Incipient Fault Detection Through On-line Monitoring

Carl L. Benner and Dr. B. Don Russell
Department of Electrical and Computer Engineering
Texas A&M University

Abstract Operations and maintenance represent sizeable chunks of most electric power distribution utility companies' annual budgets. Line apparatus typically are maintained through time-based, preventative maintenance programs. Preventative maintenance consists of some mixture of inspecting, testing, and in some cases replacing components at fixed time intervals. Intervals are based upon historical experience and generally are conservative (i.e., frequent), to maintain acceptable system reliability.

According to a 1992 *Electrical World* article, "American industry spends more than $200-billion each year on the maintenance of plant equipment and facilities. Reportedly, about one-third of these maintenance costs are squandered and represent a loss of over $66-billion" [1]. Clearly, preventative maintenance is inefficient. It also can be ineffective, failing to diagnose problems that it was designed to find, and allowing failures to occur between intervals. In some cases, preventative maintenance has even been documented to introduce problems that otherwise did not exist.

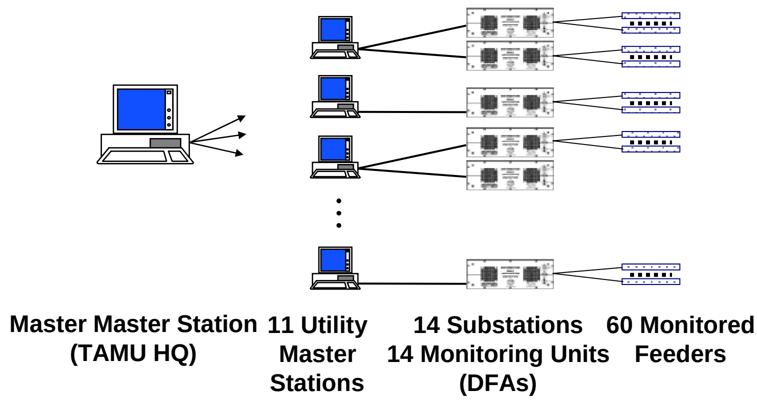
Utility companies practice preventative maintenance primarily because they have no other real choice for maintaining acceptable reliability. Since the late 1990's, research at Texas A&M University (TAMU) has been targeted toward a practical alternative. TAMU has instrumented substations at eleven utility companies, as part of a major research program sponsored by the Electric Power Research Institute. These Internet-accessible monitoring and recording systems have documented numerous instances in which various failure mechanisms have caused measurable electrical changes in advance of final failures. These measurements also have documented the progression of failures, which sometimes take hours, days, weeks, or months to evolve from incipient problems to failures and outages. In addition, measurements have shown how relatively simple operational problems with apparatus can escalate into more serious problems and even cascade into failures of other apparatus.

This paper will overview the instrumentation system and provide a series of case studies that give the reader a feel for some of the types of failures that can be seen with sensitive monitoring.

Project Overview Since the late 1990's, researchers at Texas A&M University have conducted research in the area of detecting and analyzing anomalous electrical signals that indicate fault precursors or operational problems with line apparatus. The Electric Power Research Institute has been a major supporter of this activity.

Texas A&M designed a sophisticated system for capturing and collecting high-fidelity waveforms and other signals. The exact nature of the signals that would be measured and recorded was unknown at the beginning of the project, because no one had systematically recorded this type of information before. However, it was anticipated that fault precursors would produce small current signals, certainly much smaller than the overcurrent faults that relays and fault recorders typically record. Therefore, the systems were designed to give wide dynamic range, with high resolution even at relatively small signal levels.

Individual units monitor the voltage and current signals of one to eight feeders in a given substation. Eleven utility companies across North America participate as data collection sites, with systems installed at 14 substations monitoring a total of 60 feeders. The data collection systems communicate with Master Station computers via the Internet. Each participating utility has a Master Station that collects data from that utility's system, and Texas A&M has a "Master Master" Station that collects data from all systems, as shown in the following figure.



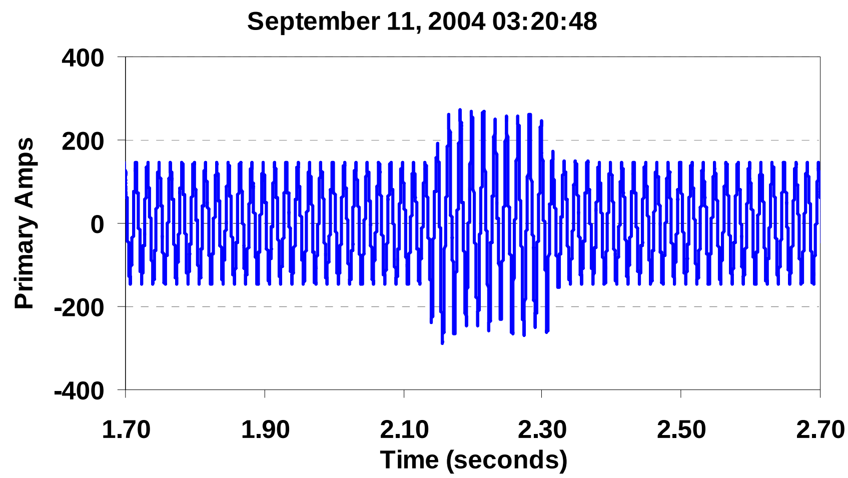
Participating utilities investigate and document the underlying causes of events of interest. This is most important, because it allows previously undocumented varieties of failures and fault precursors to be associated with the signals the DFA captures. Without this vital investigation and documentation component, significant numbers of anomalous signals remain unexplained and valuable potential knowledge is squandered.

Traditional fault recording systems typically are configured to record waveforms when high-current faults occur, while ignoring smaller signal variations. This is done to avoid being deluged with such a large amount of data that no one would ever have time to analyze it, which would effectively make all the data worthless, including the fault events of most interest. By contrast in the current effort, a conscious decision was made to capture waveforms when even small perturbations occurred. As noted, when the project began, there was little background knowledge about the types of precursor signals that many incipient failures would produce. Also, component failures are relatively rare. While this is good for all of us as customers, it presents a challenge in a project such as this one, in which the approach is to install monitoring equipment and then wait for something of interest to happen. Therefore, to minimize the chances of missing the highly important, infrequent event of true interest, the mechanism to trigger the storage of high-speed waveforms is intentionally set very sensitively. Therefore it records many normal system events, most notably capacitors switching and large motors starting. It has proven to be true that many fault precursors produce electrical signals of the same or smaller magnitude as these normal system events. Therefore, as expected, the vast majority of the captured waveforms represent "normal" system events, with only a small fraction representing events of interest.

These efforts have resulted in a massive database consisting of tens of thousands of captured event waveforms, which is a significant data management challenge. Only a small percentage of the captured waveforms represent events of interest. However, from this small fraction comes significant knowledge about a variety of failures and precursors. The remainder of this paper documents specific cases.

Case Study #1: Underground secondary cable failure

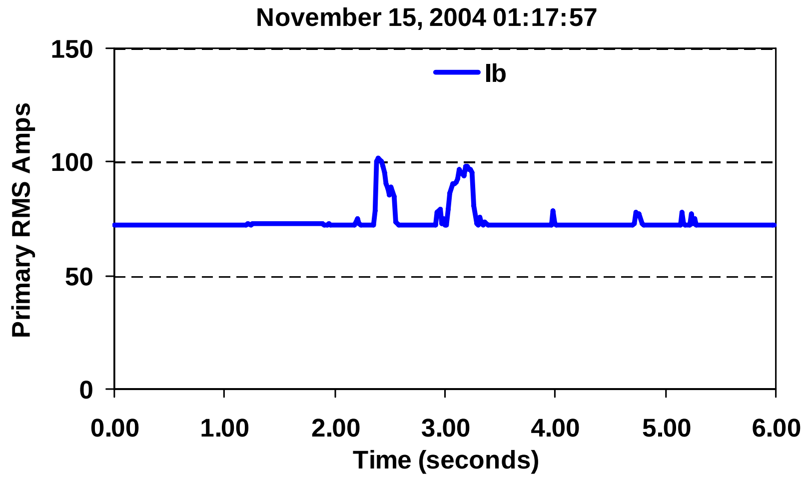
A DFA recorded several episodes similar to the current signal shown below in September 2004. DFA measurements are made from substation CTs and PTs, so the measured currents include normal load current plus any anomalous current that an event might generate. During the episode shown in the figure, the measured current increased by about 100 amperes peak (71 amps RMS equivalent) for eleven cycles. Detailed analysis of the waveform indicated that this was a temporary burst of arcing, not a motor starting or some other normal system event.



The utility received a lights-out call from customers at three residences served via low-voltage (i.e., 120/240VAC) underground cable that is fed from a 50 kVA CSP transformer on a nearby pole. A trouble crew responded and found that the transformer's breaker had tripped, but the crew found no obvious problem to account for the trip. The crew reset the breaker, verified normal voltages present at the customers' service entrances, and left with full service restored.

Over the next three months, this pattern recurred multiple times. Each time customers complained of lights out, a crew responded and reset the transformer breaker, but found no cause for the problem and left with service restored. In each episode the DFA recorded current similar to that shown above. Interestingly the DFA also measured numerous other similar episodes that did not result in lights-out calls. The next figure illustrates an episode in which the event did not trip the transformer breaker. It is presented as an RMS waveform because this format best illustrates the intermittent nature of the arcing current bursts. The two large bursts near the middle of the illustrated time period did not trip the transformer breaker, as demonstrated by the fact that smaller bursts of arcing current continued to occur later in the period.

The crews did not know of the events that the DFA was recording at the substation. Under normal conditions master stations at Texas A&M and at each utility company retrieve data from these substation units one or more times per day. Internet service to this substation failed in early September, however, and was not restored until November. When Internet service finally was restored, the backlog of event waveforms was retrieved from the substation device to the Master Station and it was apparent that something was wrong.



The utility patrolled the feeder for obvious sources of arcing current (e.g., tree limbs or broken poletop hardware), but did not find the cause. In early December the utility's engineer who was responsible for DFA matters had discussions with operating personnel and made them aware of the intermittent arcing signatures the DFA was recording on this feeder.

The customers whose transformer had been tripping called with another lights-out call early December 7, 2004. Having been alerted to the problem being reported by the DFA, the responding crew inquired as to whether the DFA had registered anything near the time this latest outage occurred. Upon learning that it had, they surmised that the problem likely was failing insulation on the direct-buried underground service cables to one or more of these customers' services. They strung temporary overhead services to these customers and then excavated the service cables when time allowed.

A section of the excavated cables appears in the photographs below. The left-hand photograph shows the two black "live" legs and the yellow neutral conductor. The right-hand photograph is a close-up view of the worst section of the bottommost conductor from the left-hand photograph. The insulation had deteriorated completely away in several obvious locations. What is most interesting in the right-hand photograph is that there were sections of cable up to an inch in length for which the entire conductor had corroded away, but these cables were still carrying load current, albeit with intermittent shorts and outages. The crew noted that there were multiple locations in the service cables that had damage similar to that shown in the photographs.

In summary this case documented an intermittent failure on underground secondary service cables, through primary current measurements made at the serving substation. Without information from the DFA, the utility had no clear guidance about the nature of the problem that was causing repetitive lights-out calls. The DFA provided them with clear and convincing evidence that there was an intermittent failure and allowed them to take appropriate corrective action. In addition it provided researchers with a significant number of "real-world" measurements over a three-month period, providing the basis for better determining the cause of similar failures in the future.


Case Study #2: Improper capacitor controller setting

In addition to recognizing electrical signatures that indicate the breakdown of insulation or some other failure process, the project documents examples of operational problems with line apparatus. One particular problem that has affected multiple utilities, multiple times, involves improper capacitor controller operations caused by improper settings or faulty controller hardware.

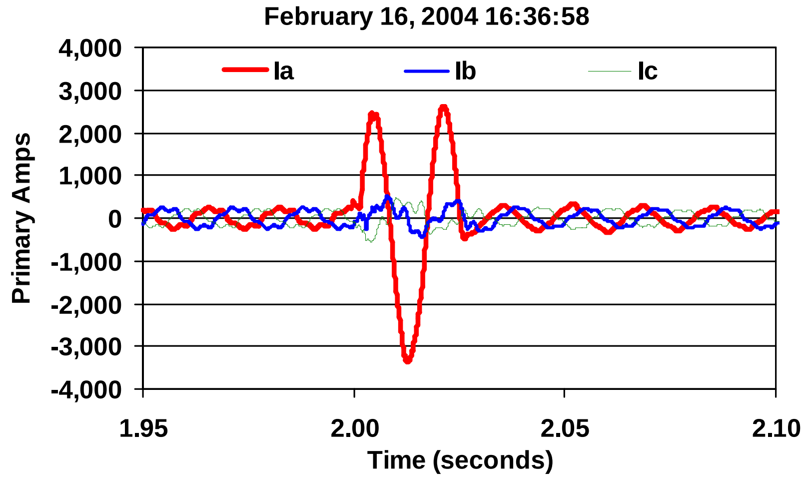
One of the DFA systems was installed and went online in a utility substation January 2004. Within a few days, it became obvious that the controller for a capacitor on one of the monitored feeders had an operational problem, because the bank was cycling ON and OFF far too frequently. Instead of cycling once or perhaps twice daily, this bank was switching dozens of times per day. Over time the frequency of operation increased. Listed below is a tabulation of daily switching operations for this bank for the first week of January 2004 and for the first week of February 2004.

Date	Switching Operations
01/01/2004	39
01/02/2004	28
01/03/2004	14
01/04/2004	27
01/05/2004	32
01/06/2004	71
01/07/2004	34
Week Total	245
	(35/day average)

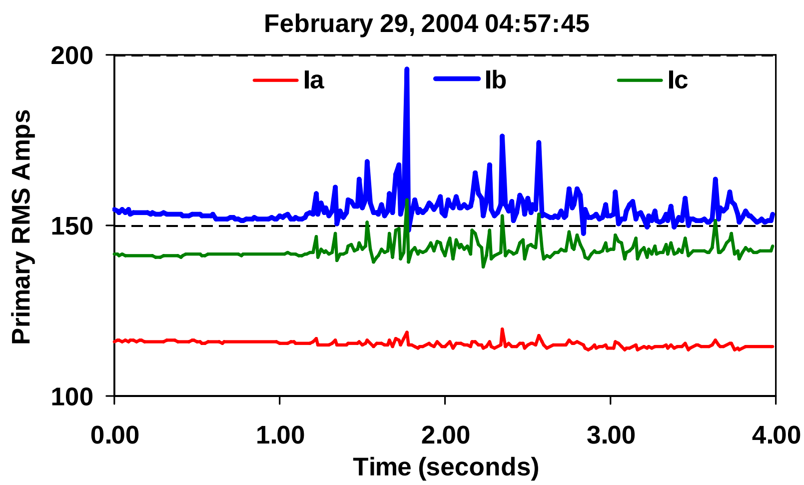
Date	Switching Operations
02/01/2004	12
02/02/2004	36
02/03/2004	78
02/04/2004	119
02/05/2004	77
02/06/2004	82
02/07/2004	90
Week Total	494
	(70/day average)

The utility at which this occurred uses the DFA system to document the natural progression of system events. If the utility identifies a problem through normal means (e.g., customer calls, normal maintenance cycles, etc.), they respond as they normally would. If the DFA is their only source of information about a problem, the utility monitors and documents its normal progression. This results in customers receiving the same level of service they would receive if the DFA were not present. This approach is quite beneficial to project's scientific objectives, allowing documentation of normal failure processes, sometimes for the first time ever.

By mid February this capacitor bank had switched several thousand times. On February 16, the phase-A capacitor failed and caused a short circuit, as illustrated in the following waveform. It is believed likely that the capacitor's failure was precipitated by the excessive switching operations and the associated transient stresses.

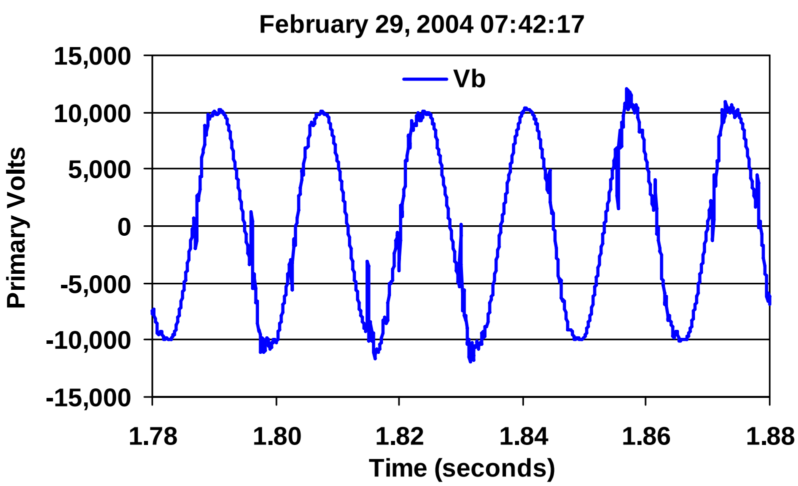


Following the failure of the phase-A capacitor, the controller continued to switch the bank's remaining two phases ON and OFF excessively. On February 29 the problem escalated further. After cycling ON and OFF repetitively in the early morning hours, the bank switched ON at 04:57:37. A few seconds later, the capacitor began to produce repetitive transients as the contacts in the oil switch for the phase-B capacitor began to arc internally. The thousands of switching operations over the past two months far exceeded the recommended maintenance cycle for this switch, and the switch's pitted contacts could no longer maintain proper electrical connection. The following RMS waveforms illustrate the erratic current caused by the intermittent connection in the capacitor switch's contacts.



Failure of oil-switch contacts is not a surprising phenomenon following several thousand operations. However, most engineers likely would assume that the contacts would destroy themselves completely within a relatively short time, perhaps a few seconds or minutes. In this case, however, the failing switch continued to conduct intermittently for four days before finally resulting in an open-circuit condition that effectively ended the problem. During this time the controller continued to cycle the bank ON and OFF repetitively. It was ON for a significant percentage of the time and continued to display erratic current when it was ON.

Each time a capacitor switches ON, it produces voltage transients that are seen along the feeder and at the bus. Because the transients appear at the bus, other feeders connected to that bus see the transient voltage as well. In the present case, the feeder with the failing capacitor switch shared a bus with one other feeder. The following figure shows the voltage distortion and transients present at the substation bus during one recorded interval. Because these signals were present at the bus, all loads and apparatus connected to both of this bus's feeders experienced their effects. The DFA recorded the significant transient currents that flowed in both of these feeders.



On the morning of March 1, about 28 hours after the switch began to fail, a capacitor on the other feeder connected to this bus short circuited and caused an overcurrent. The obvious conclusion is that the near-continuous coupled transients caused failure of this capacitor. In addition, over the four-day period of time during which the switch was failing, two other capacitors failed on the feeder with the faulty switch.

This case provided a great deal of valuable information. It is not surprising that the faulty controller behavior caused that bank's phase-A capacitor to fail. It also is not surprising that the excessive switching caused the oil switch to fail after several thousand operations. It is surprising, however, that the failing contacts continued to arc vigorously for four days. It also is surprising that the transients from this failing switch caused failures not just at the subject bank, but also at other banks on the feeder and even on a bank on another feeder connected to the same bus. Of note, during this project, another utility developed a contact failure in an oil switch on a capacitor bank, and the resulting continuous transients caused operation of a fuse on a capacitor bank elsewhere on the feeder.

Lest one think controller problems like this are rare, it should be noted that at least three participating utilities experienced problems with faulty capacitor controllers. The utility that had the problem detailed here developed a second problem in early 2006, in which a capacitor bank registered more than 250 operations in a single day. This time the utility decided to act on the DFA's information, because they felt that their experience in 2004 was sufficient to document the failure process. Also, the utility received a customer complaint in the 2006 episode, whereas they received no complaint during the 2004 episode.

Another participating utility experienced two dozen capacitor switching operations in a single afternoon, immediately after performing annual preventative maintenance on one of their banks. They visited the bank the next day and determined that an improper controller setting had been entered during the maintenance visit. This is an interesting case because it illustrates that preventative maintenance programs can be not only ineffective and inefficient but that they can even introduce problems into formerly properly operating apparatus.

A third utility company registered more than 3,000 switching operations of a single bank in a one-week period in early 2006. Based upon information from the DFA, they visited the offending capacitor bank, and found and fixed failed circuitry in its controller.

Summary and Conclusions

Electric utility companies face competing demands for high reliability and low-cost service. Utilities use time-based, preventative maintenance programs to maintain acceptable reliability. They use this brute-force approach because they do not have tools that allow them to maintain their systems in a more targeted way.

EPRI-sponsored research at Texas A&M seeks to identify precursors to failures of line apparatus and components. This research also identifies operational problems with line apparatus by using electrical signals available at the substation and on feeders. Proper use of the information being gained shows great potential for increasing electric utilities' knowledge of the health of their systems. This knowledge is key to operating these systems more reliably and more efficiently.

1. Michael Maquire, "Predictive Maintenance: What Does It Do?" *Electrical World*, vol. 206, no. 6, June 1992, pp. 11-12.

Carl L. Benner (M'1988, SM'2004) earned the B.S. and M.S. degrees in Electrical Engineering at Texas A&M University in 1986 and 1988.

Mr. Benner serves as Research Engineer and manages the activities of the Power System Automation Laboratory in the Department of Electrical 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 the application of microcomputer-based monitoring and control. Mr. Benner holds four patents in the area of high-impedance fault detection.

Mr. Benner is a member of the IEEE Power Engineering Society and Industry Applications Society. He is a registered Professional Engineer in the State of Texas.

B. Don Russell (Fellow'1991) is Regents Professor and J.W. Runyon Professor of Electrical Engineering at Texas A&M University. Dr. Russell is Director of the Power System Automation Laboratory. His research interests are in the application of advanced digital technologies to the solution of power system automation, control, and protection problems. Dr. Russell holds multiple patents in the area of digital protection, including high-impedance fault detection.

Dr. Russell is Past President of the Power Engineering Society (PES) and former director of IEEE. He is a Fellow of the National Society of Professional Engineers. He is a registered Professional Engineer in the State of Texas, Vice President of USNC CIGRE, and a member of the National Academy of Engineering.

Author Contact Information:
Carl L. Benner and Dr. B. Don Russell
Department of Electrical and Computer Engineering
Texas A&M University
College Station, TX 77843-3128
benner@ece.tamu.edu
979-845-6224