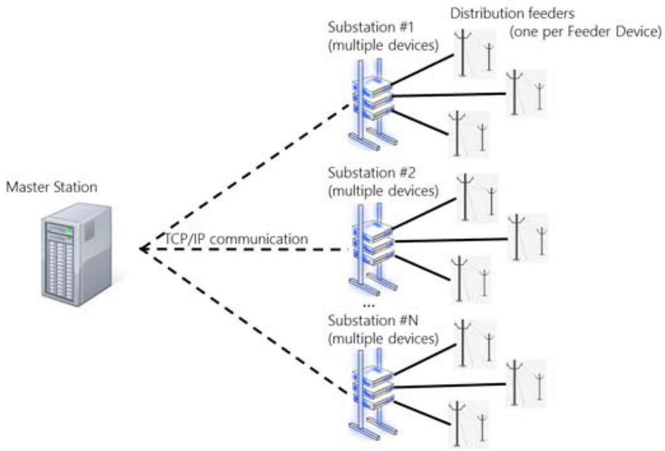

Fig. 2. Architecture of a typical DFA deployment.

installed in substations on a per-feeder basis, and communicate with a centralized utility server. A representation of a typical DFA system deployment can be seen in Fig. 2. In contrast to systems which transfer all waveform data to a central location for processing and analysis, the DFA system performs all waveform analytics functions on the device in the substation, improving both scalability in large deployments and system response time during periods where a large amount of data is generated in a relatively short time (e.g., storms). Reports and alerts, summary information about all events, and waveform data from important events (e.g., overcurrent faults, potential prefailures, and misoperations) are transferred to the centralized server, which collects, aggregates, and disseminates actionable information to utility personnel via Web, email, and SMS alerts.

DFA waveform monitors accept traditional substation feeder-CTs and bus-PTs as inputs, and do not require any distributed communication to downstream feeder devices. Rather, the analytics in the DFA waveform monitors infer the presence of downstream devices (e.g., hydraulic relcosers, capacitors, etc.), as those devices operate.

Utilities who have integrated DFA-provided information into their operational procedures have demonstrated the potential of waveform analytics to improve situational awareness, shorten outage restoration times, and in many cases, avoid outages through targeted, proactive condition-based maintenance [10]. These utilities have demonstrated that many events which, based on typical practices would almost certainly have resulted in an extended outage, can be identified and prevented before a catastrophic failure or outage, thereby improving reliability metrics for the utility, and quality of service for the customer.

IV. DFA Waveform Analytics

Many waveform analytics systems are designed to detect a specific class of events. As a trivial example, most commercial power quality meters (PQMs) have internal waveform analytics to automatically detect multiple classes of voltage events, such as voltage sags and swells. More advanced meters might have the ability to classify an event as a capacitor operation. Because many of the benefits of waveform analytics systems come from detecting abnormal operations, many of these systems focus on attempting to set appropriate thresholds such that "important" events are captured, while "normal" events are not. Philosophically, these systems attempt to determine *a priori* characteristics of important events, and focus only on recording events with those characteristics (e.g., "We have observed that if we see two pulses of X magnitude within Y milliseconds, that corresponds to an event of type Z, so if the device observes two pulses of magnitude X within Y milliseconds, record a waveform, because it is likely important").

By contrast, the DFA waveform analytics.

1) Assume nothing *a priori* about the identity or importance of any specific waveform.
2) They are designed to discriminate important from normal events after they have been recorded, based on signatures within the recorded waveforms.

Consequently, the DFA system triggers much more sensitively than many other waveform analytics systems, generally triggering waveforms when changes of one percent in voltage, or as low as 10 A of current are observed. The DFA waveform analytics then perform detailed analyses on the recorded waveforms, attempting to determine the underlying cause of the waveform. The "DFA waveform analytics" are not simply one "algorithm," but rather a suite of dozens of algorithms, attempting to classify a recorded waveform of unknown cause, with a high degree of confidence, to the underlying power system apparatus or operation which caused the observed phenomena.

Detailed explanation both of individual waveform analytics algorithms (e.g., for classifying an individual waveform recording as a motor start, or as an arcing capacitor switch, or a recurring overcurrent fault), and the inference engine which assigns probabilities to the likelihood of an individual waveform being caused by a specific event, are the subject of multiple theses and dissertations, and not suitable for discussion in a journal article. Parties interested in specific details of individual algorithms for particular event types, the accuracy of classification rates, or the electrical characteristics of events such as those presented in this paper should consult DFA patents, or the referenced publications [11]–[17].

V. Waveform Inputs for DFA Analytics

It seems obvious to say that waveform inputs to the DFA analytics engine must be of "sufficient quality" to characterize a wide variety of prefailure events. The nexus of factors which contribute to sufficient quality, however, are sometimes poorly understood within the industry. The requirements for input signals to the waveform analytics engine are readily achievable with modern electronics, but are often not implemented in commercially available hardware. Additionally, it can often be difficult to determine the suitability of a particular device simply by looking at its specification sheet or product literature. Discussions about the suitability of particular devices often begin and end with sample rate, but many other considerations are just as, if not more important. These factors include, but are not limited as mentioned below.

1) *Triggering Sensitivity:* Many prefailure events manifest as relatively low-level perturbations, in some cases only

a few amperes of primary feeder current, and almost no change in bus voltage. Because this level of activity falls well below the threshold for many normal events (e.g., motor starts), many commercial systems intentionally ignore such signatures, to avoid being overloaded with data.

2) *Range and Resolution:* Line voltages have a relatively narrow dynamic range, seldom exceeding 2 p.u. Line currents, on the other hand, vary widely during fault conditions, with magnitudes often approaching twenty or thirty times the feeder's current during normal operation. Detecting and accurately reproducing the signals for the low-level events described above, while simultaneously not clipping on bolted fault conditions (e.g., 100 A of current on the feeder CTs secondary winding) is challenging for most commercially available hardware.
3) *Waveform Record Length:* The maximum length of waveform records from commercially available devices is typically measured in the range of cycles to a few seconds. Certain prefailure event-types require tens of seconds or longer for proper characterization.
4) *Data Management:* Longer data records combined with more sensitive triggering results in the production of orders of magnitude more data than typical for commercial devices such as PQMs or digital fault recorders (DFRs). In some cases, many gigabytes of data can be generated in only a few hours. If the system is not designed to accommodate such high data volumes without human intervention, important events may be missed.
5) *Processing Power:* For the platform to remain scalable, all waveform analytics should be performed on the device itself, requiring a level of computational ability not present in typical commercial hardware.

At this point, engineers often demand quantitative bounds for the categories above. It is the authors' opinion that this line of discussion begs the question. When any of the above categories are not present in sufficient capacity, there will be limitations in the range and types of events that can be characterized. For example, a monitor which samples at 16 samples per cycle, with 12-bits of resolution, and records waveform lengths of 60 s would likely be able to adequately characterize overcurrent faults, sufficient to enable many of the functions performed by DFA waveform analytics. On the other hand, this same system would probably not have sufficient sample rate to adequately characterize capacitor bank problems, and would be completely unable to detect small incipient failures, such as an arcing hot-line clamp. A different monitor which sampled at 2048 samples per cycle with 24-bits of resolution, but which only recorded 2-cycles of information per waveform record would be almost worthless for most classes of events, even though its sample rate, range, and resolution were all far superior to the first hypothetical device. Furthermore, all categories above assume a competent analog signal path that does not introduce significant distortion or noise onto the measured signal. A third hypothetical device with a sample rate of 256 samples per cycle, 24-bits of resolution, and a signal path that introduced 8-bits of noise in the analog signal would not perform better—and indeed would likely perform worse in many respects—than a device which sampled at 128 samples per cycle and 16-bits of resolution, but which had a very clean signal path.

As a result, any discussion attempting to quantify sufficient quality must have: 1) detailed knowledge of the electrical characteristics for the various event types to be characterized; and 2) a nuanced understanding of how the factors above interact with each other, and how those interactions affect the characterize the events in question. In the development of DFA waveform analytics, researchers used hardware that sampled at 256 samples per cycle, with an effective resolution (after noise bits are discarded) of about 19-bits. DFA waveform monitors are capable of recording records of over 30 min in length, at full sample rate and resolution.

Each of these interrelated categories represents a necessary condition for the practice of online condition monitoring and situational awareness using waveform analytics, and therefore often renders many commercial devices and systems, including most PQMs and DFRs unsuitable for that application. Waveform signatures produced by initial prefailure events tend to fall below the triggering threshold of most devices, and tend to cause such small variations in current and voltage that commercial devices cannot properly characterize them even if they are recorded.

VI. Situational Awareness: Case Studies

The objective of the DFA system is to provide utility companies with actionable information about incipient faults, prefailures, and other misoperations, thereby improving the utility's overall situational awareness and operational efficiency. In over two decades of research and deployment, the DFA project has accumulated thousands of distinct signatures from failing apparatus and equipment misoperations. In most cases, the DFA system provided the utility's only notice of an impending problem. DFA devices have informed utilities about a multiplicity of problem conditions, including intrusion of vegetation into conductors, fault-induced conductor slap (FICS), dozens of distinct failure modes for capacitors, switch failures, clamp failures, problems caused by utility crews performing annual maintenance, and in one case the misoperation of a newly installed fault location, identification, and service restoration (FLISR) system. In addition to informing utilities about prefailures and misoperations on their system, DFA waveform analytics have aided repair crews in difficult to diagnose conditions, and have notified utilities when field repairs did not correct the underlying problem.

The following case studies are real-world events that occurred in the development and deployment of DFA waveform analytics systems. While these case studies highlight specific events, for each class of event presented below (e.g., FICS), researchers have observed multiple cases of the same phenomena occurring at other utility companies. In other words, the case studies presented below are not isolated events, but rather recent examples intended to be representative of the types of cases where waveform analytics prove beneficial to utilities, in actual deployment.

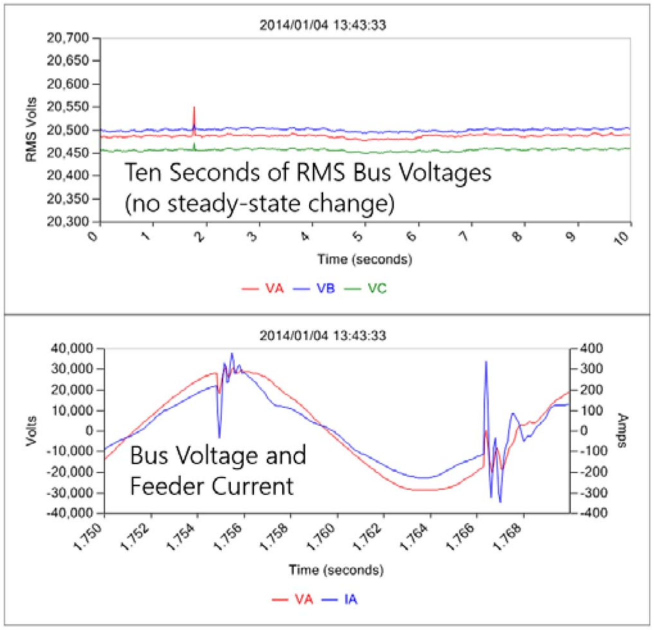

Fig. 3. Voltage and current waveforms from capacitor failure event.

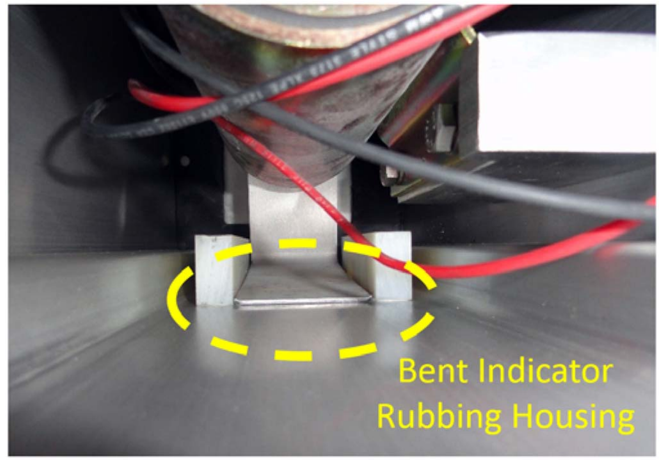

Fig. 4. Bent indicator on prefailure switch.

A. Detection of Prefailure of Capacitor Vacuum Switch

In two decades of deployment, the DFA system has detected dozens of individual failure mechanisms of capacitor banks on distribution feeders. Often, in the best case scenario, utilities are unaware of problems with specific capacitor banks until a crew performs periodic maintenance, usually on a yearly basis. If a bank experiences a failure shortly after a crew inspection, the bank may fail to operate, or potentially worse, may misoperate for almost a year, until the next crew inspection.

The following series of events occurred at a DFA-participant utility over a 2½ month period, beginning in late 2013. The utility in this case study utilizes one-way paging to switch its feeder capacitors. After each page, the system monitors substation VAR to verify that the bank successfully switched, and that the switching bank is balanced. In late November, a DFA waveform monitor began detecting a series of unusual transients which suggested the prefailure of a capacitor bank. Typical waveforms from this series of events can be seen in Fig. 3. The utility searched its trouble tickets and DMS system, but was unable to find any indication of a problem through conventional means. The utility and researchers continued to monitor the situation, and recorded over 500 separate instances of the transient over the next 2½ months. After 2½ months, increasing event activity suggested that the problem might be accelerating toward failure, prompting corrective action.

Normal capacitor switching causes two distinct waveform phenomena: 1) a short-lived high-frequency voltage transient; and 2) a step-change in voltage, visible even at the bus. Each of the observed waveform records contained a transient, but did not contain an associated step-change in bus voltage, indicating the event was not associated with a switching operation. Furthermore, the polarity of the current and voltage transients indicated that the problem was "behind" the DFA waveform monitor, meaning that the subject event was located either on an adjacent feeder, or on the bus itself.

In mid-February, after an increase in the frequency of events, the utility decided to take corrective action. To confirm the diagnosis of a prefailing capacitor, the utility sent a crew to pull fuses from all five capacitor banks located on the only other feeder attached to the bus. At the first bank, the crew found an anomaly. The "closed" current for the capacitor bank should be approximately 30 A. The utility's paging system showed this particular bank to be in an "open" state. When the crew tested the current in each phase, however, one phase registered a current of 0.7 A through the open switch. The crew pulled the fuses for the bank, but left the other four banks in service. The observed transients, which had peaked at a rate of twenty-one observations per day in the week prior to the crew pulling the fuses, ceased abruptly, indicating the diagnosis was correct.

The utility removed the prefailure switch from service and a root cause analysis was performed by an outside expert. After failing a hi-pot test, the switch was disassembled. This particular model switch has a sight window with a red/green position indicator for visual inspection of its open/closed status. The red/green indicator for the affected phase was bent, resulting in the indicator rubbing and binding against the switch housing, shown in Fig. 4, which in turn prevented the vacuum switch contacts for that phase from opening fully. The current flowing through the gap in the partially open switch is believed to have caused progressive internal damage to the vacuum interrupter.

The failure of a vacuum switch can have many potential consequences. In the least severe case, the affected phase will not switch, resulting in an unbalanced capacitor operation. In the most severe case, the switch or capacitor may rupture, potentially resulting in a fire or, if the rupture occurs while the switch is being inspected or serviced, serious injury to utility personnel.

DFA waveform analytics observed the prefailure of this vacuum switch for 2½ months before intervention. Normal operational practices, and the utility's state-of-the-art AMI system installed on this feeder, did not, and do not detect this kind of prefailure. The detection of the prefailure provided time—in this case at least 2½ months—for the utility to correct the underlying condition and preempt a full failure. In this particular case, DFA waveform analytics provided the utility with the only notice and opportunity to correct the problem proactively.

B. Detection of Failing Service Transformer

During a rainstorm, a fault occurred on a DFA-monitored feeder with over 125 mi of overhead line. A midpoint recloser tripped, momentarily interrupting 103 customers, at which point a downstream sectionalizer operated, resulting in a sustained outage for 82 customers. Utility crews responded to the outage and restored power, but left without finding a clear cause. Four days later, also during a rainstorm, a second fault momentarily tripped the same breaker, interrupting the same 103 customers, but this time reclosed successfully with no sustained outage.

All utilities would know about the first fault, since it resulted in an outage. In the process of restoration, particularly during and following storm conditions, it is not uncommon for the responding crew to reenergize the line, and, if it holds, leave the scene with a diagnosis of “no cause found,” “vegetation,” “lightning,” “bad fuse,” or similar cause code. Because the second fault did not result in an outage, most utilities would have no awareness it occurred, unless a customer called to report “blinking lights.” Research from DFA-monitored feeders has shown that customers rarely report momentary interruptions, even after repeated blinks [9].

In this particular case, the DFA analytics engine: 1) reported the first fault and associated outage; 2) reported the occurrence of the second, temporary fault, which caused a momentary interruption, but no outage; and 3) determined that the two faults had similar characteristics, even though their “outcomes” were different. The system then automatically generated a report which informed the utility of a recurrent fault on the circuit. Research has shown that a wide variety of failing line apparatus can result in repetitive overcurrent faults which manifest themselves over a period of hours, days, or weeks, with significant periods of quiescence, until they result in an ultimate failure that produces a sustained outage.

After the DFA system notified the utility of the recurrent fault, utility personnel compared information provided by the DFA report with their feeder model, narrowing the search area to a very small portion of the circuit. Patrolling only that area, crews found a service transformer with arc marks on its jumper wire, and a hole punched through its lid, shown in Fig. 5. The utility concluded that the adjacent vines, seen in Fig. 6, when weighed down by moisture, caused flashovers between the jumper wire and the lid, and that the resulting flashover arcs created the hole.

It is worth pausing to consider the course of action a typical utility, even one equipped with modern smart-grid systems, would take in this situation. A utility with only conventional sources of information would likely have no knowledge of the second fault, since it did not result in an outage. Obviously the utility cannot act to remedy a fault if it does not know the fault occurred. Even if a utility did know about the second fault, however, it is extremely unlikely that it would determine that the two faults, which occurred several days apart, were in any way related to each other. The fact that both faults occurred during a rainstorm, when temporary, nuisance faults are much more common, and are therefore unlikely to be perceived as part of a long-term, ongoing series of failures, would make the diagnosis even more difficult. In either case, even a utility with advanced smart-grid systems is unlikely to possess the information necessary to successfully remediate the underlying failure cause.

Fig. 5. Service transformer with damage to lid.

Fig. 6. Damaged transformer on the pole.

The result of this lack of actionable information is that, in this case, the damaged transformer would remain in service with a hole in its lid, enabling moisture ingress, and having a high likelihood of faulting again during the next rainstorm, with the associated potential of causing another outage. In a worst case scenario, the breached lid and moisture ingress might compromise the insulating quality of the transformer's oil, leading to an internal fault and possible explosion, with the subsequent expulsion of burning oil. Particularly in areas where wildfire risk is high, such an event, while rare, could have catastrophic consequences.

C. Detecting When Field Repairs did not Fix the Problem

Like in the previous case, this example involves the DFA system detecting, identifying, and informing the utility of a repetitive fault on its system. Unlike the previous case, however, in this example, the DFA system not only informed the utility of the existence of a potential problem, but also determined that the utility's initial repair effort did not fix the underlying issue.

Most repetitive faults encountered on distribution feeders involve a single phase and ground. In this example, however, a DFA-monitored feeder experienced multiple, similar phase-to-phase faults. The phase-to-phase nature of the faults ruled out many common causes of recurrent faults, including single-phase transformers, single-phase insulators, cracked insulators, and cracked bushings, all of which can cause recurrent faults.

The second episode of this series of faults occurred during a windy snowstorm, and resulted in an outage. As in the previous case study, a crew responded to the outage and restored power, but was unable to find any clear cause for the outage. After power was restored, the fault recurred twice in the next two hours. Each recurrence of the fault resulted in a single trip of a three-phase recloser, but no outage. Based on information obtained from the DFA reporting system, the utility initiated a search of the feeder, and replaced a set of faulty dead-end bells. This did not seem entirely consistent with the fact that the faults were phase-to-phase, however, since one would typically expect dead-end bells to cause single-line-to-ground faults.

For approximately two weeks, the problem appeared to be fixed. The fault then recurred sixteen days later, again during a period of significant wind. The DFA system automatically updated its fault current report based on the latest event, and based on that report the utility performed another search.

The feeder in this example runs through rough, rural terrain and has a span exceeding 1000 feet in length. In that span, a crew found that one of the conductors had a broken strand, which had unwrapped partially, and was protruding laterally approximately 10–12 inches in the direction of an adjacent conductor. The crew also found arc pitting on the adjacent conductor, consistent with past arcing contact. The crew determined that during windy conditions, the conductors in this long span were swinging together close enough that the protruding wire contacted the adjacent conductor, causing the observed faults. Repairing the conductor ended the series of recurrent faults.

It is again worth considering the course of action a typical utility would take in this series of events. In total, the fault occurred five times, tripping a three-phase recloser each time, but with only one occurrence resulting in a sustained outage. That singular outage occurred during a windy snowstorm, and the responding crew was unable to find any obvious cause. A utility equipped with conventional sources of information would know only about the single occurrence which caused an outage, and most likely would have ignored the event, concluding, reasonably so, that it was an isolated incident caused by the storm. By contrast, because the DFA system detected and identified the initial fault-and-reclose event which occurred before the outage, and the two reclose operations that shortly followed service restoration, and was able to determine that all four events were related to each other, the utility was informed that the outage was not an isolated incident, but rather was part of an ongoing series of interruptions, a series which was likely to continue unless corrective action was taken.

If, hypothetically, the crew responding to the initial outage had found and replaced the damaged set of dead-end bells, it is likely that a typical utility would have closed that outage ticket, and considered any new indications of breaker trips or outages to be a completely separate series of events, particularly if several weeks went by before the fault recurred, as was the case here. By contrast, the DFA system informed the utility that replacing the dead-end bells had not resolved the underlying issue, and did so on the first trip-and-reclose after the utility believed the problem to be fixed.

This example illustrates a benefit of improved situational awareness that is often overlooked: in some cases, repair crews responding to a trouble ticket, using standard diagnostic procedures and exercising reasonable judgment, fix legitimate problems on the feeder that were, unfortunately, not the underlying cause of the outage in question. Waveform analytics not only allow utilities to know when a potential problem exists, but also allow utilities to know when the underlying problem has not been successfully repaired.

D. FICS

One phenomenon which the DFA system has identified on multiple circuits at multiple utilities is FICS [18]. FICS occurs when magnetic forces from an initial fault cause movement in upstream conductors sufficient to cause the conductors to contact each other, resulting in a second, higher magnitude fault closer to the substation. In the multiple cases of FICS documented in the course of DFA research, conductor spans that experience FICS are generally found to have something unusual about their construction, such as extra length, extra sag, transition, etc., which makes the FICS event possible. As a result, if a span experiences an FICS event, it is likely to continue to experience additional FICS events, until the underlying construction problem is corrected, or, if left uncorrected, until repeated faults damage the conductor to the point it breaks. The DFA research program has documented multiple cases where FICS events recurred in the same span, but because months or years often pass between the occurrences, utility personnel often do not recognize the repetitive nature of the event.

In 2007, before DFA analytics could recognize FICS, a DFA-monitored feeder experienced an outage due to FICS. An initial 2800 A phase-to-phase fault occurred and

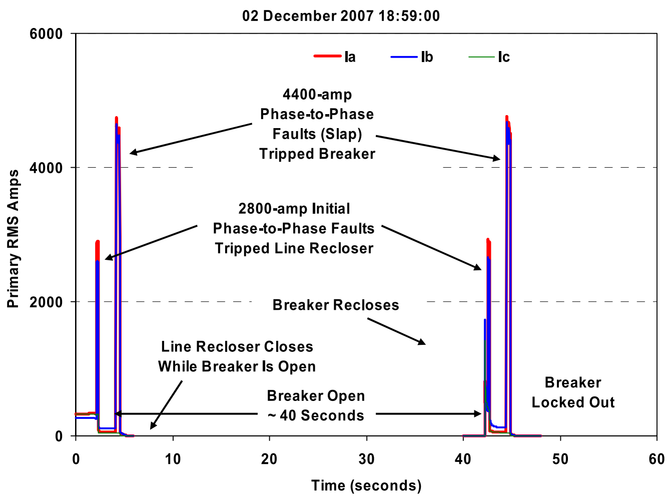

Fig. 7. RMS current waveforms for FICS sequence.

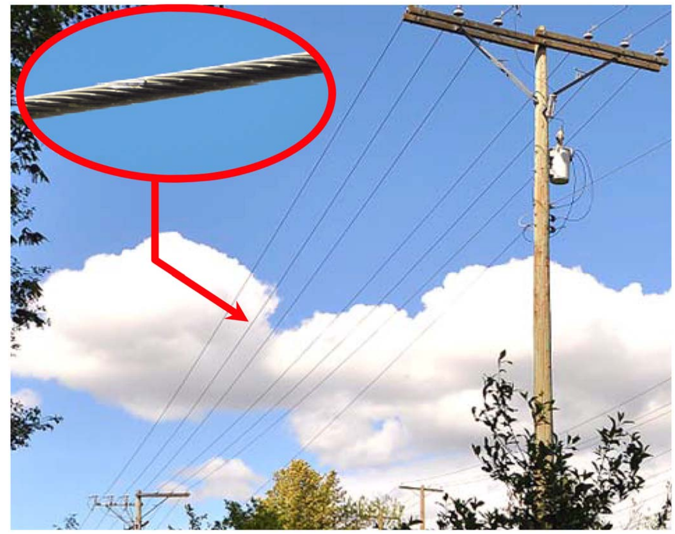

Fig. 8. Span with multiple FICS events.

tripped a midpoint recloser. The recloser trip was shortly followed by a higher, 4400 A fault which locked out the substation breaker. The feeder lockout resulted in an outage for over 4000 customers, whereas the initial fault should have tripped only the midpoint recloser. The sequence of events is shown in Fig. 7.

The utility company investigated the feeder lockout, using all of the tools available to them, except the DFA system. Utility personnel recognized that the event should have been sectionalized by the midpoint recloser, without operating the substation breaker. The utility expended significant time and energy collecting data and analyzing the event, but the effort resulted in a diagnosis of no cause found.

Two years later, FICS occurred again in the same span of the same feeder, resulting in another outage for all 4000 customers. Five days later, another FICS event occurred which tripped the substation breaker, but did not cause it to lock out. In the two years since the previous incident, DFA analytics had evolved to recognize FICS events, and informed the utility of the underlying cause. Based on a DFA-generated report, utility engineers were able to identify the susceptible span, pictured in Fig. 8.

The utility did not take immediate action to remediate the problem. In late 2011, another FICS event occurred on the same span, resulting in a feeder lockout and an outage for all 4000 customers.

Several observations can be made from this example.

1) FICS produces predictable patterns in waveform data, which can be detected and reliably recognized.
2) Spans which are susceptible to FICS tend to experience it repeatedly, until the underlying construction issue is resolved.
3) Utilities may recognize that their protection scheme did not operate as intended; i.e., the initial FICS fault should trip only the midpoint recloser, but instead results in an operation of the feeder breaker. Many utilities have expended substantial time and energy investigating FICS events, only to result in a diagnosis of no cause found, usually because of a lack of sufficient data and the complexity of the underlying phenomenon.
4) Perhaps most importantly, even if a utility possesses credible and actionable information about a problem on a circuit, that information is of little value unless the utility chooses to take action. The final FICS event on this span occurred at noon, on the day of a major North American holiday, just as many families were sitting down to enjoy their holiday lunch. While this is a particularly unfortunate case of dramatic irony, the point remains: no amount of improvement in situational awareness can improve reliability and operational effectiveness without corresponding action to remedy prefailures.

FICS represents an event where waveform analytics can automatically diagnose a complex phenomenon which usually goes undiagnosed, or can be misdiagnosed by skilled engineers equipped with traditional sources of information. The complexity of FICS events can also cause the misoperation of automated smart-grid systems, including FLISR systems, which have been observed to restore fewer than the maximum possible number of customers following FICS events. Finally, the frequency of observation of FICS events on DFA-monitored feeders suggests that FICS is a problem which may be more widespread, and occur much more often than typically believed.

VII. Conclusion

Over the past decade, utility DMSs have seen the integration of increasing varieties and volumes of data, with the assumption that increased data leads to better information and situational awareness. Many of the systems which feed information into the utility DMS, including AMI systems, provide substantial benefit to the utility and to customers, but their efficacy in truly improving situational awareness, outside of fault conditions, is unclear.

By contrast, advanced waveform analytics have demonstrated the ability to inform utilities about the condition and health of individual components on their system, including alerting utilities to prefailures and misoperations which, left alone, would result in outages and power quality problems. Additionally, online waveform analytics provide utility crews with new tools to aid in diagnosing field repairs which, absent analytics-supplied information, might require multiple trips to resolve. In summary, online waveform analytics provide a broad range of benefits that, collectively, offer utilities improved situational awareness and operational efficiency.

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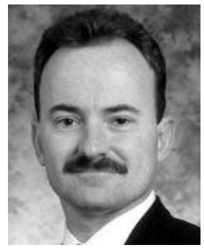

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