EPRI

Distribution Fault Anticipator

Technical Report

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Distribution Fault Anticipator

1001879

Final Report, December 2001

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This report describes research sponsored by EPRI.

The report is a corporate document that should be cited in the literature in the following manner:

Distribution Fault Anticipator, EPRI, Palo Alto, CA: 2001. 1001879.

REPORT SUMMARY

Background

Deregulation and competition are relatively new ideas for the electric utility industry. Utility companies now must deal with competitive forces that compel them both to reevaluate high-cost practices and to provide better service to their customers. Preventive, time-based maintenance of the distribution system is one such high-cost practice. It is tempting to reduce such maintenance drastically but doing so in a capricious manner can reduce reliability and power quality. The new, competitive environment does not allow this.

EPRI has been involved for decades with research at Texas A&M University in the characterization and detection of arcing phenomena on distribution feeders. This project was based on the assumption that failing equipment would exhibit arcing and sparking well in advance of full-blown failures. If such activity could be recognized, on-line monitoring could anticipate faults and warn utilities before progressively deteriorating conditions caused overcurrent faults and the operation of conventional protection. This would allow utility companies to reduce preventive maintenance and replace it with condition-based maintenance, thereby targeting available resources in order to maintain high service quality while reducing costs.

Objectives

The project objective was to demonstrate that incipient fault conditions produce detectable signals, thereby validating the concept of using on-line monitoring to detect them. This would enable utilities to anticipate faults, allocate resources and make repairs before the faults actually occur and cause service disruptions. Such fault-anticipation technology would allow utility companies to maintain or even improve service quality and reliability while significantly reducing costs.

Approach

This project consisted of two distinct stages. In the first stage, short- and long-term experiments confirmed that contaminated, damaged distribution equipment produces measurable changes in electrical parameters. This validated the fundamental underlying premise of the project.

The second stage consisted of designing and constructing a small number of pre-prototype data collection systems and installing them on distribution feeders for an extended period of time (i.e., one to two years). During this time, research personnel regularly retrieved data from these systems and, when signal anomalies occurred, worked with the host utilities to determine the underlying causes.

Results

The first stage of the project successfully demonstrated that simulated incipient faults (i.e., contaminated, damaged insulators) indeed do produce measurable parametric changes. These experiments also provided an initial estimate of the magnitude of some of the signals accompanying such conditions.

The second stage of the project was truly exciting in that it resulted in the detection and capture of multiple non-staged incipient faults. With the help of the host utilities, personnel were able to correlate anomalous captured data with events on the power systems. Examples included the detection of a failing lightning arrestor, significant parametric changes corresponding to tree trimming, and incipient conditions that caused numerous, intermittent overcurrent faults of which the host utilities were otherwise unaware.

EPRI Perspective

Imagine what a system operator could do if he had information that a device on a distribution feeder was going to fail in the next several hours, days, or weeks, or that tree contact with overhead lines was about to become a problem. Now imagine that this information could be provided to the operator in advance of a failure actually occurring, that is, before any overcurrent occurred or protective device operated.

Research underway shows great promise for providing the distribution system operator with just this type of information. Researchers have developed signal-processing techniques that separate low-level signal components from the dominant 60-Hertz load, thereby allowing the detection of incipient fault conditions. The work described in this report illustrates several examples of measured parametric changes that resulted from tree encroachment, equipment failure, etc.

This development holds enormous potential for electric power distribution systems. Service reliability improvements are possible by anticipating faults and making preemptive repairs. In addition, maintenance cost reductions are possible, without negative effects on reliability, by targeting available resources to those feeders that truly need maintenance.

Keywords

Incipient faults
Fault anticipation
Conditioned-based maintenance
Distribution feeder maintenance
On-line monitoring
Electric utility deregulation

ABSTRACT

Today's competitive environment makes two demands of electric utility companies: that they provide better service and that they do so at lower cost. Unfortunately, conventional methods of improving service tend to increase costs. Conversely, some methods of lowering costs tend to reduce service quality.

The ubiquity of electronic and computer-based loads makes even momentary service perturbations and interruptions intolerable. Customers may be somewhat forgiving of occasional problems during stormy weather but they expect near-perfect service during fair weather.

Maintenance budgets are attractive targets for cost reductions because they are very large and because it is difficult to quantify their benefits precisely. Historically, distribution feeder maintenance consisted in large part of calendar-based activities such as right-of-way tree trimming, patrols and inspections, and other periodic programs. By their nature, such practices are wasteful because they focus much cost and attention on perfectly healthy components. However, utility companies currently lack the tools that would enable them to better focus their maintenance resources where they are needed. Therefore, either they must maintain everything, which is inefficient, or blindly reduce maintenance and risk severe degradation of service.

The goal of this project was to investigate the use of on-line monitoring to detect incipient faults on distribution feeders. This would provide utility companies with tools to "anticipate" faults and take corrective action before disruptive faults developed and affected customers. In addition, utilities would be able to focus limited maintenance resources where they were most needed, thereby replacing time-based maintenance with more efficient condition-based practices. This would reduce costs significantly while maintaining or even improving service quality.

Researchers at Texas A&M University (TAMU) have investigated arcing phenomena for decades. They believed that incipient faults would produce arcing and sparking, which in turn would produce measurable changes in electrical parameters. Initial stages of this project experimentally confirmed this. Later stages consisted of designing a pre-prototype data collection system and constructing and installing such systems on operating feeders for an extended period of time. Data from these installations further confirmed measurable parametric changes during the early stages of incipient faults.

Based upon the success of this proof-of-concept phase, TAMU and EPRI envision advancing to the next phase. They anticipate designing an enhanced prototype platform and installing copies of it on significantly more feeders. This coming phase will allow them to collect a much larger number of incipient cases, educate utility personnel about the technology, and automate the recognition of incipient fault signatures, with the ultimate goal of providing fault anticipation.

ACKNOWLEDGMENTS

Much of the work performed under this project would not have been possible without the dedicated support and assistance of a number of individuals. EPRI and Texas A&M University wish to acknowledge their efforts.

Mr. James Fangue (TXU Electric) championed this project both from its inception and continually throughout its duration. In addition, the following individuals participated faithfully in advisory meetings over the course of the project:

Mr. James Fangue, TXU Electric
Mr. Don Boyd, Southern Company
Mr. Robert Jones, Rochester Gas and Electric
Mr. Wayne Gallimore, Northern Indiana Public Service Company

Finally, on the "front lines" were the utility personnel who assisted in the diagnosis and location of field events that were recorded over the course of the project:

Mr. Alan Wilkerson, TXU Electric
Mr. Joe Greenwell, TXU Electric
Mr. Chris Boggio, Rochester Gas and Electric
Mr. Grady Smith, Southern Company

EPRI and Texas A&M gratefully acknowledge the efforts and contributions of each these individuals.

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1
SUMMARY

Many interrelated factors are reshaping the electric utility business, driving utility companies to provide better service and to do so more efficiently. Customers, particularly those with sensitive electronic loads, demand better reliability and quality. At the same time, competitive forces require that utility companies eliminate wasteful practices in order to survive.

The causes of outages fall into two broad categories: precipitous faults and incipient faults. Precipitous faults are those that provide no early warning whatsoever that they are about to happen and include such things as cars hitting poles. Incipient faults, on the other hand, may provide early indication of their existence, sometimes days or weeks in advance of any activity that customers would recognize as degrading their service. Examples of incipient faults include tree contact with overhead primary conductors and contamination buildup on insulators.

The fact that incipient faults produce early warning signs implies the potential to "anticipate" such faults during these early stages, before they affect customers. A system or method to anticipate faults would be invaluable to utility companies in that it would allow them to have advance warning of impending failures. This would allow them to schedule repairs before customers experience any adverse consequences such as voltage sags, outages, etc. If such fault anticipation technology were available, it would allow utilities to address both better quality and lower operating costs and to do so simultaneously.

Texas A&M University (TAMU) researchers have investigated techniques for monitoring and controlling electric power systems for more than two decades. Their most notable achievement was under previous EPRI sponsorship and involved the development of practical techniques for detecting arcing faults. Their past effort is relevant to the topic at hand because it seemed likely that incipient faults would exhibit similar arcing behavior. If this activity could be detected, it would provide the foundation for anticipating faults.

In the early stages of this project, a series of experiments with artificially contaminated and damaged distribution system components confirmed the fundamental premise that incipient faults exhibit characteristics similar to those of downed-conductor arcing faults. This validated the project's fundamental hypothesis: that incipient faults produce measurable electrical changes that are indicative of progressively deteriorating conditions, and that these signals provide the basis for an early warning system that utilities could use to anticipate faults and schedule repairs, thereby avoiding outages and enhancing service reliability and quality.

Based upon the encouraging results of these experiments, the next stage of the project concentrated on the design, construction, deployment and monitoring of a small number of

pre-prototype data collection systems. Researchers installed four of these pre-prototype systems at utility substations and monitored them remotely for an average period of more than a year.

The pre-prototypes captured data from numerous faults and other events. In addition to classical faults and events, they detected and recorded multiple unusual incipient-type events. In these cases, TAMU research personnel requested and received help from the host utilities to determine the underlying causes of the events. By matching measurements with confirmed power system events, they were able to create a library containing measurements of multiple types of incipient faults.

The results to date have been encouraging and even exciting and EPRI and TAMU currently are planning the next phase in this fault anticipation effort. Plans for this next phase are not yet final, but it is anticipated that they will involve developing a prototype system that will overcome several shortcomings and limitations of the pre-prototype data collection systems. Each prototype will be capable of monitoring multiple feeders in a given substation, in contrast with the pre-prototypes' limitation of one feeder per pre-prototype. In addition, the number of participating utilities is anticipated to be significantly greater. Overall, it is anticipated that these prototypes will monitor several dozen feeders on ten or more utilities' system.

This greatly increased installation base should facilitate significant expansion of the number and types of incipient faults currently in the database. In addition, a further goal of the next phase will be to automate the currently manual process of recognizing incipient faults. Finally, the next phase will involve greater day-to-day utility involvement, which has the dual benefits of providing better correlation between measured events and their power system causes and of educating utility personnel better about the technology.

2
INTRODUCTION AND JUSTIFICATION

Background Motivation

Customers have high expectations regarding the quality and reliability of service that electric utility companies deliver. They are somewhat forgiving of occasional blinks and outages during bad weather but during fair weather, they have one simple but demanding expectation: keep the lights on!

To some customers, unexpected service disruptions are merely annoying. They must reset digital clocks, miss favorite television programs, etc. However, other customers suffer significant economic losses whenever disruptions occur. A study by Duke Power that attempted to quantify these costs found the following costs associated with power disturbances for large commercial and industrial customers[1]:

One- to two-second outage	$11,000
Fifteen-cycle voltage sage (10-20%)	$7,700

Whether interruptions are simply annoyances or they represent an economic loss, customers are decidedly unhappy when their electric service does not meet their expectations. It is interesting that another report, this one by National Economic Research Associates, Inc., found that "in all cases, … customers were bothered more by the outage itself than by the loss of electricity."[2]

Service disruptions have many distinct causes, but at the distribution level most fall into two general categories. In the first category are precipitous events such as cars hitting poles. By their very nature, these faults give no advance warning. The other category includes causes that may develop over long periods of time (e.g., days, weeks or months) such as deteriorating equipment, contamination, and encroachment of foreign objects. Examples include cracked insulators and bushings, stressed lightning arrestors, and tree contact. These faults are referred to as incipient faults and, during the early stages of their development, they often pose little threat to the integrity and reliability of the electric power system. Over time, however, the severity of incipient faults can evolve to the point that they cause momentary interruptions or even sustained unplanned outages. Obviously, it is to the utility company's benefit to be able to anticipate such faults and cure them before they escalate and cause customer problems.

Historically, utilities have mitigated problems from degrading conditions through intensive preventive maintenance programs, including right-of-way tree trimming, patrols and inspections, and other periodic programs. Unfortunately, these periodic maintenance activities are very expensive. Further, utilities must set the frequency of maintenance cycles conservatively in order

to be truly effective. In other words, they must set their maintenance intervals short enough to prevent the operation of their worst-performing feeders from becoming unacceptable.

Conservative maintenance intervals necessarily mean that much of the maintenance and testing is performed on equipment that is perfectly healthy, particularly on those feeders that are relatively well behaved. A 1992 study that examined maintenance costs for American industry as a whole gives an idea of the magnitude of costs involved by concluding that "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 unnecessarily squandered and represent a loss of over $66-billion."[3] Simply stated, the amount wasted, and therefore the potential for savings, is enormous.

In recent years, electric utility deregulation has been a topic of much discussion, both within the industry itself and among the general media and public. Deregulation introduces competitive forces into an industry that historically has operated as a collection of regulated geographic monopolies. One effect of competition is that expenses that previously simply had to meet requirements for regulatory approval now also must be justified with respect to their effect on the bottom line.

When budgets tighten, maintenance dollars are attractive targets for deep cuts. Unfortunately, capriciously reducing or eliminating maintenance is certain to have deleterious effects on the ability of the system to deliver service at a level that meets customers' expectations.

Obviously, utility companies need alternatives that enable them to provide reliable, high-quality service while reducing unnecessary expenses. Such alternatives should allow them to reduce or eliminate activities that do not produce beneficial results while targeting resources where they can do the most good. To this end, this project's goal is to investigate the potential for anticipating faults by detecting parametric changes that provide early warning signs of incipient faults. Such a fault anticipation system would allow utility companies to make preemptive repairs and avoid interruptions and outages, all without the overwhelming and inefficient expense of conservative, calendar-based, preventive maintenance cycles.

Foundational Work and Hypothesis

Researchers at Texas A&M University have performed decades of research in the area of high-impedance fault detection, much of it on the behalf of EPRI[4]. They extensively characterized high-impedance faults, which by definition are those faults that do not produce enough current to cause conventional overcurrent protection to operate. One feature of many high-impedance faults is arcing. Researchers exhaustively characterized arcing and developed techniques for its detection. They subsequently patented these techniques and licensed them to an established manufacturing partner that makes this technology available to utility companies in the form of commercial devices.

At the outset of this present project, researchers hypothesized that failing equipment on electricity distribution feeders would cause arcing and sparking well in advance of faults that would be noticeable to customers or that would cause them concern. They further hypothesized

that this arcing and sparking would result in measurable changes in electrical parameters that would be similar to the changes that arcing downed conductors exhibited.

Accordingly, the initial months of the project focussed on experimentally determining whether arcing accompanied incipient faults and, if it did, on obtaining initial estimates of the magnitude and characteristics of that arcing. This experimental work confirmed the presence of arcing, so researchers proceeded to the next stage of the project, in which they designed, developed and deployed a limited number of pre-prototype data collection systems that gathered field data from operating feeders over an extended period of time. These systems detected and recorded multiple instances of incipient faults, further validating the concept of using on-line monitoring for fault anticipation.

3
EXPERIMENTAL VALIDATION

The project's fundamental hypothesis was that failing equipment would cause measurable electrical activity to take place. The initial work on this project consisted of experimentally confirming this. Through a series of experiments, Texas A&M University (TAMU) researchers measured the electrical activity that occurred when they subjected contaminated or damaged line hardware to nominal distribution voltage. This chapter summarizes the experimental methods and their results.

Experimental Facility

During their work on downed-conductor fault detection, TAMU researchers established a facility near their main campus in College Station, Texas, for conducting experiments on an operating distribution feeder. The facility receives its electric service from an operating feeder that also serves the surrounding community. The feeder is of standard overhead construction and operates in a multi-grounded wye configuration. The nominal line voltage is 12.47 kV and the nominal load on the circuit varies from about two to four megawatts. The facility is located just over one electrical mile from the substation and the available single-line-to-ground fault current is approximately 2,200 amperes. The facility itself consists of a series of poles and switches that allow access to and control of the overhead service. At the facility there are conventional current and potential transformers (i.e., CTs and PTs) for monitoring experiments. In addition, the facility has an instrumentation building that houses temporary and semi-permanent equipment installations on an as-needed basis.

The utility company that provides service to the facility has no control house at its substation, so researchers constructed a small instrumentation building there. Inside that building, the utility company makes access available to the secondary connections of the CTs and PTs that they use for metering their distribution bus. The building provides air-conditioned housing for equipment installations.

Initial Insulator Experiments

The initial experiments under this project consisted of subjecting contaminated and/or damaged pin-type porcelain insulators to nominal system voltage. Early in the process, the experiments showed that even heavily contaminated, badly damaged dry insulators were capable of supporting nominal voltage, apparently as well as clean undamaged ones. However, they showed significantly different performance when moisture was present.

For these first experiments, researchers connected several (e.g., five) contaminated insulators between one of the power system's 7,200-volt phase conductors and ground. They sprayed the insulators with a water-based solution of kaolin and salt and evacuated the area, after which linemen closed a fused cutout to energize the circuit and begin the experiment.

The insulators immediately began producing visible and audible signs of arcing and sparking. However, the heat of the arcing and sparking combined with natural atmospheric forces to dry the surfaces of the insulators rather quickly. As this happened, the audible and visible activity diminished rapidly. After a period of one to two minutes, the activity stopped altogether.

Researchers found that if they sprayed the insulators with water again and then energized them again, the electrical activity began anew but again died away within a short period of time. This made obvious the fact that moisture was a key ingredient in contamination-related incipient activity. The research team therefore set about to devise and conduct additional experiments that included means for wetting the insulators continuously.

Fog-chamber Experiments

In order to simulate a continuous wetting environment, researchers constructed a crude fog-chamber apparatus that allowed wetting of the energized insulators at a steady, continuous rate. This allowed them to conduct sustained experiments, which showed that the arcing and sparking activity generally persisted for significant periods of time, provided that there was a steady supply of moisture. As this period of time went on, the artificial wetting tended to wash the contaminant from the surface of the insulators. In turn, this caused the electrical activity to diminish over periods of multiple minutes to tens of minutes.

For these experiments, personnel contaminated multiple (e.g., fifteen) porcelain pin-type insulators with a solution of kaolin, salt and water and mounted them inside the chamber. They connected one conductor to the saddle groove of each insulator using standard tie wires and connected a second conductor to the metal support pins of all the insulators. They then connected the groove conductor to one phase of the distribution feeder that feeds the test facility and the pin conductor to the feeder's grounded neutral conductor. After physically closing the chamber enclosure, personnel started a pump that fed multiple misting nozzles inside the chamber, evacuated the area, and energized the insulators by closing a fused disconnect switch. This energized all fifteen insulators in parallel with each other at the power system's nominal 7,200-volt phase-to-ground voltage. Figure 3-1 shows a simplified schematic of the components and their interconnection.

As the figure shows, there was a 500-ohm current-limiting resistor network and a two-ohm monitor resistor in the return path (i.e., in the path between the insulator pins and the system neutral conductor). The monitor resistor provided simple means for recording a high-quality voltage signal that was proportional to the current flowing across the surface of the parallel insulators. The purpose of the current-limiting resistor was to protect the power system from a voltage dip if a high-current flashover should occur. The purpose of the two-amp fuse was to limit the amount of resistive heating the current-limiting resistor would experience in such a flashover.

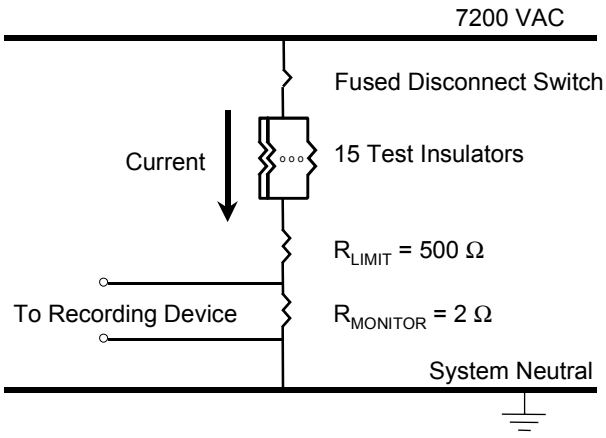


Figure 3-1
Schematic for Fog-chamber Experiments

Obviously, one must consider how the insertion of the 500-ohm current-limiting resistor might affect the experiment and its results. However, the pre-fog-chamber experiments suggested that the expected current levels would be in the range of tens of milliamps. If one considers a 100-milliamp current flow, the current-limiting resistor would drop the voltage across the insulators by 50 volts. This represents only 0.7 percent of the nominal system voltage of 7,200 volts and is far less than normal day-to-day variations. Therefore, researchers determined that the effect of the current-limiting resistance would be negligible.

Figure 3-2 shows two seconds of a current waveform from a typical fog-chamber experiment. The measured current consists of two superimposed components. First, there is a steady-state component whose magnitude is approximately four milliamps RMS. In addition, there are aperiodic bursts of significantly greater magnitude. The duration of these bursts generally ranges from one-half of one cycle to several tens of cycles, with those shown in the figure ranging from one to five cycles.

Figure 3-3 shows an expanded view of another such burst of current. The lower trace in the figure shows the shape of the overall current waveform and the upper trace shows the high-frequency current during this burst. These waveforms illustrate several characteristics of arcing that are quite similar to the characteristics that researchers previously had observed during their downed-conductor arcing-fault research. A later section in this chapter, entitled "Discussion of Arc Characteristics," discusses the mechanisms and characteristics of arc formation and how they relate to the behavior illustrated in Figure 3-3.

Finally, Figure 3-4 illustrates the calculated RMS of the measured high-frequency current components during another fog-chamber experiment. It illustrates the burst nature of this high-frequency current. It also illustrates that activity occurs for extended periods of time, as long as the continuous wetting mechanism is in place.

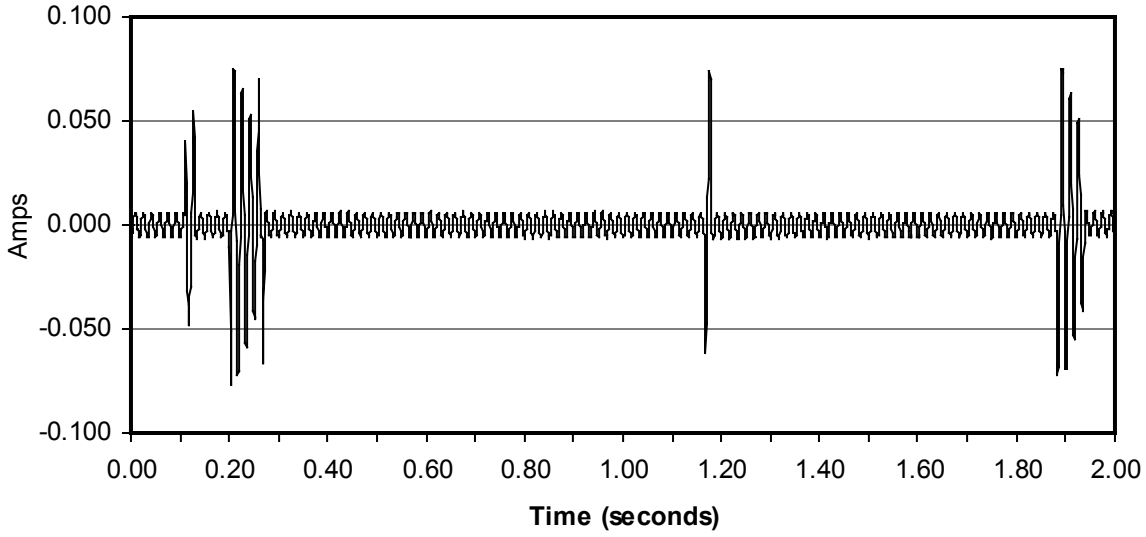


Figure 3-2
Current During Fog-chamber Experiment

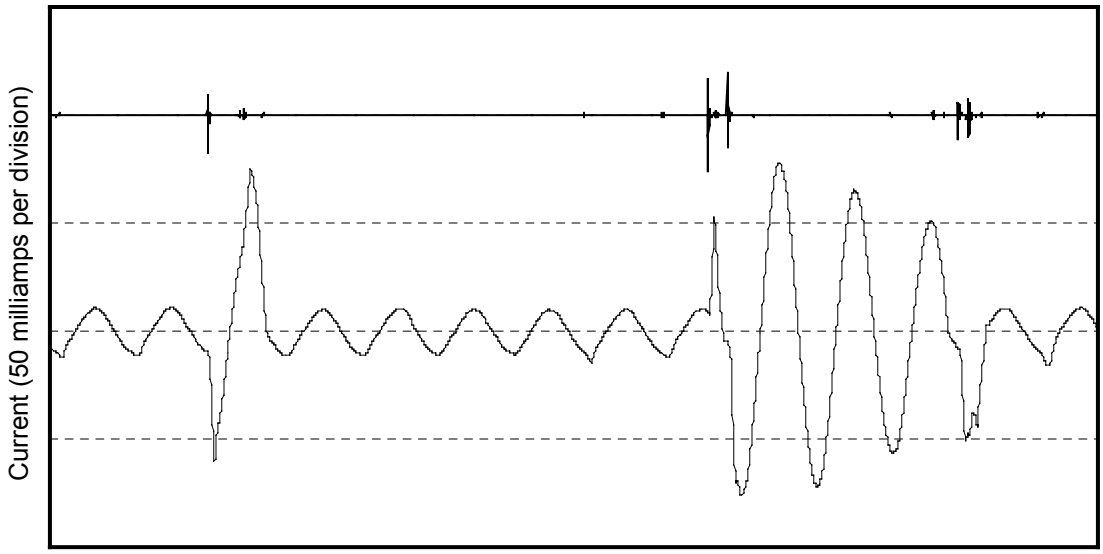


Figure 3-3
Current and High-frequency Current During Fog-chamber Experiment

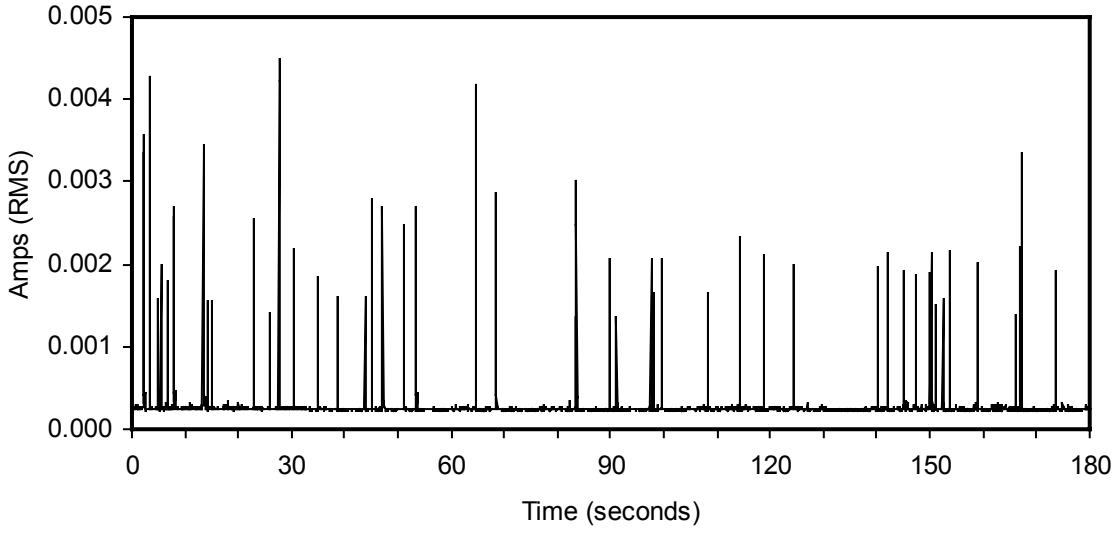


Figure 3-4
Three Minutes of High-frequency Current During Fog-chamber Experiment

Discussion of Arc Characteristics

Over a period of more than two decades, Texas A&M University researchers have performed extensive research in the characterization and detection of high-impedance arcing faults on distribution feeders. Based upon this experience, it was immediately obvious that the signals they obtained from the insulator experiments exhibited many familiar characteristics of arcing. A brief discussion of arc formation and the resulting characteristics is in order.

An arc occurs when the voltage gradient across an air gap becomes too great and current begins to flow. In an AC power system, this happens as the system voltage waveform increases toward its periodic peak. At first, the current consists of sparks of very small magnitude, on the order of milliamps or less. However, this small current flow begins to ionize air molecules in the gap and this ionization process greatly diminishes the dielectric strength of the air. Also, at the same time that the sparks are causing the gap's dielectric strength to decrease, the power system's voltage is continuing to increase toward its periodic peak, further increasing the voltage gradient across the gap.

The confluence of these factors leads to escalation of the current flow through the air gap, which in turn further ionizes more of the air in the gap. Once this avalanche process has produced sufficient ionization, the air in the gap offers little electrical resistance and arc current begins to flow in earnest. Because the air in the gap is now ionized, current flow through the gap can continue past the point at which the instantaneous voltage drops below the initial current-inception level.

The arc-initiation process in which individual sparks begin to jump the air gap evidences itself as relatively high-frequency current components. Interestingly, once the arc is well established, the high-frequency components are minimal. Then, as the voltage across the gap decreases, it

eventually reaches a level at which it can no longer support continued arc current. When this occurs, conduction through the gap becomes more difficult and finally fails. The result is that there is a second burst of high-frequency current near the point of extinction. Typically, the high-frequency activity associated with arc extinction is far less prominent than that associated with arc initiation but still significant nonetheless.

Wet, contaminated insulators represent a special case of arcing. Instead of a more conventional air gap, an arc forms when a dry band develops on an insulator's surface. In this case, most of the contaminated insulator's surface is wet and acts as a relatively linear resistance. However, if a dry band forms it interrupts the continuity of this continuous resistive path. When this occurs, the entire applied voltage appears across the relatively short physical distance across the dry band. This establishes an arc-gap condition similar to that of a conventional air gap and arc formation takes place in accordance with the preceding discussion.

Figure 3-3 illustrates the arc process in action. The figure does not show the applied voltage explicitly. However, the pre-arc current is highly resistive and largely in phase with the applied voltage. Therefore, referencing phase angles and peaks to the pre-arc current is roughly equivalent to referencing them to the applied voltage.

Figure 3-3 shows two distinct arc bursts, each beginning near peak system voltage and extinguishing near a voltage zero crossing. Note that extinction does not necessarily occur each half cycle but that conduction can continue for several cycles. The lower trace in the figure illustrates the severe distortion that accompanies arc initiation and extinction. It also shows that during an established arc burst, the distortion is much less noticeable.

The upper trace of Figure 3-3 shows the high-frequency current components for the same time period. It shows that significant high-frequency activity accompanies each instance of arc initiation. It also shows that a second significant high-frequency burst occurs coincident with the extinction of each arc burst, although at a smaller magnitude than the corresponding initiation burst. Finally, it illustrates that the high-frequency current components are minimal during established arc bursts, showing little or no difference from the pre-arc period.

The researchers found these characteristics to be very similar to the familiar characteristics of arcing, downed-conductor faults. Therefore, the fog-chamber experiments confirmed the original hypothesis, namely, that incipient faults cause arcing and sparking, which in turn produce measurable electrical evidence of their existence, and that the these signals are very similar to other types of arcing.

Long-term Experiments

The fog-chamber experiments provided validation that contaminated, damaged insulators produce measurable electrical activity, but that they do so only when sufficient moisture is present. Obviously, the continuous misting conditions of a fog chamber provided only a first-order approximation of actual operating conditions. The degree to which the wetting mechanism represented in-service wetting was unknown. In-service insulators typically do not experience continuous wetting. Rather, they more often experience cyclical wetting and drying

patterns. Atmospheric factors such as temperature, humidity, wind, and solar radiation greatly influence these cycles. Therefore, researchers designed and conducted a third type of experiment, this one a long-term experiment to determine the performance of contaminated and damaged insulators as they experience natural wetting and drying cycles.

Texas A&M's test facility provides an instrumentation platform on which researchers have mounted various current and potential transformers. This platform is elevated on standard line poles that keep it out of reach of passers-by, making it appropriate for this type of unattended long-term experiment. Personnel mounted porcelain pin-type distribution insulators atop this platform for long-term monitoring. They anticipated that the electrical performance both of contaminated insulators and of clean insulators would vary to some extent as a function of atmospheric conditions. Therefore, they installed two sets of insulators, one set contaminated and damaged and the other set clean and mechanically sound. The following paragraphs and figures refer to the contaminated and damaged insulators as "test insulators" and to the clean, sound insulators as "control insulators."

The set of test insulators consisted of 45 new porcelain, pin-type insulators. Personnel contaminated these insulators by coating them with a mixture of kaolin, salt and water. They also damaged twenty percent (i.e., nine) of the insulators by striking them with a hammer, causing part or all of their skirts to break off. Using standard tie wires and techniques, personnel wired all of the test insulators' saddle grooves together, creating a high-side terminal. They also connected all of the test insulators' pins together with a second conductor, creating a return terminal. They then connected the return terminal to the power system neutral via a 500-ohm current-limiting resistor network and connected the high-side terminal to one of the system's 7,200-volt phase conductors via a fused cutout containing a two-amp fuse. The reason for selecting these particular values was discussed in the preceding discussion about the fog-chamber experiments, so it is not repeated here.

The set of control insulators consisted of 45 insulators that were identical to the test insulators, except of course that they were not damaged or contaminated. Personnel wired them together just as they had done the test insulators and connected them to the system phase and neutral conductors in parallel with the set of test insulators.

Researchers instrumented each set of insulators so as to measure and record the voltage and the currents. They connected both sets of insulators to the same phase voltage, thereby ensuring that the control insulators saw the same source voltage that the test insulators saw. Therefore, only one voltage measurement was needed. They used two donut-type Pearson current transducers to measure the current flowing across the insulators, one to measure the current flow of the test insulators and one to measure the current flow of the control insulators. They positioned one of these transducers in the return path of each set of insulators, between the current-limiting resistor network and the connection to the system neutral. Figure 3-5 shows the experimental configuration.

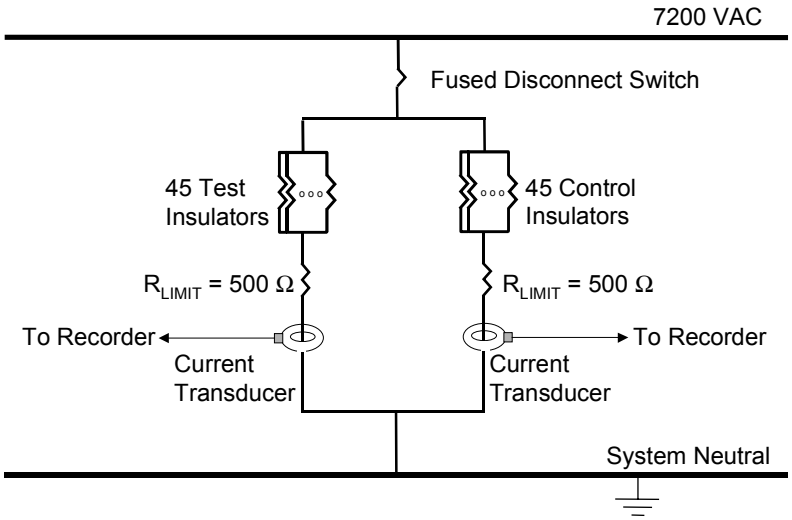


Figure 3-5
Configuration for Long-term Insulator Experiment

Personnel mounted both sets of insulators on the instrumentation platform at the test facility, closed the fused cutout to energize the experiment, and left it in this state for a period of several months. Over this period of time, they recorded the average current levels every fifteen minutes. They also recorded the average high-frequency current levels at the same interval. In addition, they monitored each current continuously and recorded high-speed waveforms for several seconds whenever they detected a sudden change in either. The following series of figures illustrates the behavior of the average currents over time and shows several of the high-speed waveform captures.

Figure 3-6 shows the relative humidity and the average current of the test insulators over a one-week period. It shows that there was a minimum current level of between three and four milliamps, even during periods of low humidity. It further shows that this level was almost constant for all humidity values below approximately 55 to 60 percent. At relative humidity levels above about 60 percent, however, the insulator current increased dramatically. Above this humidity level, it is obvious that there was a strong correlation between the humidity level and the current level.

Figure 3-7 shows the relative humidity and the average current of the control insulators over the same one-week period. There was a stark contrast between these insulators' current and that of the test insulators. The control insulators showed approximately the same base level of three to four milliamps during periods of low humidity. However, the control insulators' current remained at this level until the humidity was much higher, in excess of 80 percent. During periods of very high humidity, the control insulators' current did increase noticeably, but even under these conditions the increase was only about one milliamp. By contrast, the test insulators' current increased by up to fourteen milliamps during these same high-humidity periods.

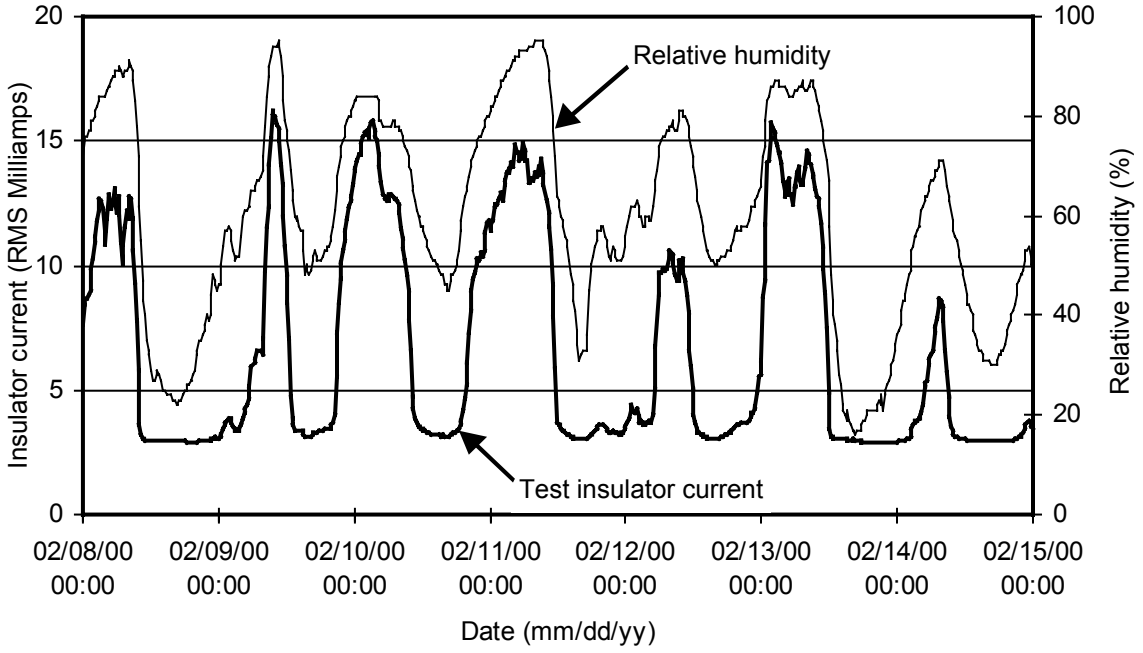


Figure 3-6
Diurnal Variation of Test Insulator Current vs. Humidity

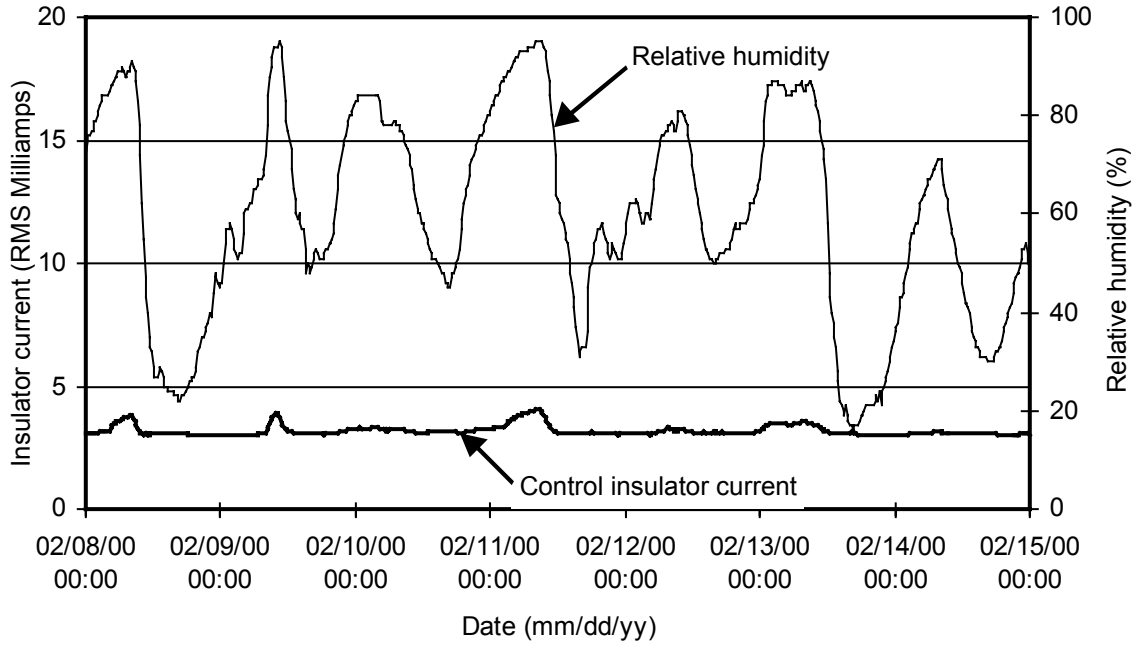


Figure 3-7
Diurnal Variation of Control Insulator Current vs. Humidity

Figure 3-8 shows a high-speed waveform snapshot during a period of low relative humidity. It shows the current waveforms both for the test insulators and for the control insulators. The most notable observation from this waveform capture is that there was no appreciable difference between the test insulators' current and the control insulators' current. In fact, the two were practically indistinguishable.

Figure 3-9 illustrates the high-frequency currents corresponding to the same low-humidity time period as Figure 3-8. Again, there was very little difference between the signal from the test insulators and that from the control insulators.

By contrast, Figure 3-10 illustrates the current measurements from the two sets of insulators during a period of high relative humidity. As shown, the test insulators' current was three to four times as large as the control insulators' current under these conditions. This illustrates that moisture from the atmosphere combined with the contaminant on the insulators' surfaces to enable a greater amount of steady-state, resistive current to flow across the surface of the insulators.

Finally, Figure 3-11 shows the high-frequency current measurements from the two sets of insulators during the high-humidity interval corresponding to Figure 3-10. Here the difference was most dramatic. The high-frequency current of the control insulators was little different than it was during low-humidity conditions. The high-frequency current of the test insulators, on the other hand, increased by more than an order of magnitude. The periodic nature of the high-frequency bursts also was quite apparent. During the time interval that this figure represents, there were 30 distinct bursts of high-frequency current activity, corresponding directly to the fifteen cycles of fundamental-frequency current in Figure 3-10.

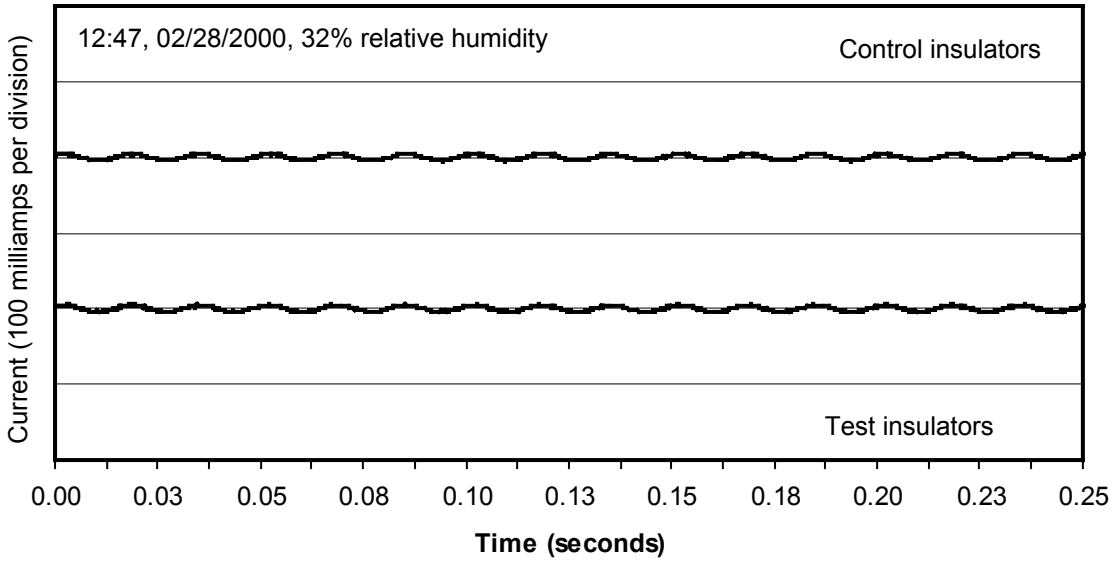


Figure 3-8
Current of Test and Control Insulators at Low Humidity

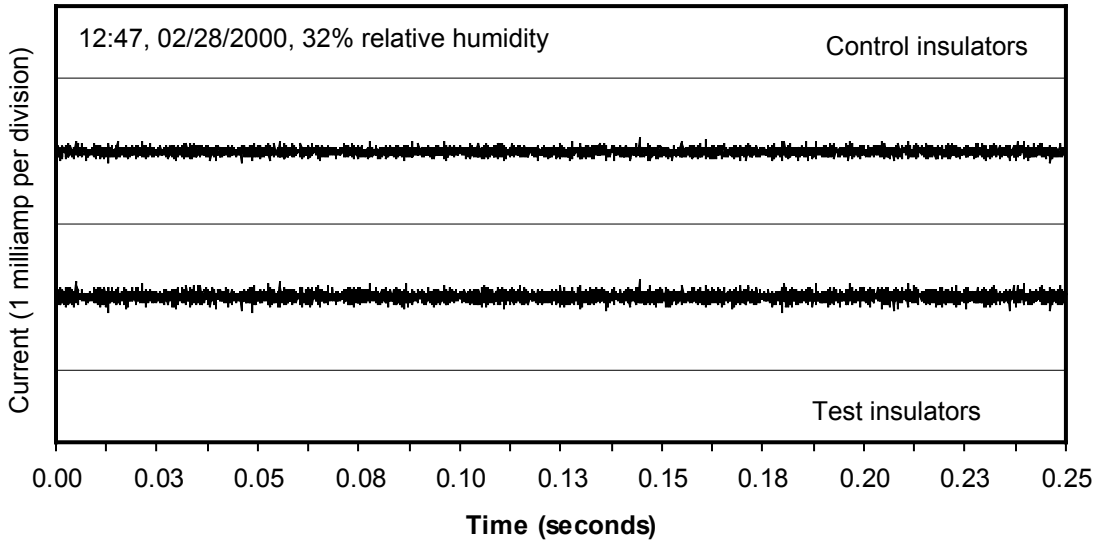


Figure 3-9
High-frequency Current of Test and Control Insulators at Low Humidity

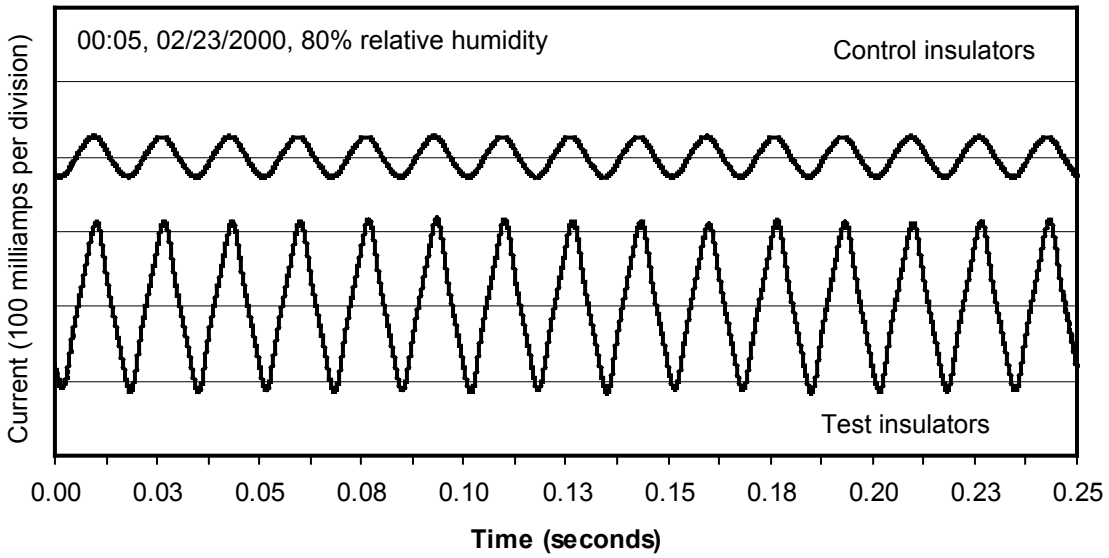


Figure 3-10
Current of Test and Control Insulators at High Humidity

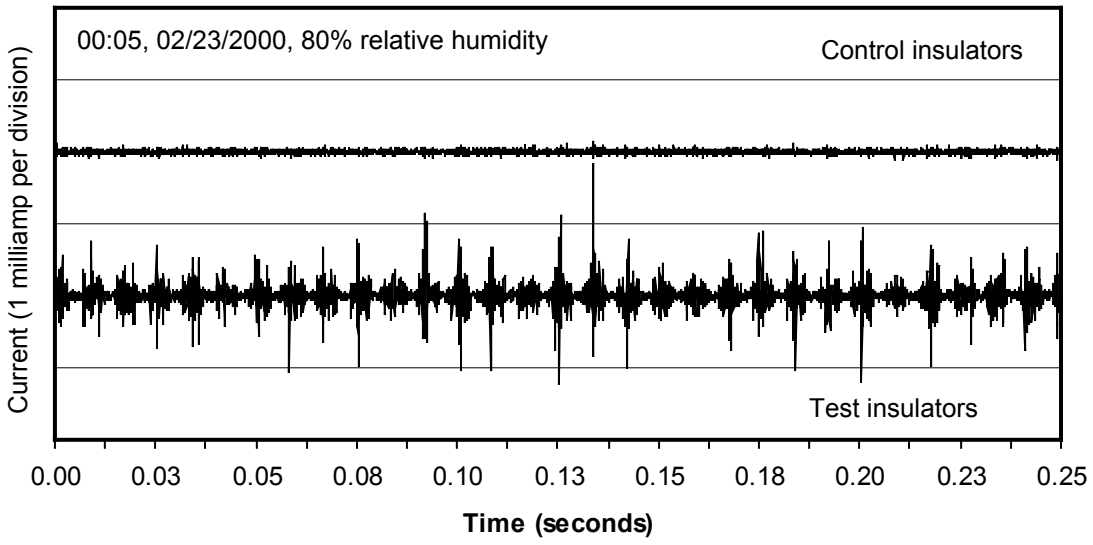


Figure 3-11
High-frequency Current of Test and Control Insulators at High Humidity

Conclusions

The experimental portion of this project was very valuable in several ways:

- It demonstrated that incipient faults produce measurable changes in electrical parameters.
- It confirmed the presence of arcing during incipient faults.
- It demonstrated the heavy influence of moisture on contamination-related incipient faults.
- It demonstrated that the arcing characteristics that incipient faults produce are qualitatively very similar to those of downed-conductor faults.
- It showed that the magnitude of incipient fault currents can be very small, several orders of magnitude smaller than the current from a majority of downed-conductor faults.
- These all point to the potential for anticipating future faults by detecting incipient fault characteristics. Therefore, subsequent tasks in the project moved away from the experimental realm and concentrated on long-term field measurements.

4
PRE-PROTOTYPE DATA COLLECTION SYSTEM

System Design Considerations and Criteria

The previously described experimental work provided initial validation of the hypothesis that incipient faults produce measurable electrical activity. Accordingly, Texas A&M University researchers proceeded to a field-data collection phase. To accomplish this, they designed a pre-prototype data collection system that would make long-term measurements on operating distribution feeders.

The design goals and criteria for this pre-prototype data collection system differed significantly from those that a commercial device would have. For the goals of this project, the intent was to minimize design time and cost as much as reasonably possible. Specific design considerations and criteria included the following:

- Each pre-prototype data collection system was to monitor a single feeder.
- The substations in which the systems were to be installed were to be climate-controlled (i.e., air-conditioned).
- The system was to interface with the electric power system via the utility's standard five-amp current transformers (CTs) and 120-volt potential transformers (PTs).
- The system was to monitor passively. In other words, it was to inject no signals on the power system.
- The system was to monitor common weather parameters (i.e., temperature, humidity, and wind) as well as electrical parameters.
- The number of units to be produced was to be small, on the order of five. Optimal designs can reduce per-unit production costs but the added cost of designing and testing for this level of optimization outweighs the potential benefit when producing a small number of units. Therefore, the total time and cost of design and production were more important than per-unit production considerations.
- The systems were to operate in unmanned substations for relatively long periods of time, on the order of one to two years. Therefore, their hardware and software should be robust enough to operate with little human intervention. Researchers designed for a reasonably high level of robustness without incurring the significant incremental cost of "perfect" robustness.
- The systems were to provide the user with the ability to manage all information that they collected remotely (i.e., from Texas A&M headquarters) via modem.
- The systems were to provide the user with the ability to change all settings remotely.

- The intent was to focus singularly on condition monitoring and fault anticipation, not on optimal hardware or software design. Therefore, designers sought and used off-the-shelf building blocks when practical. For example, they opted for a PC-based platform rather than a fully customized embedded system.
- As additional monitoring functions were implemented, researchers needed to be able to update the pre-prototypes' software every few months. Therefore, the design had to include means for remote software updates, without requiring the host utility to visit the substation or take any other action.

Hardware Design

Researchers designed the pre-prototype data collection system in accordance with the previously outlined design considerations and criteria. The main building blocks of the system included the following:

- Personal computer (PC) – The heart of the hardware system consisted of a 400-Megahertz Pentium II desktop Host PC running Microsoft's Windows 95 operating system. Texas A&M purchased this as an off-the-shelf commercial-grade unit. The Host PC provided two RS232 serial ports, one for connection to a weather logger and the other for connection to a modem.
- Weather logger – Researchers purchased an off-the-shelf weather monitoring and logging system. It consisted of sensors mounted on a weather head and a desktop interface box that provided a local display of all monitored parameters and that served as the interface between the weather head and the PC. The system also provided the various cables that were needed in order to connect the weather head sensors to the interface box and to connect the interface box to one of the Host PC's RS232 serial ports.
- Modem – Researchers selected an off-the-shelf external modem to provide remote communications for the purposes of data retrieval, configuration changes, program code updates, etc. The modem connected to one of the Host PC's RS232 serial ports.
- Analog signal-conditioning (ASC) module – Researchers designed and built a custom analog signal-conditioning module that provided the interface between the power system and the data acquisition boards in the Host PC. This ASC module accepted the power system's current and voltage signals as inputs. It provided for four current inputs from the power system's five-amp current transformer secondary terminals and for three voltage inputs from the power system's 120-volt potential transformer secondary terminals. The next section provides details about this module.
- Data Acquisition (DAQ) boards – Researchers purchased off-the-shelf data acquisition boards from National Instruments and installed them in the Host PC. These boards connected to the ASC module via custom cables. The purpose of the DAQ boards was to convert the analog current and voltage signals, as prepared by the ASC module, into digital format for processing by the Host PC's software.

Figure 4-1 illustrates the basic interconnection of these various building blocks.

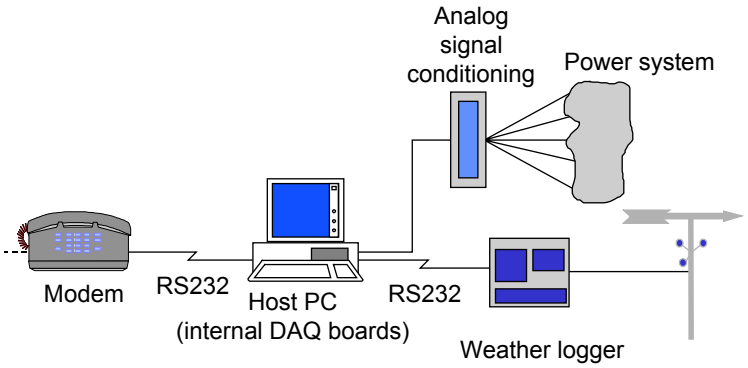


Figure 4-1
Block Diagram of Pre-prototype Data Collection System

Analog Signal Conditioning (ASC) Module

Because of the specialized requirements for the ASC module, it was not possible to purchase such a module off the shelf. However, Texas A&M researchers maintained the philosophy of designing only to the level necessary. Therefore, they purchased individual filter and sensor sub-modules that they then interconnected in order to achieve the necessary conditioning.

The ASC module was key to the success of the project as a whole. Therefore, the design team selected only high-quality components from manufacturers known to be leaders in their fields. For example, they chose current transducers from Pearson Electronics, Inc. Although the cost of these components was significantly higher than that of similar components from other manufacturers, Texas A&M's considerable past experience with Pearson transducers provided a high level of confidence in their fidelity and quality. This approach allowed the researchers to focus more narrowly on the real topic of the project instead of worrying about component quality. In other words, the design team knowingly over-specified critical components in the ASC module so that by spending an extra few hundred dollars, they could maintain their focus on the true topic of the research.

The researchers designed the ASC module so that it would interface with readily available passive substation current and voltage inputs, without requiring specialized sensors. For its current inputs, the module accepted four standard five-amp current transformer (CT) secondary inputs, one for each phase current and one for a neutral or ground return current. For its voltage inputs, it accepted three standard 120-volt potential transformer (PT) secondary inputs.

The ASC module's processing of each voltage signal was relatively straightforward. First, it scaled the 120-volt input signal down to a range acceptable to the analog-to-digital conversion hardware of the data acquisition (DAQ) boards in the Host PC. Then, it passed this scaled signal through an anti-alias (i.e., low-pass) filter, before making it available for connection to the DAQ boards via custom cable.

The ASC module's processing of each current signal was considerably more complex. Three general categories of current-based parameters were of interest: the aggregate waveform, the

band of frequencies containing the low-order harmonics and noise frequencies, and the high-frequency components. The terms "low-order" and "high-frequency" obviously are relative terms. In the context of this project, researchers considered low-order harmonics to be those in the range of several hundred Hertz and high-frequency components to be those in the range of several thousand Hertz.

The ASC module passed each input current signal through its own internal Pearson current transducer, which converted the signal into a proportional voltage waveform that had the proper range for conversion by the DAQ boards. After passing through the current transducer, the ASC module processed the resulting waveform so as to provide four distinct signals to the DAQ boards. Two of the signals represented the aggregate current waveform. The difference between these two involved their relative scales and ranges. One signal's range was approximately 80 amperes while the range of the other was approximately seven amperes. The first allowed the measurement of the full range of expected currents, but with limited resolution. The second allowed higher resolution as long as the signal remained within a normal operating range, but it saturated the DAQ's range for larger currents. The third signal for each current represented the low-order harmonic and non-harmonic frequencies. To obtain this signal, the ASC module passed the signal from the current transducer through a notch filter to remove the fundamental-frequency component and then amplified the remaining signal. The effect of this was that by removing the dominant fundamental-frequency signal, the ASC module could provide greater resolution of the remaining frequencies. The fourth and final signal from each current represented the high-frequency current components. To obtain this signal, the ASC module passed the output of the notch filter through a high-pass filter and then amplified the remaining signal significantly. The result was that this signal provided even greater resolution of those frequency components that were above both the fundamental frequency and the low-order harmonics.

Figure 4-2 illustrates a simplified block diagram of one of the ASC module's voltage channels and one of its current channels.

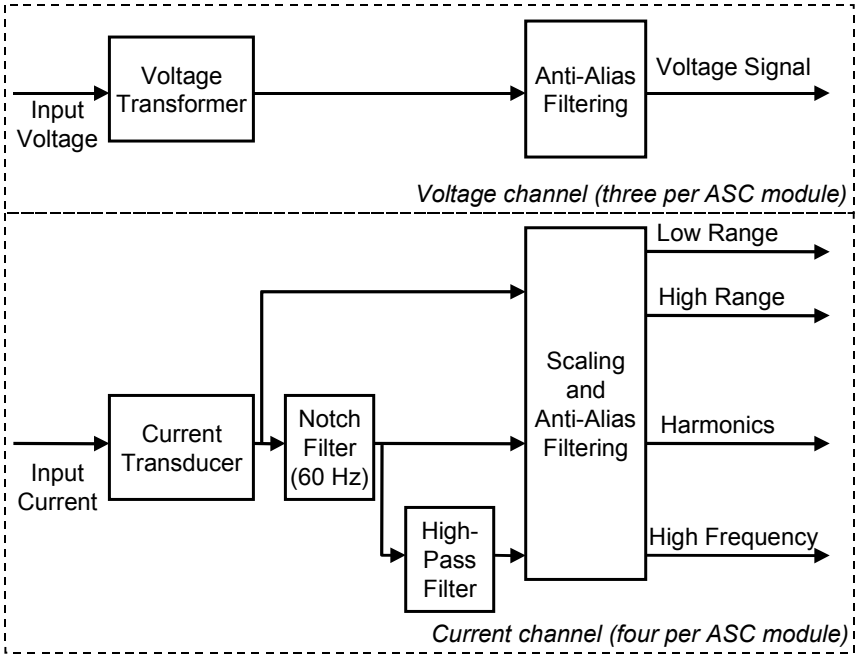


Figure 4-2
Simplified Block Diagram of Analog Signal Conditioning (ASC) Module

Software Design

Because of the atypical functions of the pre-prototype data collection system, there obviously were no prepackaged off-the-shelf solutions for its software. The research team therefore designed and implemented custom system software modules, using version 6.0 of Microsoft's Visual C++ programming language. Their goal was to implement the software in such a way that it was reliable enough to meet the criterion of operating in unattended substations for months at a time, with little or no human intervention. Beyond that, their goal was to implement code that would monitor the power system, collect data, communicate with Texas A&M University headquarters via modem, and perform various housekeeping functions necessary to maintain the system remotely. The goal was not to produce optimal software programming as this would have been beyond the scope and needs of the project.

Programmers configured the Host PC's operating system to start the monitoring program automatically when the PC booted. The program's software consisted of several key modules. The following subsections discuss each of these modules.

Electrical Data Acquisition Module

The electrical data acquisition software module is responsible for configuring, starting, and stopping the DAQ cards and for moving data from the DAQ cards to the Host PC's main memory. Configuration functions include setting the number of channels to sample, the order in

which to sample them, the gain with which to pre-amplify each channel's incoming signal, and the rate at which to sample each channel.

This module also is responsible for determining when the DAQ cards need to be reconfigured and/or restarted. For example, if the user changes a system configuration parameter, the electrical data acquisition software module stops the DAQ cards, sends the new configuration information to them, and then restarts them. Also, if the module determines that the DAQ cards are not responding, it attempts to stop and restart them and, if this fails, it signals the main program that it needs to reboot the Host PC.

Weather Data Acquisition Module

The weather data acquisition software module is responsible for retrieving weather-related information from the weather logger hardware. The desktop monitor that is part of the off-the-shelf weather logger hardware retrieves readings from the sensors that are located on an external weather head. The desktop monitor obtains temperature, relative humidity, and wind readings from the sensors several times per minute. The weather data acquisition software module communicates with the weather logger's desktop monitor via standard RS232 serial communications using a protocol defined by the weather logger's manufacturer.

Electrical Parameter Calculation Module

The electrical parameter calculation software module receives data from the electrical data acquisition software module once per second. It calculates a large number of parameters from these data, as follows:

- For each current, it calculates all harmonic and non-harmonic components below the sixteenth harmonic. It performs this spectral calculation once for each two-cycle interval. For each of the four current inputs, this results in a total of 32 components at frequency intervals of 30 Hertz.
- It calculates the RMS value of each current and voltage input. For each of these seven inputs, it calculates one RMS value for each two-cycle interval.
- For each two-cycle interval, it calculates the real, reactive, and apparent power for each phase, using that phase's current and voltage inputs.
- It calculates the energy of each of the four high-frequency current channels.

Statistical Processing Module

The statistical processing software module receives the calculated values from the electrical parameter calculation software module. It calculates statistics for each parameter (e.g., harmonics, RMS values, power, etc.) over a configurable interval, typically fifteen minutes. At the end of each interval, it is responsible for storing these statistics for each monitored parameter in a long-term database. This results in a database that contains four values per parameter per interval: minimum, maximum, average and standard deviation.

This module also calculates these statistics for the monitored weather parameters at the same configurable interval (e.g., fifteen minutes).

Triggered Data Collection Module

The triggered data collection software module monitors the output of the electrical parameter calculation software module. For each parameter, the module maintains a running average. The module uses this average to establish two adaptive trigger thresholds for each parameter, one a configurable percentage above the average and the other a configurable percentage below it.

Each measurement interval (i.e., every two cycles), the module compares each parameter to the corresponding adaptive trigger thresholds. If the present reading violates either threshold, the module sets a capture-initiation flag in software. In addition, if the present value of the monitored parameter goes above or below configurable absolute thresholds, it sets the capture-initiation flag. The module then performs the same comparisons for all other parameters.

After comparing all parameters to their respective thresholds for the present measurement interval, the module checks the state of the capture-initiation flag. If it is set, the module initiates a high-speed data capture and then clears the flag. This initiation process consists of opening a disk file on the Host PC and writing information to a predefined area at the beginning of the file. This information consists of the location (i.e., utility and substation), the time and date, the values of the configurable settings at the time of the capture, etc. While a high-speed data capture is in process, the module streams all "raw" data from the electrical data acquisition module (i.e., all data from the DAQ boards) into a disk file.

During subsequent measurement intervals, if any parameter continues to violate any trigger threshold, the module continues to set the capture-initiation flag. The effect of this is that it extends the duration of data captured to file. The module ends the data capture only when no parameter violates any configurable threshold for a period of time, typically four seconds. As a result, a single threshold violation results in a high-speed data capture that lasts for a total of five seconds, one second in which there are threshold violations followed by four seconds in which there are no such violations.

Event Logging Module

The event logging software module is responsible for creating a permanent record of all anomalies and other events of interest. Its purpose is multifold. First, by logging software anomalies, it helps the software's programmers to find and fix problems in subsequent versions of the software itself. Second, it logs certain problems with the hardware, such as instances of the electrical data acquisition software module having to restart the DAQ cards when they fail to respond properly. Third, it creates a log of events such as the program being started and stopped or a configurable setting being changed.

Remote Communication Module

The remote communication software module is key to a project in which the system's operating location is unattended. The remote communication software module allows researchers to accomplish almost all functions remotely that they could accomplish if physically sitting in front of the Host PC itself. Several of these functions are key.

Modify configurable settings

The software contains numerous configurable settings. It contains configurable settings about the monitored circuit, such as CT and PT ratios. It also contains settings related to data captures, such as the thresholds at which the triggered data collection module is to initiate data captures. The remote communication software module allows the user to modify all of the configurable settings remotely.

Manage Files

The triggered data collection software module creates a unique file each time it initiates a high-speed data capture. The remote communication software module allows researchers to list these files and selectively retrieve them from the Host PC to a PC at Texas A&M's headquarters. More generically, the module allows researchers to browse the contents of any folder (i.e., directory) on the Host PC's hard disk and retrieve any file from it. The module also enables researchers to transfer files to the Host PC's hard disk from a remote location, which is necessary to accomplish program updates. Finally, the module allows researchers to delete files selectively in order to prevent the Host PC's hard disk from becoming too full.

Retrieve Statistical Data

The statistical processing software module stores the various statistics for each monitored parameter in a database. The remote communication software module allows researchers to select and retrieve particular parameters for particular periods of time.

Restart Program or Host PC

In order to perform program updates and for other miscellaneous reasons, it is sometimes necessary to restart the pre-prototype's software. It also is sometimes necessary to reboot the Host PC's operating system. The remote communication software module provides researchers with the ability to command the system to take either of these actions.

Housekeeping Module

The system's software consists of a number of other minor modules with a variety of functions. For example, a watchdog function is responsible for periodically making sure that all of the other modules continue to function and for restarting the program or rebooting the Host PC's operating

Data Collection Philosophy

When utilities apply data recorders, their goal generally is to capture specific events of interest, such as overcurrent faults. They configure these data recording devices such that they will record events that meet known, well-defined conditions. For example, to record overcurrent faults, one would set the recording device to initiate a capture if the measured current exceeded a set number of amperes. Similarly, to record voltage dips, one would set the recording device to initiate a capture if the measured voltage fell below a predetermined level.

Setting the criteria under which the recording device initiates captures involves tradeoffs. A utility with a large number of feeders and recorders must balance the desire to record all events of interest with the reality that overly sensitive triggers will result in an overabundance of data. Human analysis of such an overwhelming amount of data is prohibitively expensive, especially if overly sensitive capture criteria cause the recording devices to capture many "non events." Therefore, utilities often select relatively high thresholds for triggering data captures in order to ensure that they record only those events that have a significant present impact on the system's operation, even if this means that they miss more subtle events.

By contrast, the desire in this project was to capture all events that might indicate future problems. Obviously, at the beginning of the project, researchers could not specify precisely what criteria would constitute such events. Therefore, their philosophy was to capture all events that showed any "unusual" behavior and analyze the captured data later to determine the cause. This necessarily meant that a large number of the captured events would be "non events" and that the process of analyzing the large quantity of such events would be manpower-intensive. However, with a relatively small number of monitored feeders, they determined this to be an acceptable approach.

The researchers anticipated that many of the events of interest would be quite subtle, often much smaller in absolute terms than many normal system events. For example, an incipient fault in its early stages might produce only a few amperes (or even less) of primary current flow, much less than many loads. The researchers' thesis was that there would be measurable, recognizable characteristics that would enable discrimination between incipient fault current and normal load current, but these characteristics were unknown at the beginning of the project. Their philosophy therefore was to use the overabundance of data captures to learn to trigger captures more intelligently in the future.

5
CASE STUDIES

After designing, constructing, and testing pre-prototype data collection systems as described in Chapter 4, Texas A&M University used these systems to monitor four distribution feeders, one pre-prototype data collection system per feeder. One feeder was at a local substation that Texas A&M uses for various ongoing experiments. This location provided researchers an ideal location at which to perform initial validation of the system's robustness, its ability to communicate reliably via modem, etc. It was readily accessible and close enough to Texas A&M headquarters to facilitate on-site visits when needed while validating the initial software, before installing systems at more remote utility substations. Later, each time researchers implemented a change to the system's software, they validated its reliability at this local substation for several weeks before installing it at the other locations.

The other three feeders were at substations of EPRI members. The specific utility companies, substations and feeders were as follows:

- TXU Electric, Northeast Tyler Substation, Feeder 1605
- Rochester Gas and Electric, Station 69, Feeder 5160
- Alabama Power Company, part of Southern Company, Midfield Distribution Substation, Breaker 3, Feeder 08276

The participating utilities selected these feeders based upon several criteria, including the following:

- History of incipient-type failures (e.g., tree contact, insulator failures, etc.)
- Availability of telephone line of suitable quality for high-speed modem access
- Environmental conditioning suitable for pre-prototype system operation

The remainder of this chapter presents a series of case studies of events that the pre-prototypes recorded at these four locations, but it does not identify the particular location of any specific event. Each case study will illustrate and discuss measured waveforms. It also will discuss the underlying power system phenomena that caused the incipient waveforms for cases in which that information is known.

Lightning Arrestor Failure

Case Summary

A lightning arrestor failed catastrophically on one of the feeders that a pre-prototype data collection system was monitoring. The failure eventually caused an overcurrent fault that resulted in a trip and reclose of the substation breaker. Weather conditions at the time of the failure and fault were generally clear and sunny. Sprinkles of rain were reported in the area on the day of the failure but it is not known whether any were present at the actual location or time of the fault. It is unfortunate that the lightning arrestor's type and vintage are unknown but the utility's records did not contain this information and the fault completely destroyed the arrestor, making post-fault analysis impossible.

The pre-prototype data collection system first saw early indications of the incipient failure three days prior to the actual fault. The system triggered and recorded waveforms over a period of approximately one-and-one-half hours but then detected no additional anomalies and therefore recorded no additional waveforms for nearly three days. On the third day following, the system began to detect anomalies and record waveforms almost continuously. After approximately ten minutes, it recorded the overcurrent fault and breaker trip that the arrestor's final failure caused.

The following subsections provide a timeline of the events that the pre-prototype system recorded. They also provide an overview of the analysis of these recordings. The analysis reveals that the recorded waveforms contained distinct, recognizable arcing characteristics.

Recorded Data

Day 1: September 13, 2000

Figure 5-1 shows the current and voltage waveforms that a pre-prototype data collection system measured on September 13, 2000. There is no apparent cause for concern. The only obvious thing of note from these waveforms is that the current seems to have a high level of harmonic distortion. One notes the general symmetry about zero, i.e.,

$$f(t + T/2) = -f(t),$$

where T is the period of the fundamental frequency. Mathematical analysis shows that a signal that strictly obeys the previous equation contains only odd harmonics of the fundamental frequency. While the current waveform in Figure 5-1 does not strictly obey the equation, it is very close, which indicates that most of the harmonic distortion is at the odd harmonic frequencies.

The level of distortion appears significant, but in reality this amount of harmonic distortion is quite common in the currents on distribution feeders. Therefore, while interesting, the distortion itself is no apparent cause for concern.

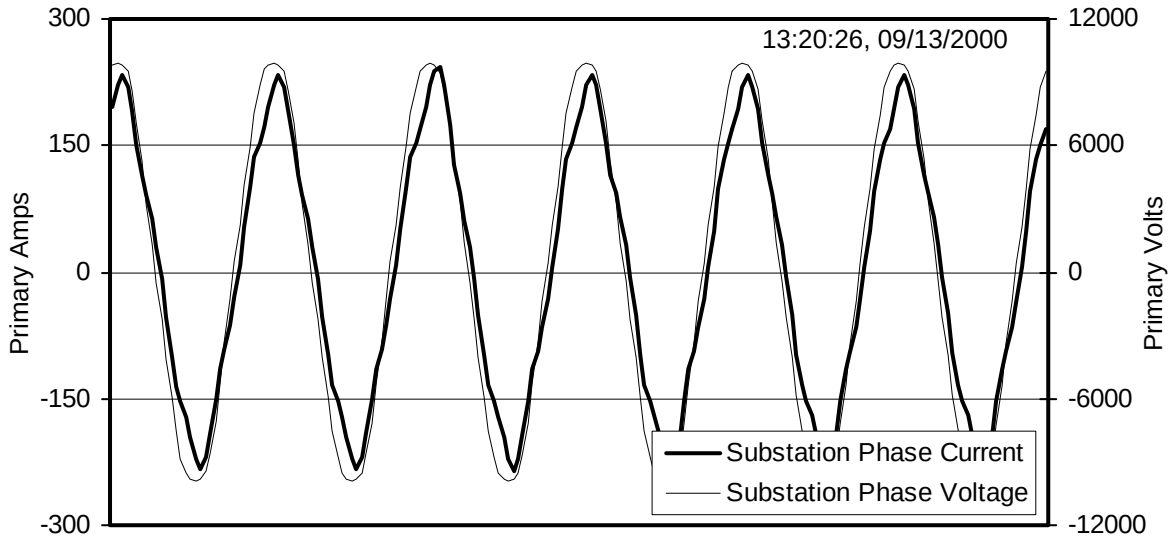


Figure 5-1
Substation Currents and Voltages Three Days before Arrestor Failure

Texas A&M University researchers have developed an algorithm for dynamically estimating steady-state load current waveforms. During analyses such as this present one, they use this algorithm to estimate the steady-state signal and then mathematically remove it from the measured signal. The result is a waveform that estimates cycle-to-cycle variations from steady state. They have found this to be a useful tool for analyzing the type of relatively small incipient changes that often are masked by dominant load currents. In many of the figures that follow, some of the signals are labeled as "substation" and others as "incipient." In this context, "substation" refers to signals that the pre-prototype directly measured from the substation CTs (or PTs in the case of voltages) and "incipient" refers to signals that have been processed to remove steady-state components.

Figure 5-2 shows the current of Figure 5-1 after the previously described algorithm has been applied to remove the steady-state load current. The resulting incipient current waveform makes dynamic cycle-to-cycle variations obvious. Specifically, there is a significant sub-cycle current burst of approximately 29 peak amperes. It is noteworthy that of the six cycles shown, there is a burst of current in only one half-cycle. Of further note, although Figure 5-2 does not show it explicitly, this was the only half-cycle of current that showed such a burst during the captured data's entire five-second duration.

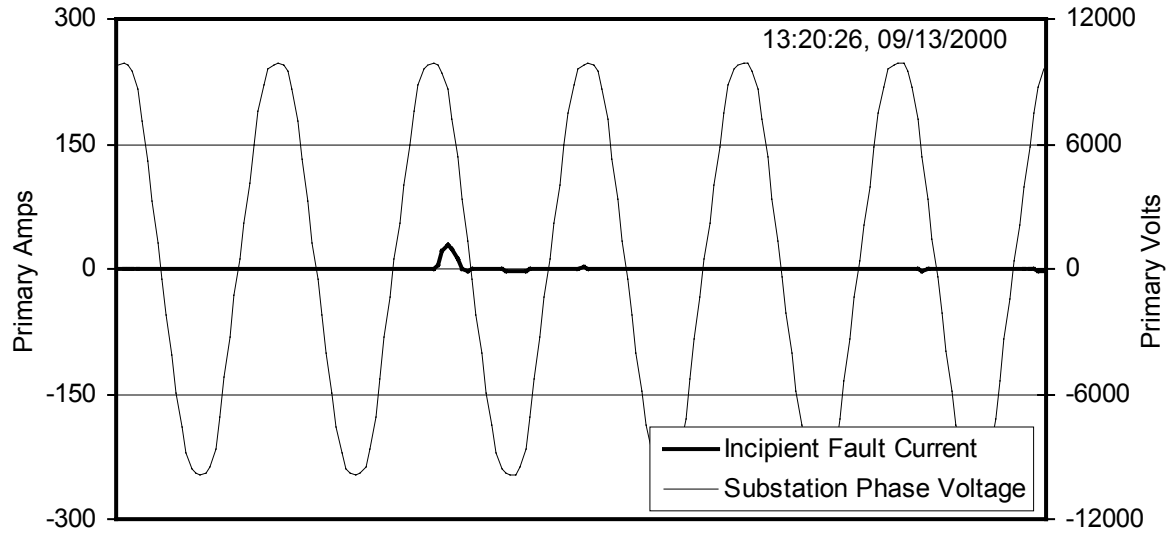


Figure 5-2
Substation Current of Figure 5-1 with Steady-state Components Removed

The burst of current in Figure 5-2 first appeared to be an isolated event. However, approximately 87 minutes later, the pre-prototype data collection system measured another very similar event. Figure 5-3 shows this burst of current. The two measurements are very similar in several ways:

- Each incipient fault current waveform has the same general shape.
- Each burst of incipient fault current has a peak magnitude of approximately 29 amperes.
- Each burst of incipient fault current is approximately one quarter of one cycle in duration.

The pre-prototype measured two other similar bursts of incipient fault current, approximately five and ten minutes after the burst of Figure 5-3. In each case, the burst of incipient current was very similar to the two already shown, each having the same general shape and duration. In addition, each had an incipient fault current peak of approximately 27 amperes, only slightly lower than the 29-ampere peaks of the first two measurements.

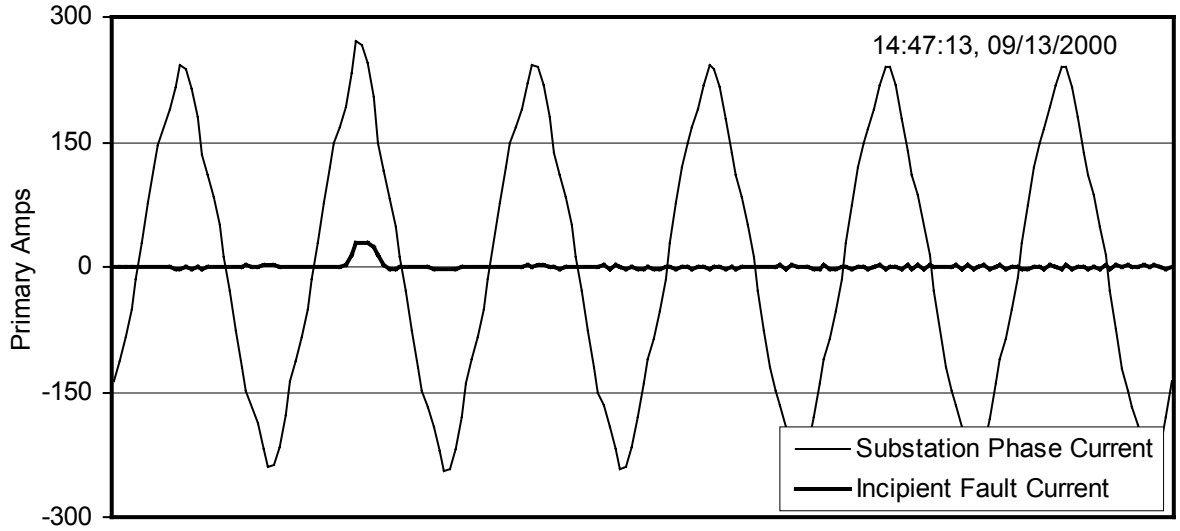


Figure 5-3
Substation Current 87 Minutes after That Shown in Figure 5-2

Day 3: September 16, 2000

After measuring these four events, the pre-prototype recorded no further events of this type until nearly three days later, at which point it again began to register bursts of incipient fault current. In comparison to the behavior on the first day, the bursts that occurred on this third day occurred much more frequently. Figure 5-4 shows the first event that the pre-prototype measured following the three-day hiatus. The general magnitude and shape of the waveform are very similar to the earlier measurements. The most obvious difference is that this measurement consists of three distinct incipient fault current bursts over a period of one-and-one-half cycles.

Figure 5-5 shows the incipient high-frequency current signal that the pre-prototype system recorded at the same time it recorded Figure 5-4, with the phase voltage shown as a reference.

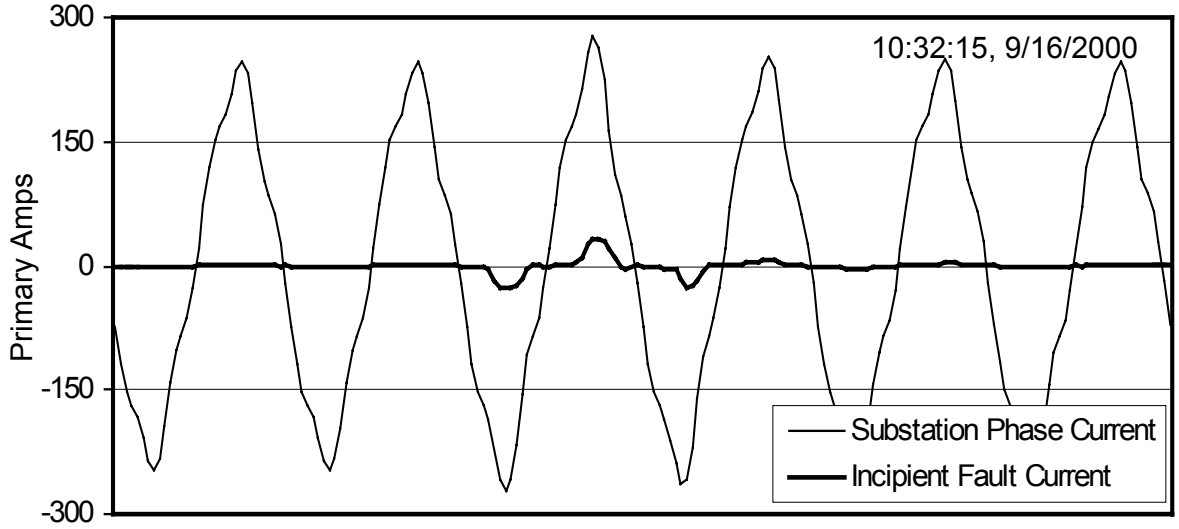


Figure 5-4
Substation Current Three Days after That Shown in Figure 5-3

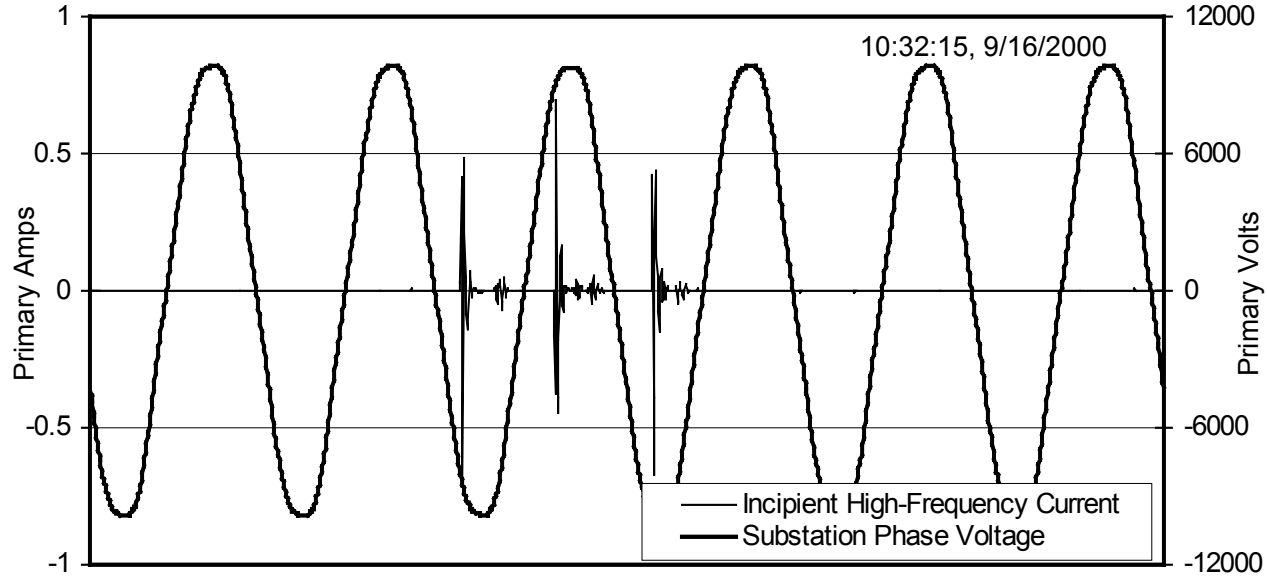


Figure 5-5
Substation High-frequency Current Corresponding to Figure 5-4

On the first day the pre-prototype detected these events, there were only four isolated bursts. Starting with the burst shown in Figure 5-4, the number and frequency of such bursts increased dramatically. Because of this, it becomes impractical to illustrate each waveform separately. Instead, the following sequence of figures presents calculated RMS values, both of the overall current signal and of the high-frequency current signal.

Figure 5-6 illustrates the calculated RMS values for the substation and incipient current waveforms shown in Figure 5-4. The brief RMS current increase at approximately 0.4 seconds

corresponds to the three half-cycles of incipient current illustrated in the waveform figure. Similarly, Figure 5-7 illustrates the calculated RMS values corresponding to the substation and incipient high-frequency currents of Figure 5-5. Figure 5-8 and Figure 5-9 show similarly processed RMS data for a one-minute period that began two minutes before the arrestor failed.

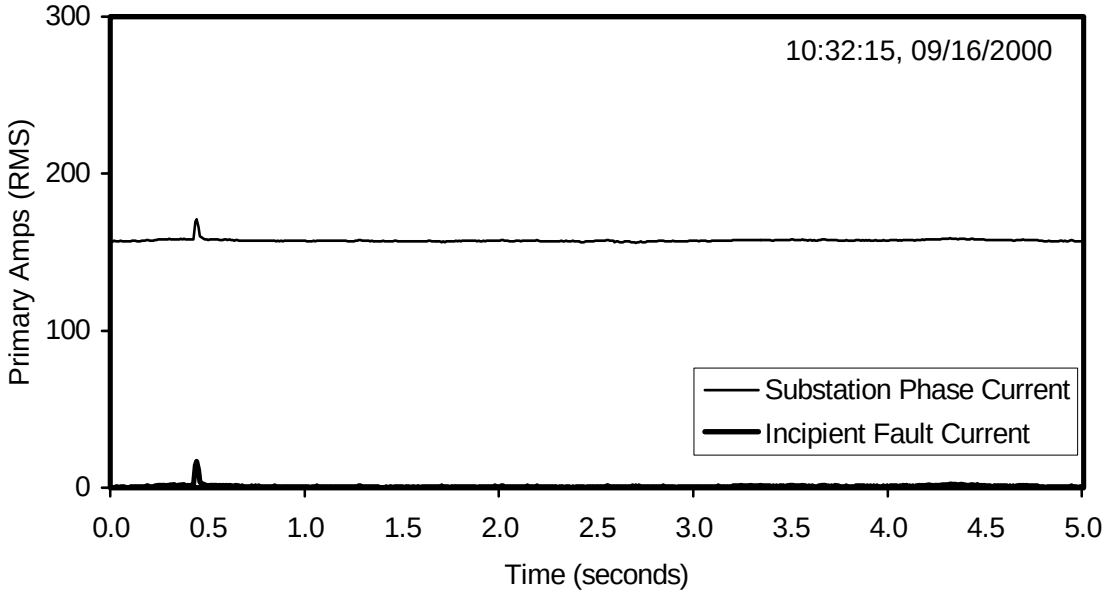


Figure 5-6
RMS Currents Corresponding to Figure 5-4

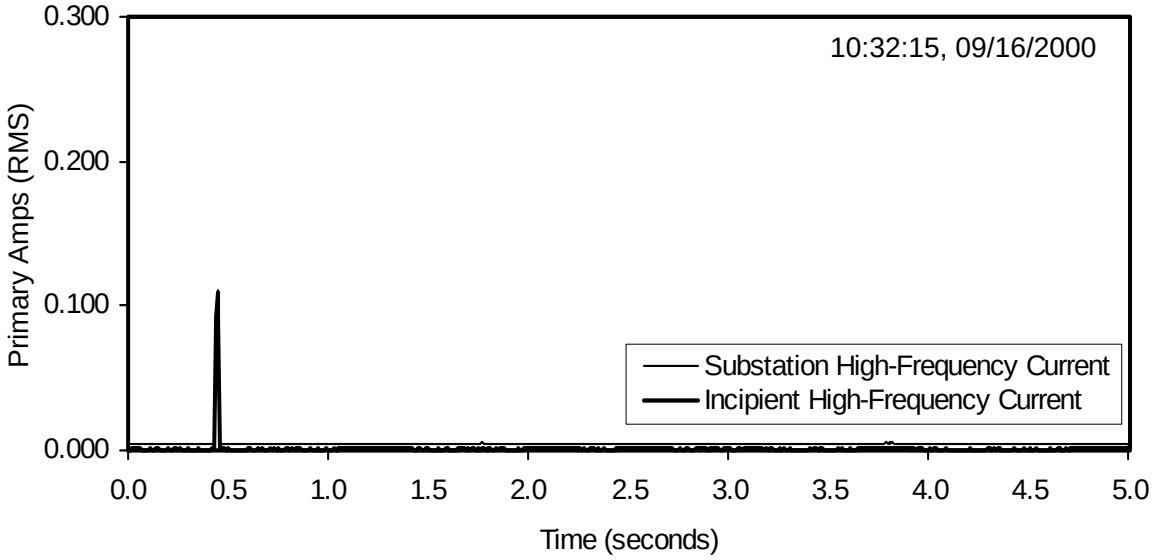


Figure 5-7
RMS High-frequency Currents Corresponding to Figure 5-5

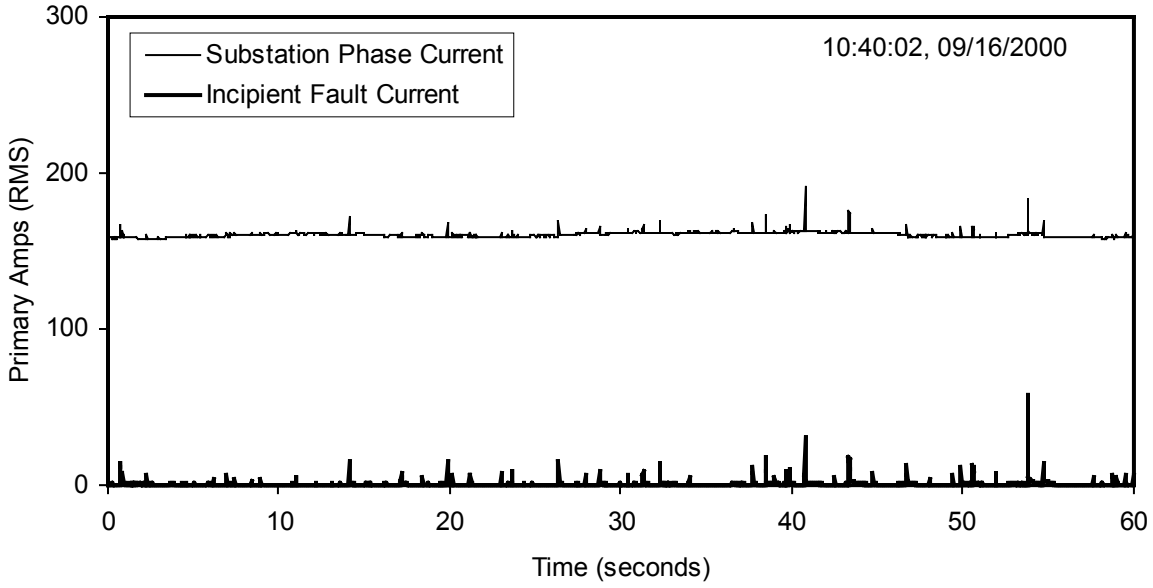


Figure 5-8
RMS Current Two Minutes before Catastrophic Failure

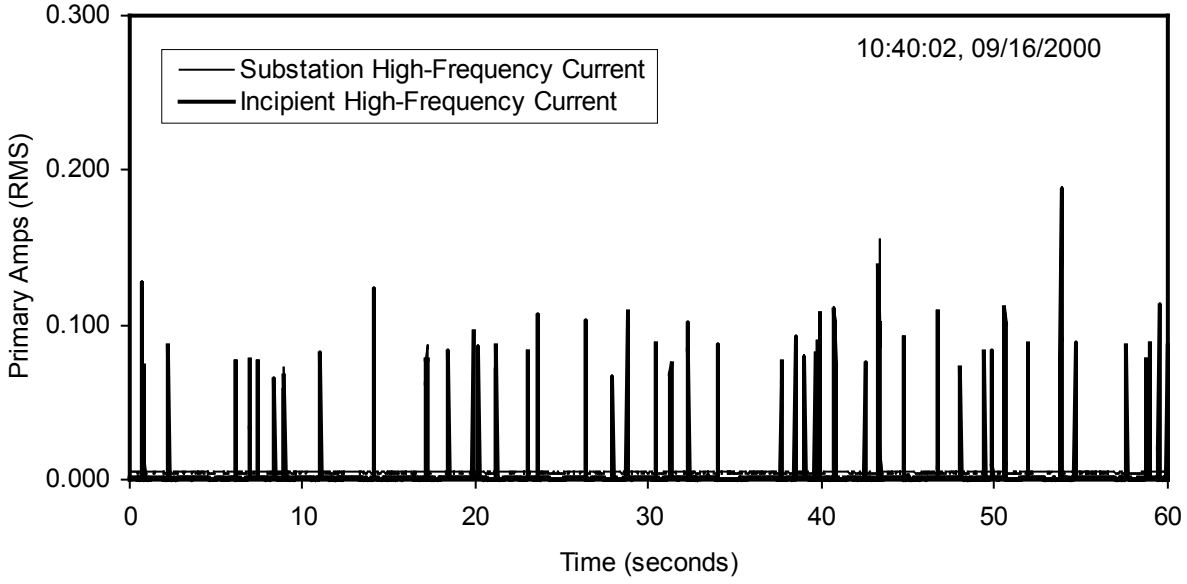


Figure 5-9
RMS High-frequency Current Two Minutes before Catastrophic Failure

After approximately ten minutes of this near-continuous behavior, the lightning arrestor failed completely. This resulted in an overcurrent fault that tripped the substation breaker. Figure 5-10 shows the measured substation phase currents for the phase on which the failed lightning arrestor was installed and for one of the adjacent phases. The lightning-arrestor phase registered a line-to-ground overcurrent fault for approximately nineteen cycles, during which time the

magnitude varied somewhat but generally stayed between 3400 and 3625 primary RMS amperes. Then, the fault evolved into a phase-to-phase-to-ground fault, presumably because of flying debris from the failed arrestor. During this period of the fault, the RMS phase current was approximately 3800 amperes on the lightning-arrestor phase and approximately 4100 amperes on the adjacent phase. This phase-to-phase-to-ground portion of the fault lasted for approximately five cycles before the substation breaker tripped. Figure 5-11 shows that the breaker stayed open for just over five seconds and then reclosed, restoring service.

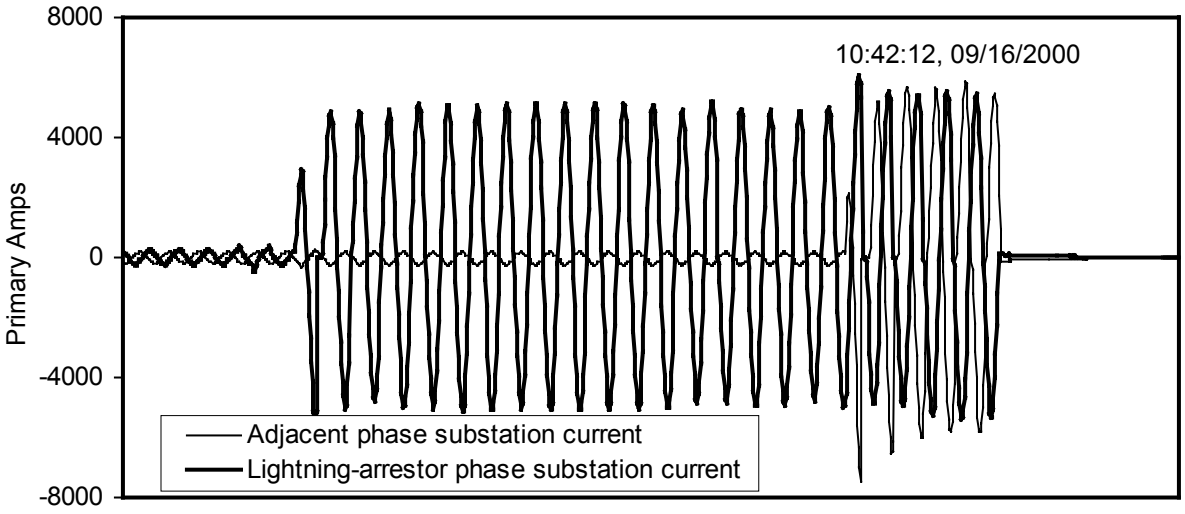


Figure 5-10
Substation Current Waveforms during Lightning Arrestor Failure

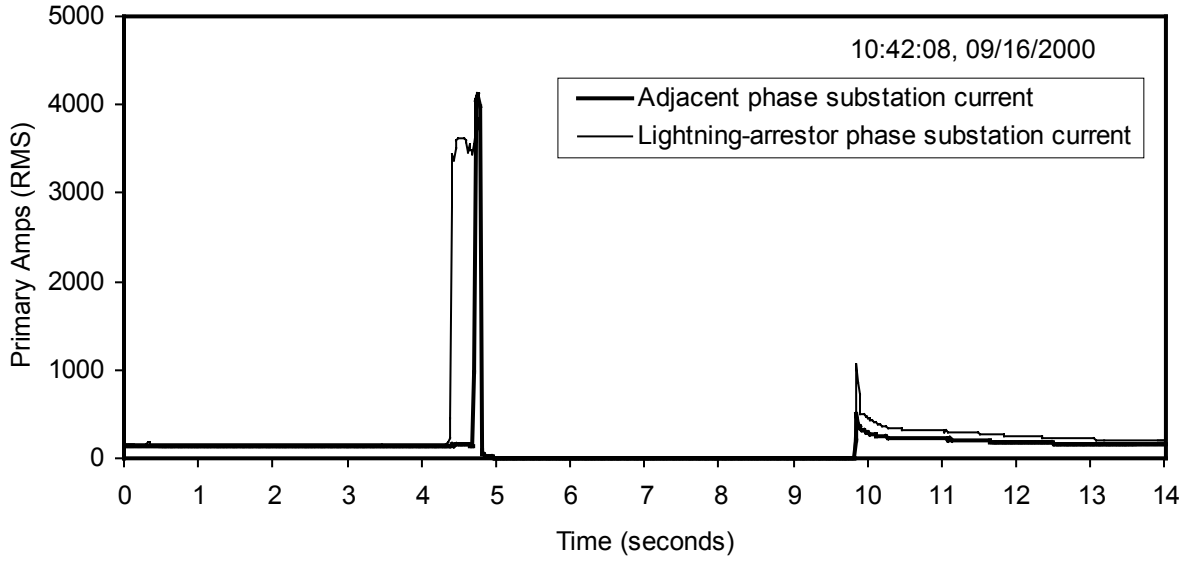


Figure 5-11
RMS Substation Currents during Lightning Arrestor Failure

Analysis of Recorded Data

An earlier chapter discussed the process and characteristics of arc initiation and extinction (see section entitled "Discussion of Arc Characteristics" in Chapter 3). The incipient fault current waveforms that the pre-prototype data collection system recorded in the days leading up to the lightning arrestor failure exhibited these classical arc characteristics.

Figure 5-2 is a good illustration of the gross characteristics of arc establishment and extinction. The burst of incipient arc current initiates when the system voltage is rising toward its peak. Then, the arc burst extinguishes itself shortly before the voltage returns to zero.

Similarly, Figure 5-5 agrees with the predicted high-frequency current pattern that occurs during arcing. In each half-cycle in which there is an arc burst, there are two distinct bursts of incipient high-frequency current. First, there is a relatively large burst of incipient high-frequency current coincident with the initiation of the incipient arc current. Then, toward the end of each such half cycle, there is a second, smaller burst of high-frequency current coincident with arc extinction. Between the two bursts, the level of high-frequency activity is larger than before the arc begins, but significantly smaller than during the distinct initiation and extinction bursts.

It should be noted that it was dramatic increases in this high-frequency component that triggered the preceding data captures (Figure 5-1 through Figure 5-9). For instance, the burst of current shown in Figure 5-1 caused the calculated RMS of the high-frequency current to increase from an ambient level of approximately four milliamps to well over 100 milliamps during the burst.

Case Discussion

This case demonstrated the fundamental premise underlying this project. Specifically, it demonstrated the presence of measurable changes in electrical signals well in advance of catastrophic failure. By anticipating such a failure, utilities could schedule a preemptive replacement of the arrestor. This would have several benefits:

- Preventing customer interruptions and outages
- Preventing stress to other system equipment (e.g., transformers, breakers, etc.)
- Allowing repairs to be done during regular working hours, using on-duty crews. In this particular case, the arrestor's failure occurred on a Saturday. This required the utility to incur the extra expense of calling in a crew. It would be equally likely for such a failure and outage to happen during nighttime hours, similarly necessitating the call-in of a crew.

Although not surprising, it is unfortunate that more information is not available about the particular arrestor. It would be beneficial to know the age of the arrestor and, perhaps more importantly, its operating principle (e.g., gap-type arrestor, metal-oxide varistor, etc.). Knowing the type could prove quite useful when comparing to arrestor failures that may be recorded in the future, particularly if different parameters change or if the parameters behave differently.

To date, because of the small number of pre-prototype data collection systems (i.e., four) and the relatively short period of time (i.e., less than two years) that they have been monitoring operating feeders, this is the only example of lightning arrestor failure in the collected library of events. Research personnel hope to gather additional examples of this type of failure during the anticipated next phase of the project. Because the number of monitored feeders is anticipated to increase very significantly, they believe it statistically likely that this will happen.

Parametric Change after Tree Trimming (Feeder 1)

Case Summary

Two of the utilities that provided installation sites for pre-prototype data collection systems have significant problems with trees contacting overhead lines. Accordingly, one of these utilities selected a feeder that was scheduled to have its trees trimmed several months after the pre-prototype's scheduled installation date, as part of the utility's normal scheduled trimming program. The utility did not notify the trimming crew that this feeder was part of a monitoring project because they did not want the trimming crew to treat it differently than they would treat any other feeder.

The pre-prototype data collection system on this feeder was able to collect data for approximately three months before the crew trimmed the area that the feeder serves. At the time of the writing of this report, the system had been monitoring the feeder for approximately one year after the trimming occurred.

The pre-prototype data collection system registered a significant, precipitous change in one of the monitored parameters, coincident with the time the tree-trimming crews were working in the area containing the monitored feeder. This parametric change persisted in the months following tree trimming.

Recorded Data

A previous chapter outlined the method with which the pre-prototype data collection system calculates and stores statistical data about the behavior of various electrical parameters. The interval over which the system calculates and stores these statistics in a database is configurable, but research personnel generally configure this for fifteen-minute intervals.

One such parameter is the RMS value of the high-frequency component (i.e., the cumulative band of frequencies in the range of several thousand Hertz) of the substation current. Among other things, the pre-prototype's database stores the average of this RMS high-frequency current every fifteen minutes. The following series of three figures illustrates this average high-frequency value over the period of one year, each figure showing a four-month period. The data come from the time-driven statistical database, not from triggered high-speed data captures.

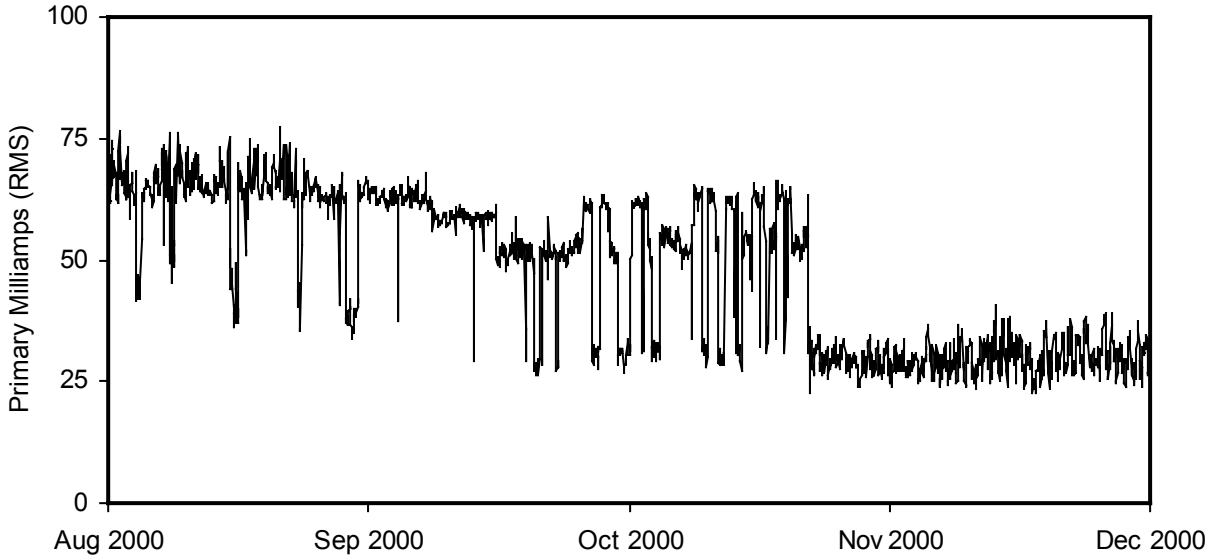


Figure 5-12
High-frequency Substation Current, August - November 2000

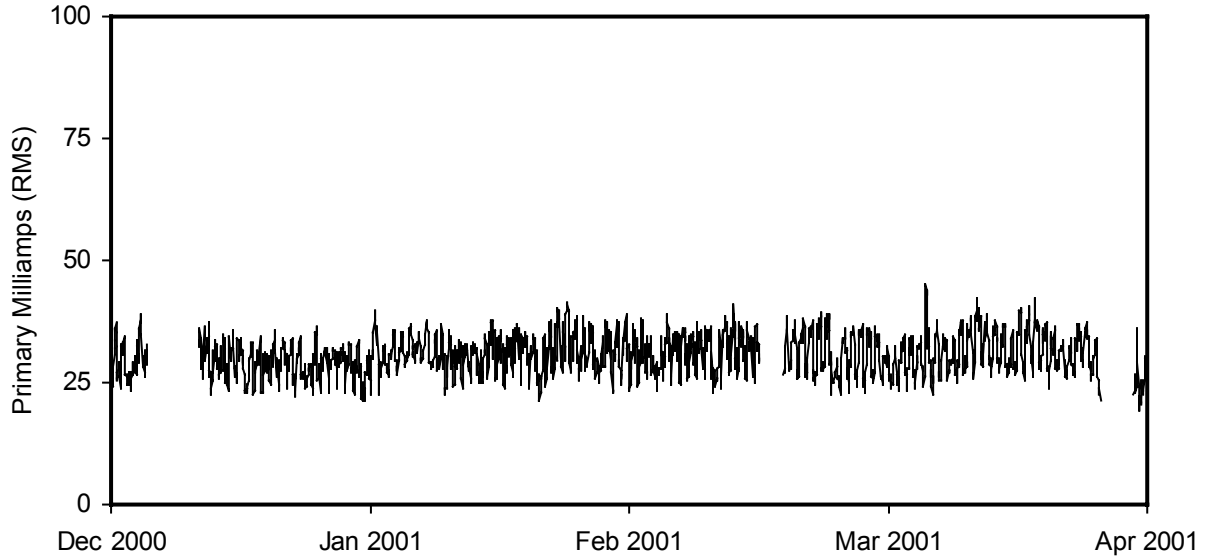


Figure 5-13
High-frequency Substation Current, December 2000 - March 2001

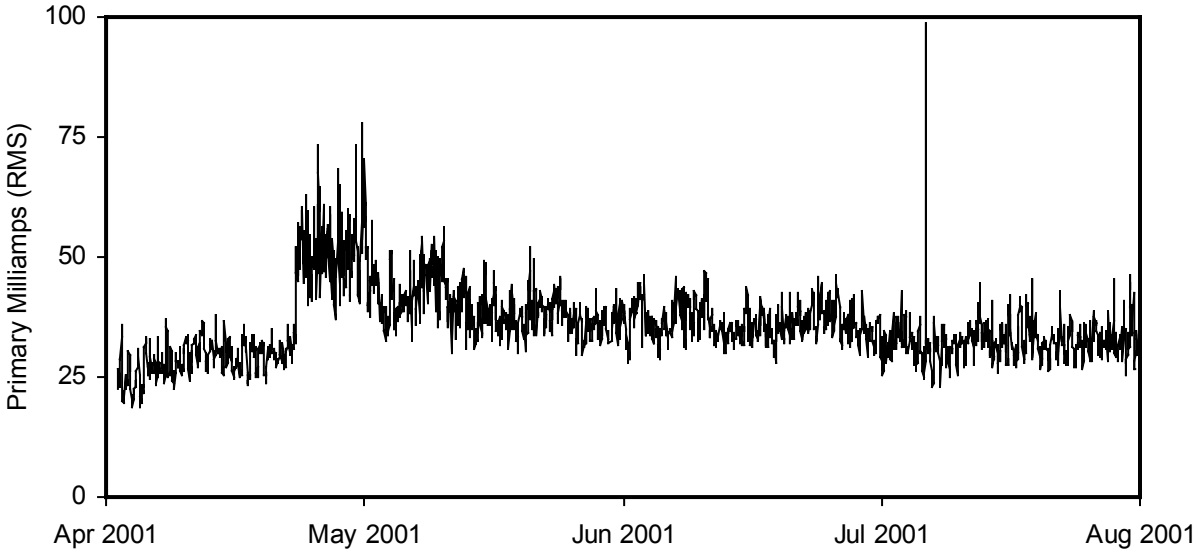


Figure 5-14
High-frequency Substation Current, April - July 2001

Analysis of Recorded Data

The host utility conducted regularly scheduled tree trimming of the feeders in the area during October 2000. Figure 5-12 shows the first four complete months of data that the pre-prototype data collection system recorded, including the time of the trim.

Figure 5-12 makes obvious the change in high-frequency current that occurred coincident with the tree trimming. Not only is there an obvious change in the average, but the variability in the average changes as well. Prior to the trim, the high-frequency average had numerous precipitous step changes between levels of about 65 milliamps and 30 milliamps. After the trim, the average was about 30 milliamps and did not exhibit the precipitous changes.

Figure 5-13 shows the next four-month period, December 2000 through March 2001. In this figure, there are three gaps in the data, each lasting several days. These gaps indicate time periods during which the pre-prototype data collection system was out of service or disconnected from the power system, so that no data were available. The main observation from this figure is that, during this period of time, the high-frequency current continues to behave just as it did immediately after the tree-trimming activity.

Figure 5-14 illustrates the average high-frequency current during the third and final four-month period, which begins approximately five-and-one-half months after the utility trimmed the trees. At least two interesting points can be made about this figure. First, the high-frequency activity is elevated noticeably for about the last one-third of April 2001. Second, during the last three months in the figure (May - July 2001), the high-frequency current is somewhat higher than it was between November 2000 and early April 2001. However, it still is considerably lower than it was before the tree trimming occurred and the precipitous step changes have not returned.

Case Discussion

The change in level of high-frequency current, coincident with the known time at which the utility performed tree trimming on the feeder's right-of-way, was very dramatic. The host utility confirmed that tree trimming began during the same week in which the measured parametric change occurred. It is prudent to note that this singular case does not prove a definitive causal relationship between the trimming activity and the measured change, but the relationship certainly seems probable. Fortunately, another pre-prototype data collection system measured two instances of similar changes in the same parameter and each instance was coincident with tree trimming as well. The case study presented next will provide further information on that case.

Further discussion of the high-frequency current's behavior is in order. It is noteworthy that after the high-frequency current drops (see Figure 5-12) it stays at the new lower level for at least the next ten months. This tends to indicate causality. The one exception appears approximately six months after the initial drop, in April 2001 (see Figure 5-14). During this time period, the high-frequency current parameter increases significantly and then tapers off over a period of a few weeks. The cause of this increase is unknown but one explanation seems likely. The month of April is during the spring of the year and vegetation generally grows most vigorously during this part of the year. This may cause new growth to make significant contact with overhead primary conductors. Because the utility had trimmed these trees relatively recently, however, it is likely that the new growth that contacts the line would consist of small ends of branches, which would burn clear relatively quickly after making contact with the primary. By contrast, when the trees near a feeder have not been trimmed recently, many of the branches that contact the conductor will be larger and thus more difficult to burn free. This explanation is speculative, but the fact that the high-frequency current increases for a few weeks and then decreases fits the pattern of vigorous tree growth during the first few weeks of spring followed by less vigorous growth during the following summer months.

The pre-trim parametric behavior of Figure 5-12 is interesting as well. In the two-and-one-half months preceding the trim, there are many obvious step changes, both in the positive direction and in the negative direction. Texas A&M researchers have no firm explanation for this, but a reasonable explanation might be that non-electrical forces result in periodic changes in the amount of contact between tree limbs and overhead conductors. For example, a change in wind direction might cause offending limbs to move enough to cause temporary contact or, alternatively, to interrupt contact temporarily.

If one makes the reasonable assumption of causality between the tree-trimming activity and the precipitous drop in high-frequency current, this case study presents a very significant and exciting finding. Tree trimming is a very costly part of preventive maintenance, but it is necessary in order to prevent service problems such as voltage dips, momentary interruptions and sustained outages. A utility normally must trim trees on rights-of-way on a predetermined schedule that is conservative enough to maintain an acceptable level of service even on the worst-performing feeders. A tool that would allow the utility to target tree trimming to those feeders on which significant contact actually is occurring has the potential to save vast amounts of maintenance money while at the same time minimizing tree-related feeder disturbances. This

case study suggests that anticipating tree-related faults and thereby targeting available maintenance resources may be possible.

This case study shows a definite parametric change that occurs when a utility performs routine feeder-wide tree trimming. Not enough time has elapsed since the trimming occurred to assess how the affected parameter behaves as trees grow back over time. Researchers hopes to gain this type of information during the anticipated next phase of the project.

Parametric Change after Tree Trimming (Feeder 2)

Case Summary

The previous case study demonstrated the measurable parametric change that occurred coincident with routine tree trimming on one of the feeders that a pre-prototype data collection system was monitoring. This present case provides evidence of similar parametric changes that occurred under similar conditions on another such feeder.

In the previous case, the utility selected the particular feeder for pre-prototype installation based upon its existing plans to trim the trees on the feeder's right-of-way a few months after that pre-prototype's installation. By contrast, in the present case, the utility did not plan to trim trees on the monitored feeder but emergency conditions required it to do so in order to restore service to the feeder. Then, several months later the utility performed additional tree trimming on the feeder's right-of-way.

The feeder that provides the basis for this present case study is located in an area in which tree contact causes a significant number of interruptions and outages. This area experienced a severe winter storm in December 2000. The storm caused widespread outages from a variety of causes, including numerous tree limbs breaking or sagging into overhead primary conductors. Before the utility could restore service to its customers, it had to perform emergency tree trimming on a wide area including this feeder.

The high-frequency current parameter that the pre-prototype data collection system monitors showed a significant decrease when the utility restored service to this feeder after trimming trees. Months later, the utility performed additional trimming and the high-frequency current parameter again showed a precipitous drop, this one even more dramatic than the first.

The following series of figures illustrates this parameter's behavior for a sixteen-month period. The figures provide before-and-after data surrounding both of the trimming events.

Recorded Data

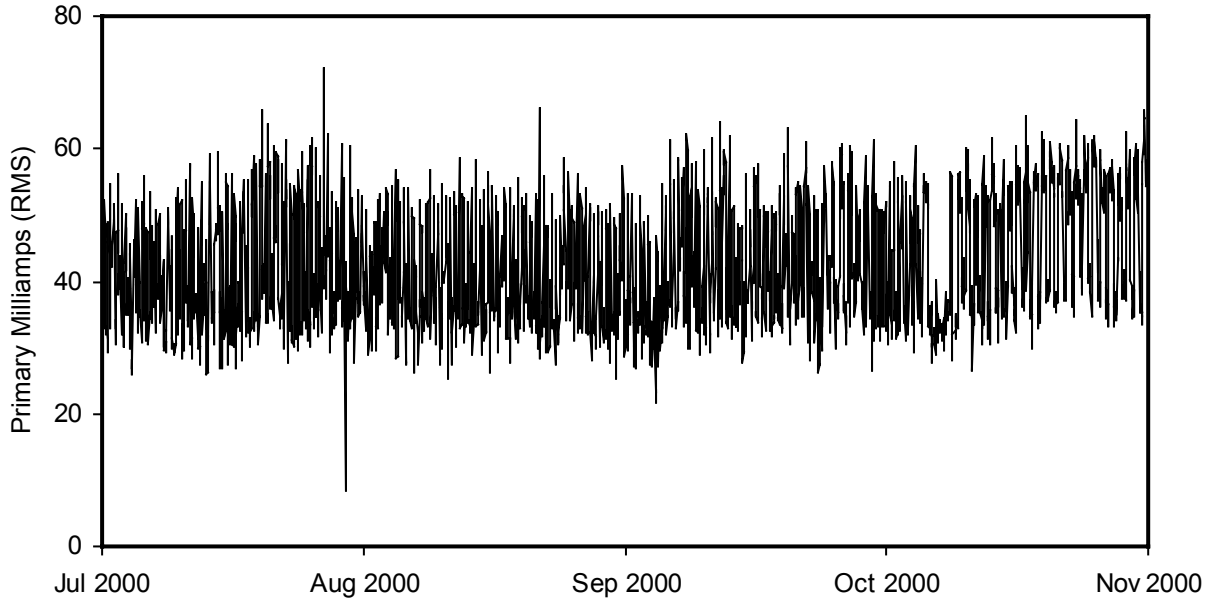


Figure 5-15
High-frequency Substation Current, July - October 2000

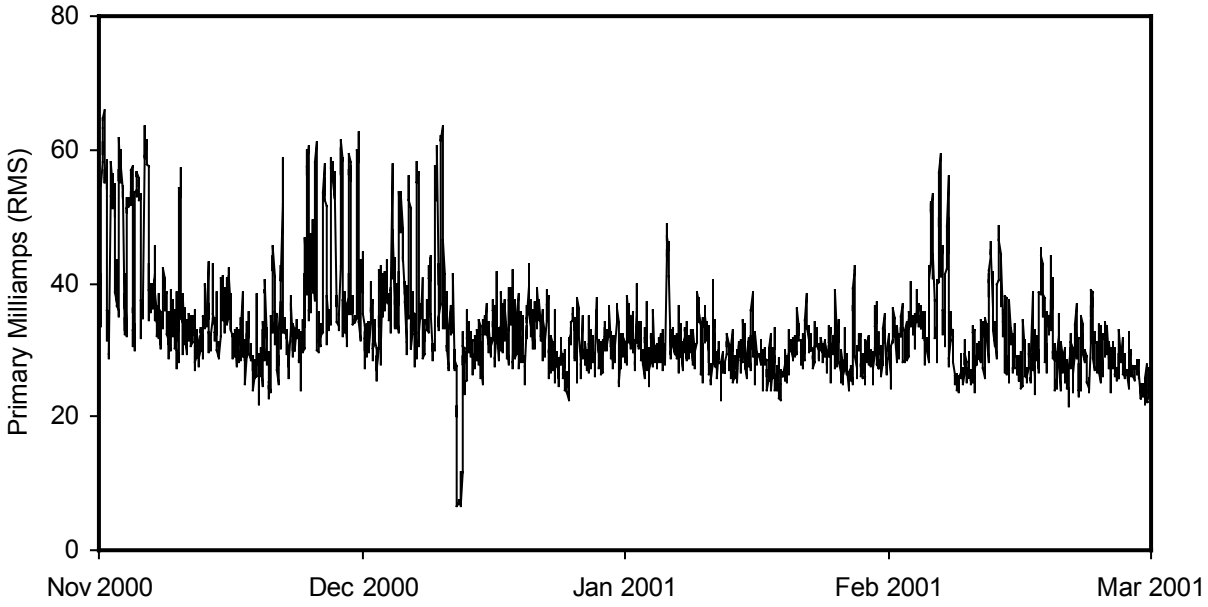


Figure 5-16
High-frequency Substation Current, November 2000 - February 2001

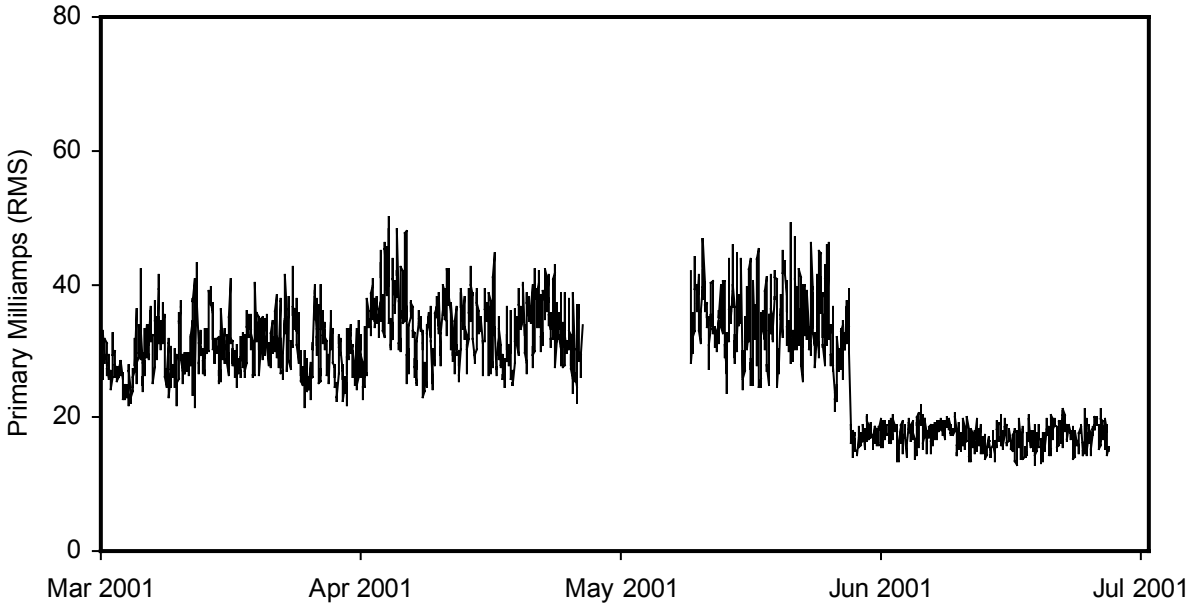


Figure 5-17
High-frequency Substation Current, March - June 2001

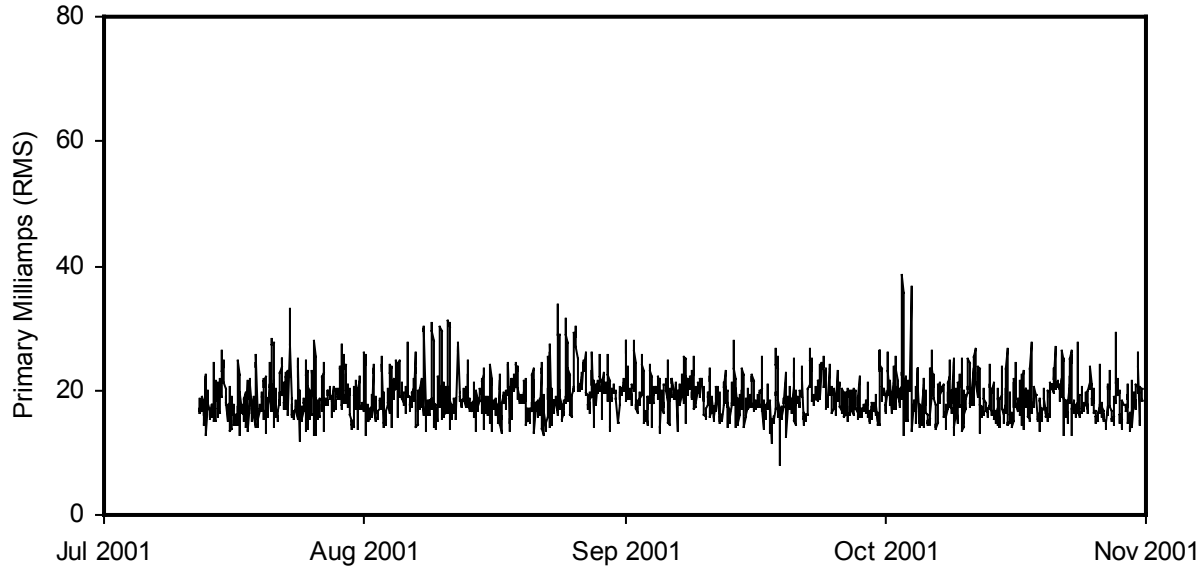


Figure 5-18
High-frequency Substation Current, July - October 2001

Analysis of Recorded Data and Utility Actions

In December 2000, a massive ice storm occurred in the area served by the feeder that this pre-prototype data collection system monitors. This forced widespread outages that took the utility days to restore. The outage on this particular feeder lasted for approximately fifteen hours on December 13, 2000. During this period of time, crews performed a substantial amount of emergency tree trimming in and around the area that the feeder serves in order to clear limbs and trees that the ice had caused to fall or sag into the overhead primary.

Figure 5-15 illustrates the high-frequency current level that the pre-prototype measured on this circuit for a four-month period before the ice storm occurred. The figure shows that the high-frequency current generally varied from about 25 to 60 primary milliamps and that the level varied from the lower end of this range to the upper end of this range frequently on a day-to-day basis.

Figure 5-16 illustrates the next four-month period, including the time period surrounding the ice storm. The first one-and-one-half months of this figure show behavior similar to that seen during the previous four-month period. Then, on December 13, 2000, there is a sudden, sustained drop in the high-frequency parameter. After this date, the daily range narrows generally to 25 to 40 primary milliamps. This new behavior holds fairly consistently for approximately two months. Then, in early to mid February 2001, there is a period of several days during which the parameter's level and variability increase.

Figure 5-17 shows the third four-month period. The blank periods in the figure indicate times that the pre-prototype data collection system was out of service, the first from April 27 to May 10 and the second from June 29 to July 12. For approximately the first three months of this figure, the level and variability of the high-frequency current parameter behave generally as they did after the December 2000 ice storm. However, there does appear to be a gradual increase in both the level and the variability.

The later portion of Figure 5-17 is quite dramatic. The level and variability of the high-frequency current parameter drop precipitously on May 28, 2001. Further, this change is sustained through the remaining four to five weeks of Figure 5-17.

The research team noted the precipitous change and requested that the host utility provide information about any maintenance that they had performed on this feeder during the corresponding time period. The utility responded that they had indeed performed tree trimming during that period of time.

Figure 5-18 shows the fourth and final four-month period, ending with the time of the writing of this report. The level and variability of the high-frequency current parameter are still quite low when compared to their initial levels in Figure 5-15. However, both the level and the variability are beginning to creep back up slightly as time passes.

The geographic area that this feeder serves is marked by very significant exposure to tall, fast-growing trees. The obvious conclusion is that the trees are beginning to grow back, causing proportional increases in the high-frequency current.

Case Discussion

This case provided further confirmation of the speculative conclusions from the previous case study. It is encouraging that, taken together, there now are three instances that illustrate similar parametric changes coincident with feeder tree trimming. No single case, taken by itself, proves causality between the trimming and the parametric change. However, taken together, the likelihood that there is a causal relationship increases dramatically.

As mentioned in the discussion of the previous tree-trimming example, it is hoped that the anticipated future phase of this project will provide information on parametric changes as trees grow back and contact with overhead primary increases. This would be the truly useful result because it would provide the basis for tools to anticipate when tree contact is becoming severe enough to start causing problems, thereby allowing utility companies to schedule tree trimming in a more informed way.

Repetitive Overcurrent Fault (Feeder 1)

Case Summary

On June 12, 2001, a pre-prototype data collection system began to detect relatively frequent overcurrent faults on the feeder that it was monitoring. Over a four-day period, this system recorded five overcurrent faults.

Researchers analyzed the faults and noted that each fault shared certain characteristics. For instance, all faults were single-line-to-ground faults and all occurred on the same phase. In addition, there were other similarities between all five measured faults.

On the fourth day, Texas A&M researchers notified the host utility of the situation and provided all available information. Based upon this information, the utility dispatched a crew to investigate. Within a few hours, the crew was able to find the cause of the problem. They found that a jumper from the overhead primary to the bushing of a service transformer was overlong. They also found several dead birds on the ground near the transformer's pole. They concluded that when a bird landed on the jumper, the bird's weight caused the jumper to move enough to cause contact between the jumper and a ground wire. Utility personnel were able to effect repairs the same day that the research team notified them of the problem. Following that, the pre-prototype measured no additional overcurrent faults that matched the previously noted characteristics.

Recorded Data

The pre-prototype data collection system measured a series of five overcurrent faults relevant to this case. Figure 5-19 illustrates the substation phase current waveform that the pre-prototype measured at the substation during one of these faults. Then, the next series of five figures show the calculated RMS values of the faulted phase current that the system measured at the substation, one figure per instance.

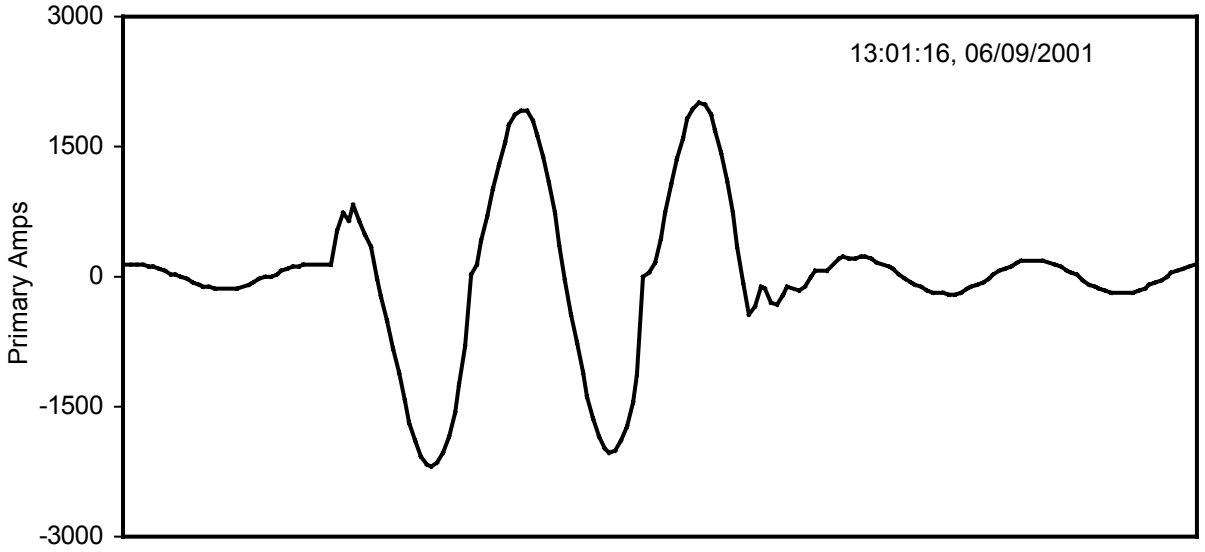


Figure 5-19
Substation Current during One Instance of Repetitive Fault

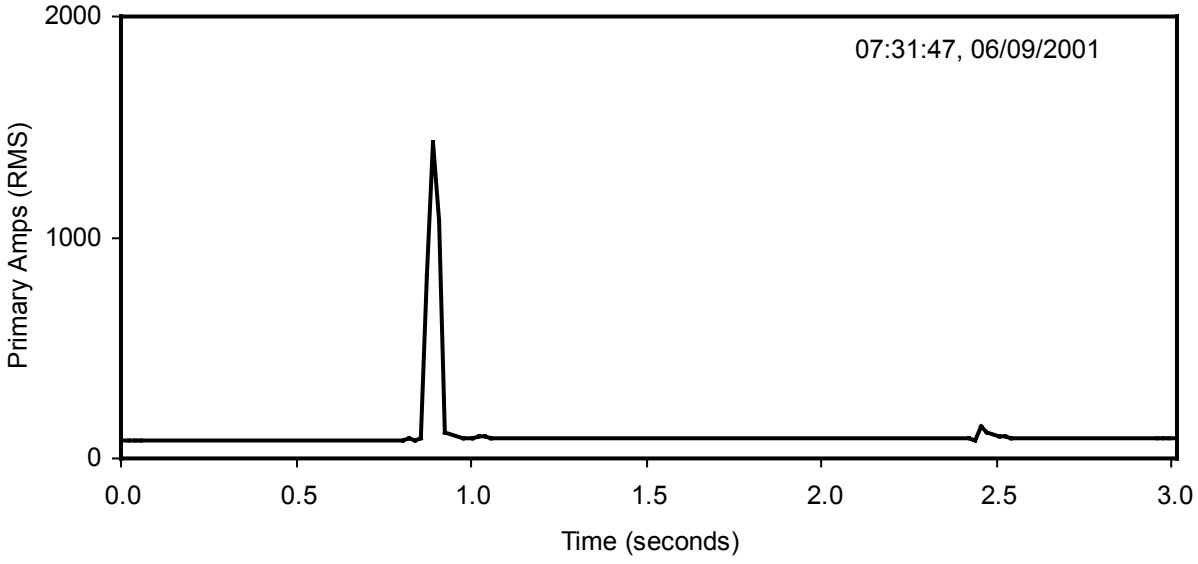


Figure 5-20
RMS Substation Current during First Instance of Repetitive Fault

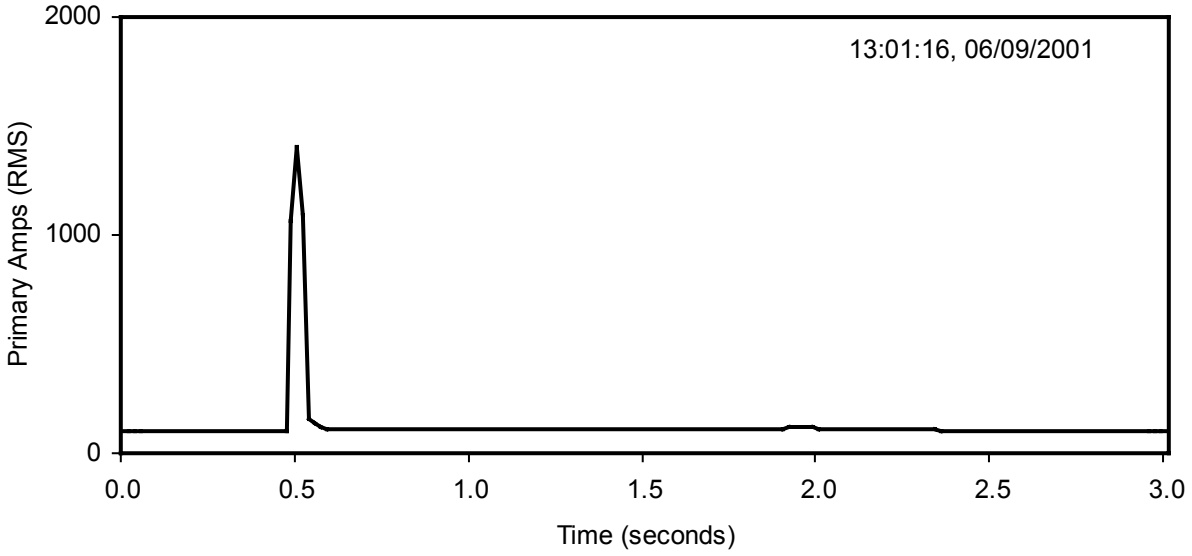


Figure 5-21
RMS Substation Current during Second Instance of Repetitive Fault

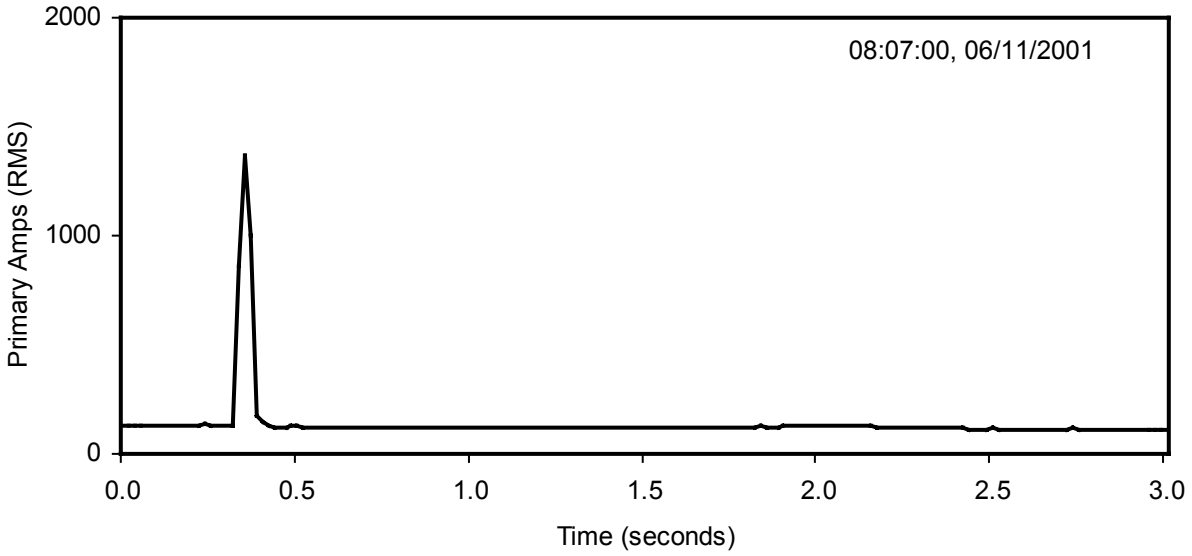


Figure 5-22
RMS Substation Current during Third Instance of Repetitive Fault

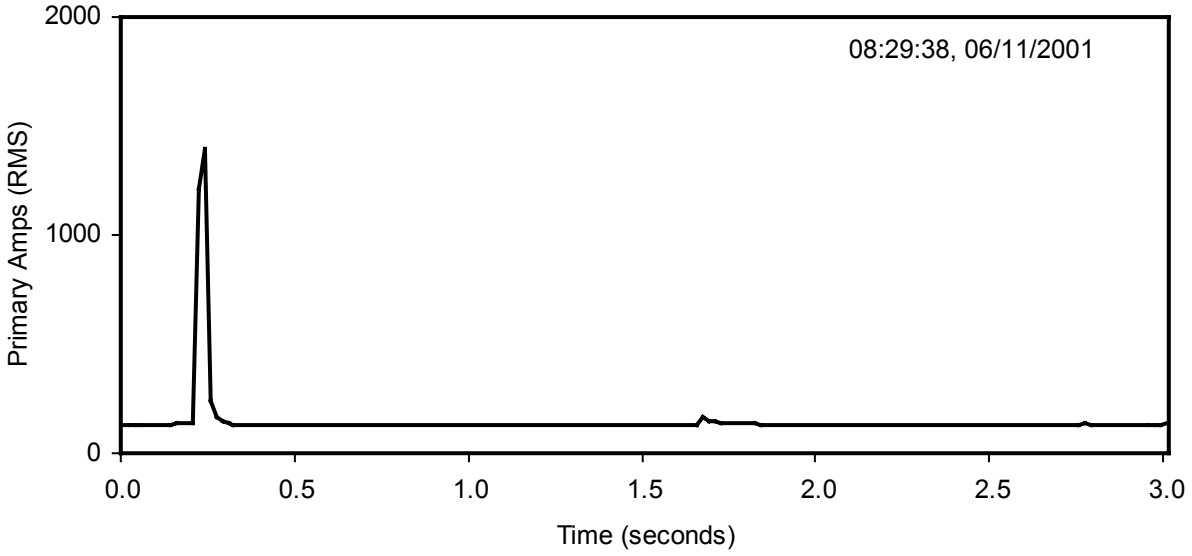


Figure 5-23
RMS Substation Current during Fourth Instance of Repetitive Fault

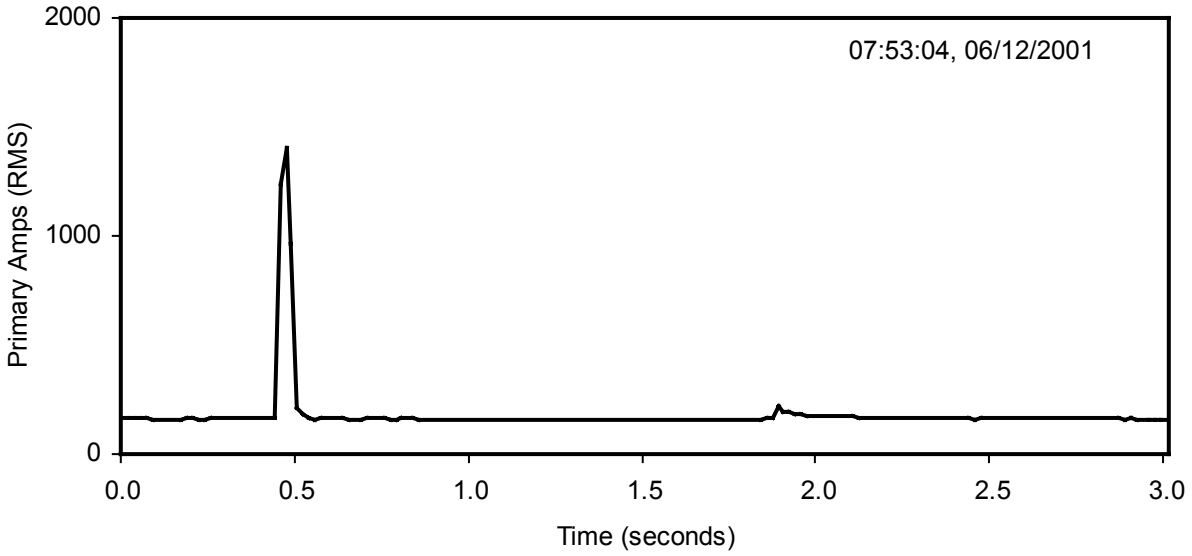


Figure 5-24
RMS Substation Current during Fifth Instance of Repetitive Fault

Analysis of Recorded Data

The previous series of figures reveals that these five overcurrent faults share several common features, including the following:

- In each case, the maximum RMS current at the substation was between 1273 and 1398 primary amperes. In statistical terms, the mean of these values was 1320 amperes and the standard deviation was 57 amperes. Note that researchers used the previously described algorithm for eliminating the steady-state load component from the measured current before calculating these RMS values (see discussion preceding Figure 5-2 for algorithmic details).
- The duration of the overcurrent was between two and two-and-one-quarter cycles in each instance.
- The measured data reveal that a three-phase recloser opened once in each fault instance. This is most obvious in Figure 5-20, which shows a definite reclose transient at the 2.4-second mark. The reclose transient is not as obvious in some of the other figures, but after the research team performed further processing, they were able to discern a definite reclose transient in each case. They observed that the maximum time to reclose was 1.52 seconds and the minimum was 1.39 seconds. Statistically, the mean reclose time was 1.43 seconds, with a standard deviation of 70 milliseconds (approximately four cycles).

Figure 5-19 reveals another characteristic of interest. Namely, there is obvious distortion around the positive-going zero crossing in the fault current. This may be indicative of arcing in the fault path, which would be consistent with a casual contact between a phase conductor and a ground.

Utility Notification and Response

Early on the day that the fifth instance of this fault occurred, the research team notified the host utility of the problem and provided the utility with the information presented in the previous subsection. The utility responded quickly and dispatched a line crew to find and fix the problem.

This particular utility has a practice of visiting each recloser on its system approximately once per month. During these visits, the utility records the value of each recloser's operations counter. Therefore, because they knew that each instance of this fault caused a recloser to operate, the line crew's first action when investigating this problem was to visit each recloser on the monitored feeder and compare the present reading of the operations counter with the most recent routine reading. They found that one recloser had registered a significant number of operations since the last routine reading. The line crew therefore continued its patrol downstream of the recloser. Doing so, the crew soon came upon a pole at the base of which they found several dead birds. They then inspected the hardware at the top of the pole.

Atop this pole was a service transformer that was fed by one phase of the overhead primary. Upon close inspection, the line crew found that the jumper wire that connected the feeder primary conductor to the transformer's bushing was longer than it should have been. They determined that it was long enough to contact the ground wire on the pole. Based upon this observation and upon the presence of the dead birds at the base of the pole, they concluded that the overlong jumper was contacting the ground intermittently whenever birds landed on it.

Upon finding the problem, the line crew effected a simple repair by shortening the jumper wire. The utility then notified Texas A&M researchers of their findings. In turn, the researchers paid

special attention to the pre-prototype data collection system's records for the next several weeks and saw no further instances of this fault.

It is noteworthy that the utility involved in this case was very responsive when presented with the pre-prototype's information. In fact, they initiated the search and were able to find and correct the problem within eight hours of initial notification of its existence. It also is noteworthy that the utility had received no customer complaints during the four-day interval over which the overlong jumper had caused problems.

Case Discussion

This case is different from the previous ones in that it demonstrated the use of real-time monitoring to identify a different category of incipient faults. Specifically, it demonstrated the ability to identify incipient problems that are causing conventional protection to trip and reclose, but that are doing intermittently, thereby allowing the underlying cause to persist and cause problems indefinitely. In each instance, the recloser operated properly to open when a bird caused a jumper to short to ground. By the time the recloser restored service approximately one-and-one-half seconds later, the bird was no longer present and the jumper again was in the clear. The incipient fault then remained dormant until the next unlucky bird happened along.

In this case, relatively few customers actually experienced a momentary outage because the fault occurred near the end of the monitored feeder. However, all customers on the feeder experienced a significant sag in voltage for at least two cycles each time the fault occurred. Furthermore, these sags were at the substation bus, so in reality the sags extended to every customer on each feeder emanating from the bus.

The Information Technology Industry Council (ITIC) publishes voltage-tolerance design curves that represent design criteria for "information-technology equipment." Figure 5-25 shows these curves, which are available on the Internet at *http://www.itic.org/technical/iticurv.pdf*.[5] ITIC recommends that manufacturers design their equipment to "ride through" voltage sags and swells of various magnitudes for at least the durations that these curves specify.

Each instance of the fault in this case lasted between two and two-and-one-quarter cycles, during which time the substation voltage sagged to between 55 and 58 percent of its pre-fault value. According to the ITIC sag tolerance curve, sags of this depth may begin to affect connected equipment when their durations exceed 20 milliseconds (i.e., 1.2 cycles). Therefore, each of the measured instances of this fault violated the ITIC design criterion and had the potential to cause connected equipment to malfunction.

If the research team had not alerted the utility to this problem and provided information from the pre-prototype data collection system, this incipient-fault condition would have remained on the feeder longer and likely would have caused additional sags and interruptions. The utility would not have known of the problem until alerted by some other means, perhaps a customer complaint. However, because all customers on the feeder experienced sags that violated the ITIC sag-tolerance curve, such a call would not necessarily have come from a customer beyond the recloser that operated. In such a case, location of the fault would have been more difficult. For

example, the information from the system provided evidence that a recloser was operating and gave characteristics about its operation (time-current relationship, open interval, etc.). Every such piece of information has the potential to help the utility find the problem and to do so more quickly, which of course equates to happier customers and less cost.

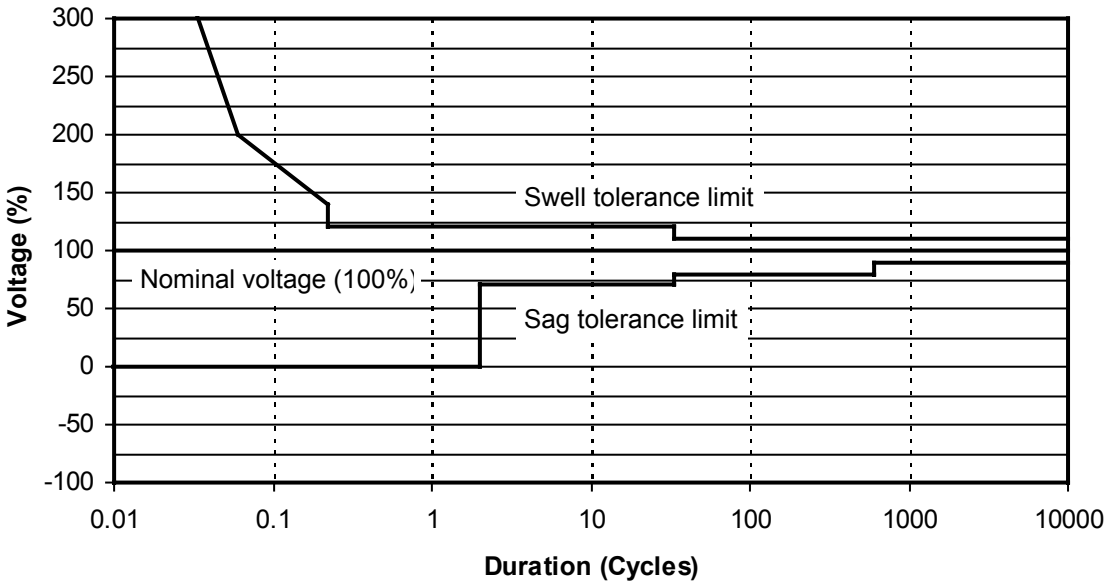


Figure 5-25
ITIC Voltage-tolerance Design Curves

One would like to believe that utility companies currently have means to locate this kind of problem within a few days or, at worst, within a few weeks. However, this is not always the case, as the next case will demonstrate.

Repetitive Overcurrent Fault (Feeder 2)

Case Summary

The preceding case reviewed an intermittent fault that Texas A&M University researchers and the host utility were able to identify, locate, and repair quickly by using data from the pre-prototype data collection system on that feeder. This present case reviews a similar series of events on another monitored feeder.

The feeder in question had a history of a relatively large number of overcurrent faults from the time the pre-prototype data collection system started monitoring it. Starting in August 2000, the frequency of faults became significantly larger. Upon further analysis, researchers determined that a large percentage of these faults shared many common characteristics:

- Each was single-phase and occurred on the same phase.
- Each had a very similar magnitude.
- Each had a very similar time to trip.
- Each caused a sectionalizing (i.e., not substation) recloser to operate.

Over the past fourteen months, there have been two significant periods of time during which this incipient fault did not manifest itself. However, in each instance the fault eventually did reappear. To date, the utility has not located the underlying problem and it continues to cause intermittent overcurrent faults, voltage sags and momentary service interruptions.

Recorded Data

The "Statistical Processing Module" section of Chapter 4 discusses how the pre-prototype computes statistical information about the numerous parameters that it monitors and how it stores this information in a long-term database. Researchers often use this time-driven database information to graph the maximum RMS values of each of the three phase currents and of the neutral current over significant periods of time (e.g., one or more months). The resulting graph shows an obvious "spike" for each fifteen-minute interval during which one or more overcurrent faults occurred. Figure 5-26 and the three figures that follow it show this information for a typical month, one figure per phase. Then, Figure 5-30 illustrates this information for phase C, the phase of interest for this particular case, for the month of September 2000.

Next, a series of twelve figures illustrates waveforms that the pre-prototype measured during three phase-C overcurrent faults that correspond to several of the "spikes" in Figure 5-30. This series of figures shows several types of waveforms for these three faults:

- Instantaneous substation waveforms (Figure 5-31 through Figure 5-33)
- Instantaneous substation waveforms with steady-state load current removed (Figure 5-34 through Figure 5-36)

- Calculated RMS of the substation current (Figure 5-37 through Figure 5-39)
- Calculated RMS of the substation current with steady-state load current removed (Figure 5-40 through Figure 5-42)

A final series of figures presents the calculated RMS of the substation current with the steady-state load component removed during several additional instances of this event that occurred over the months that followed.

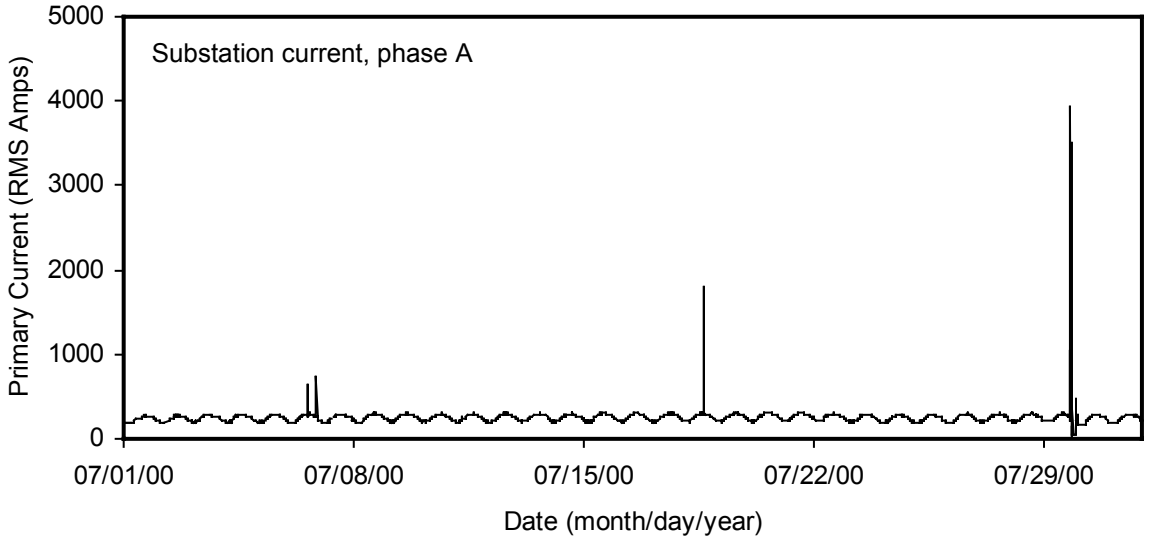


Figure 5-26
Maximum Fifteen-minute RMS Current Readings, Phase A, July 2000

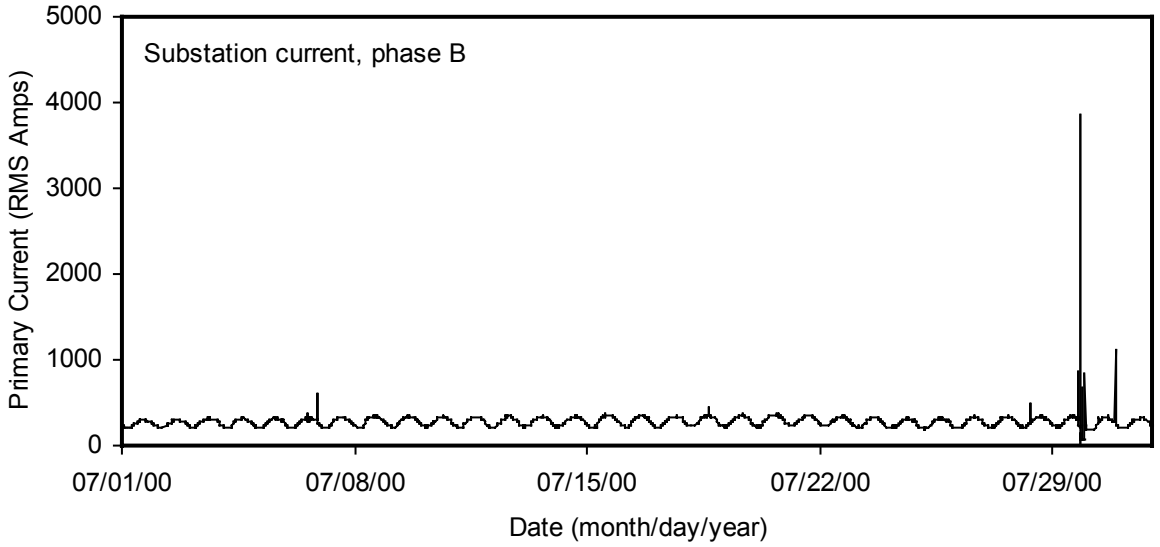


Figure 5-27
Maximum Fifteen-minute RMS Current Readings, Phase B, July 2000

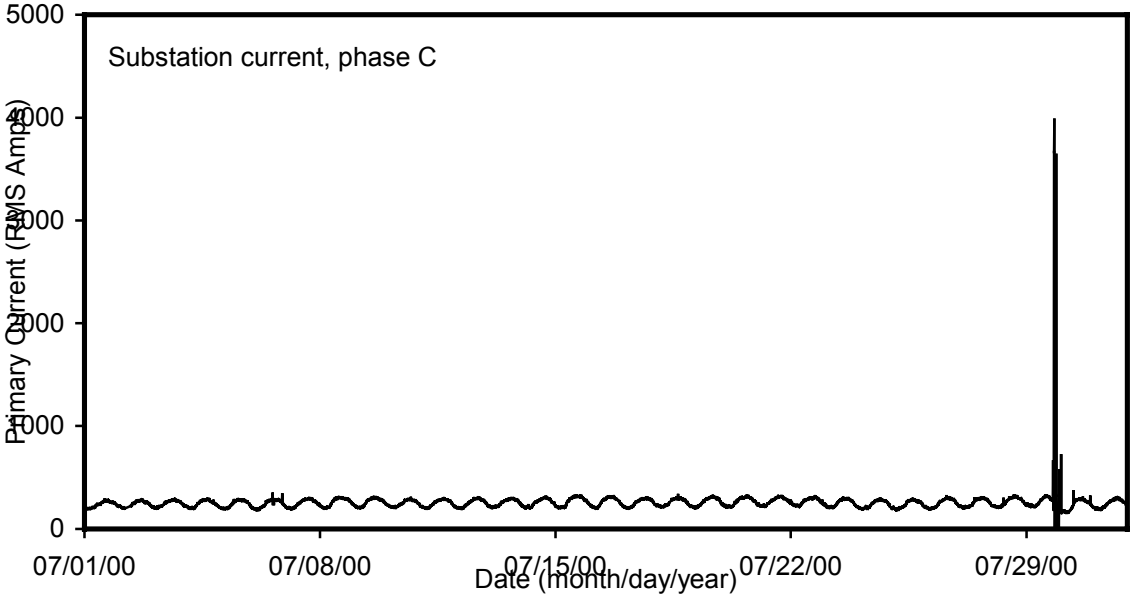


Figure 5-28
Maximum Fifteen-minute RMS Current Readings, Phase C, July 2000

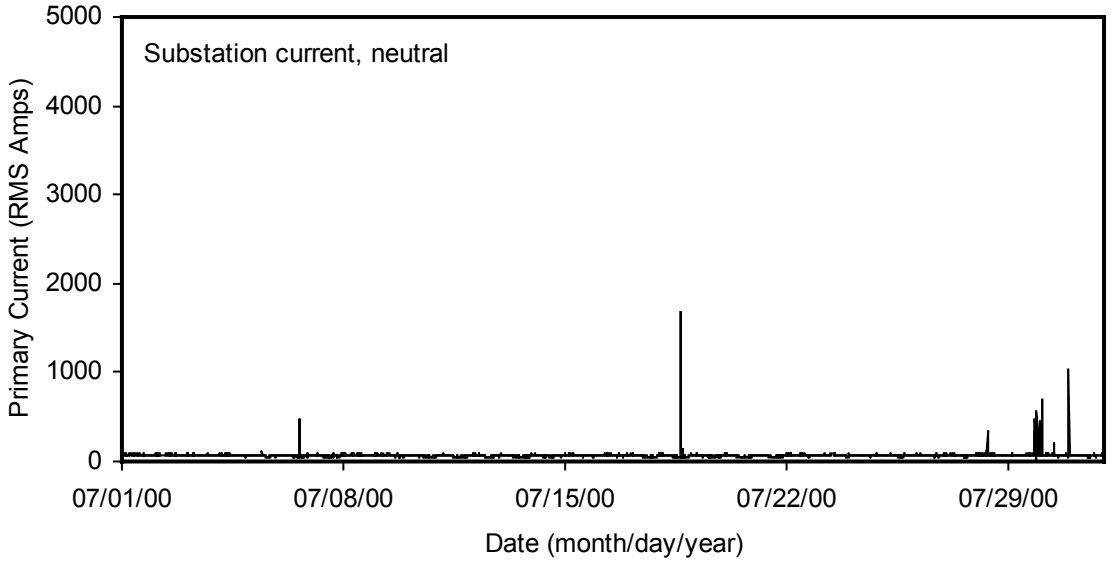


Figure 5-29
Maximum Fifteen-minute RMS Current Readings, Neutral, July 2000

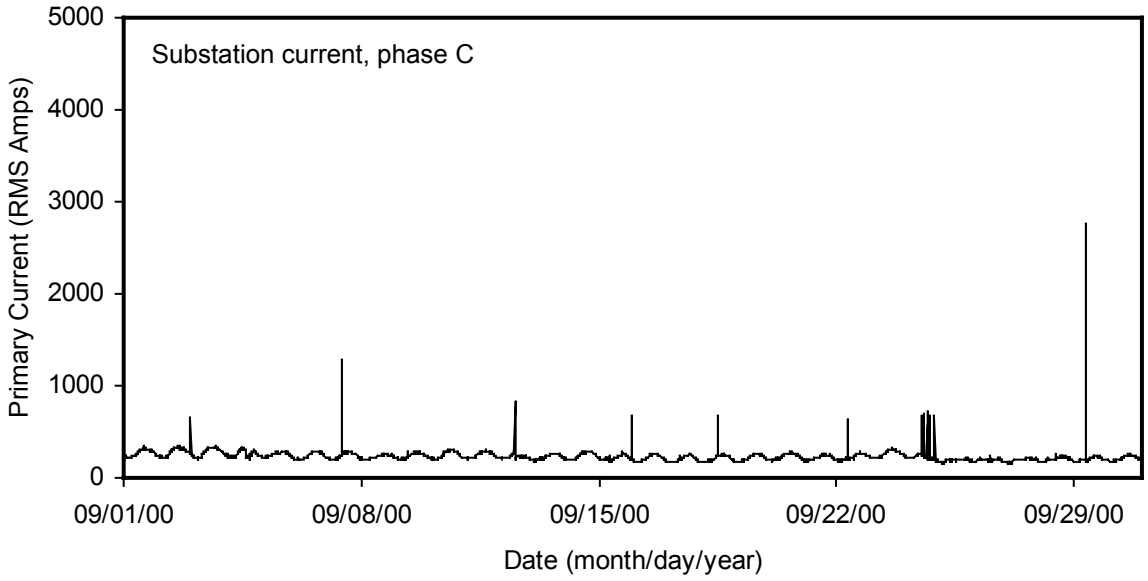


Figure 5-30
Maximum Fifteen-minute RMS Current Readings, Phase C, September 2000

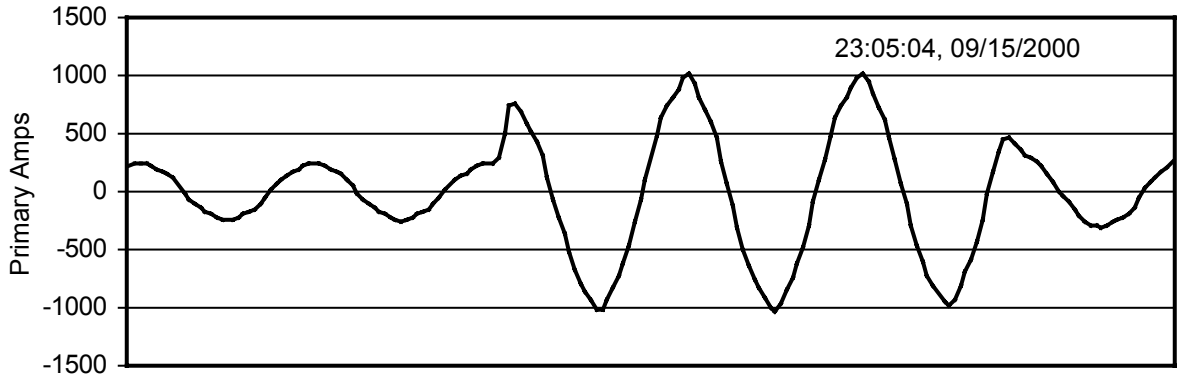


Figure 5-31
Substation Phase Current during First Example of Repetitive Fault

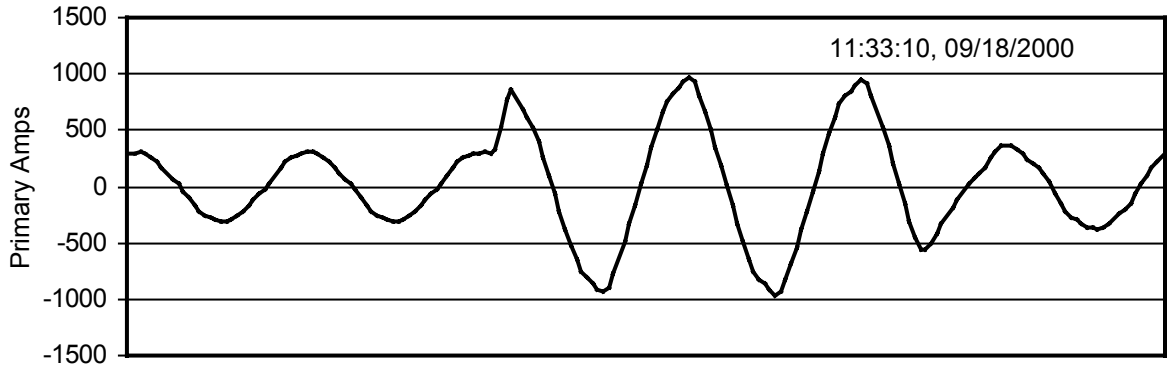


Figure 5-32
Substation Phase Current during Second Example of Repetitive Fault

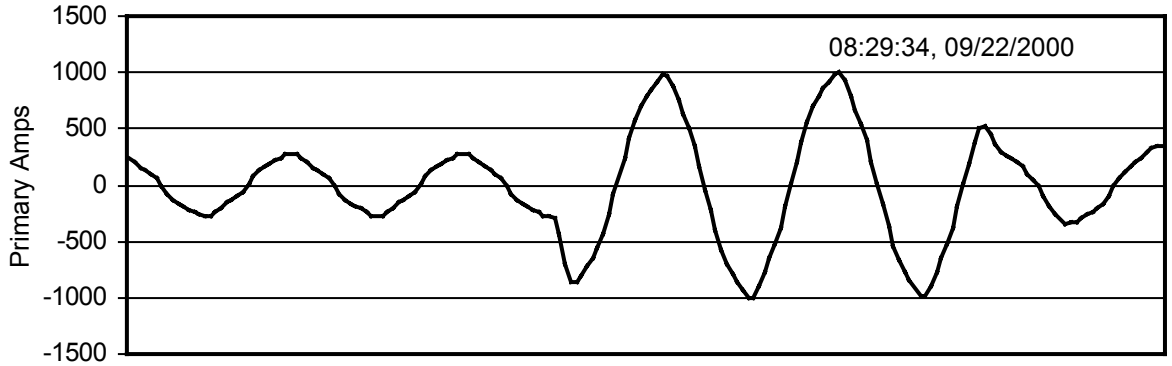


Figure 5-33
Substation Phase Current during Third Example of Repetitive Fault

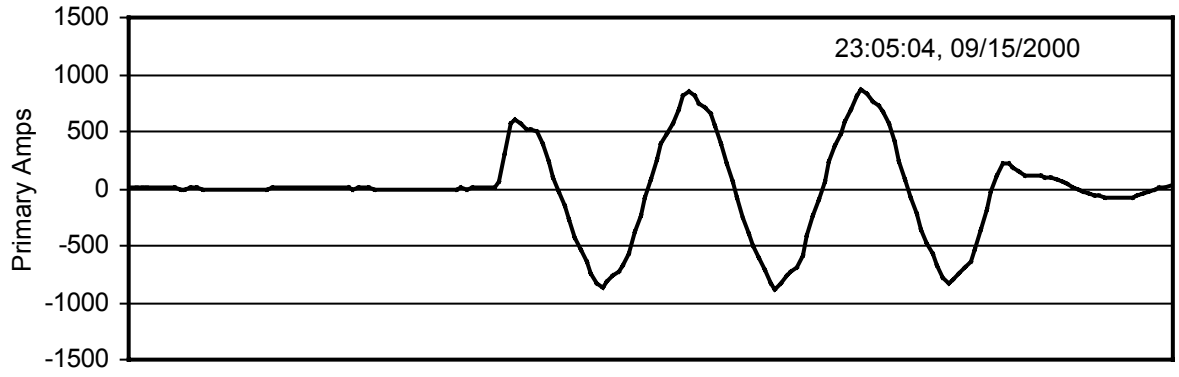


Figure 5-34
Current Waveform of Figure 5-31 with Steady-state Load Removed

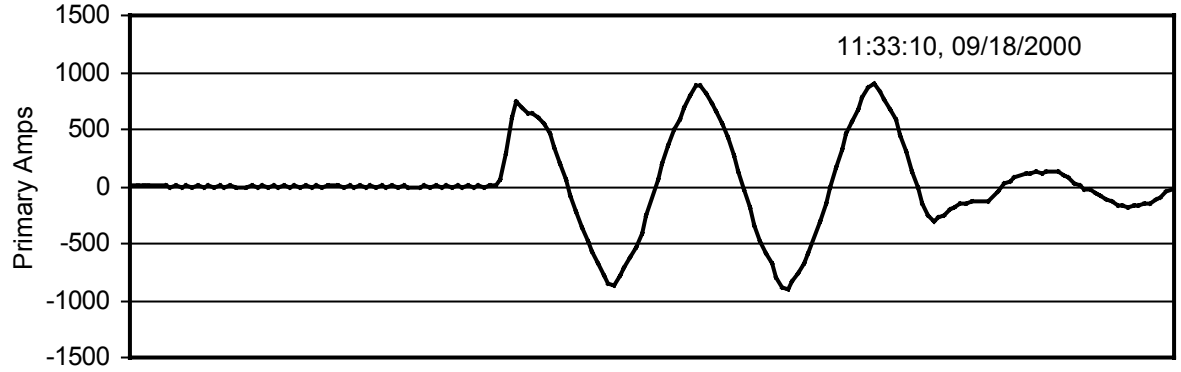


Figure 5-35
Current Waveform of Figure 5-32 with Steady-state Load Removed

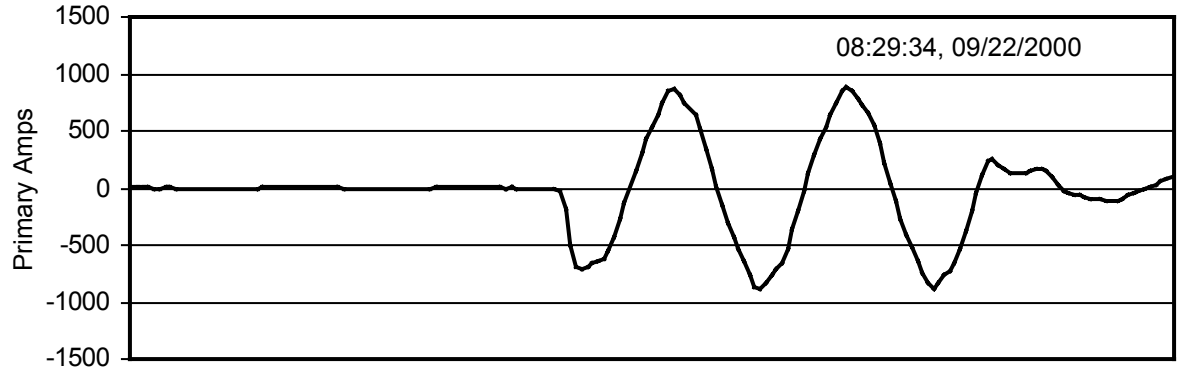


Figure 5-36
Current Waveform of Figure 5-33 with Steady-state Load Removed

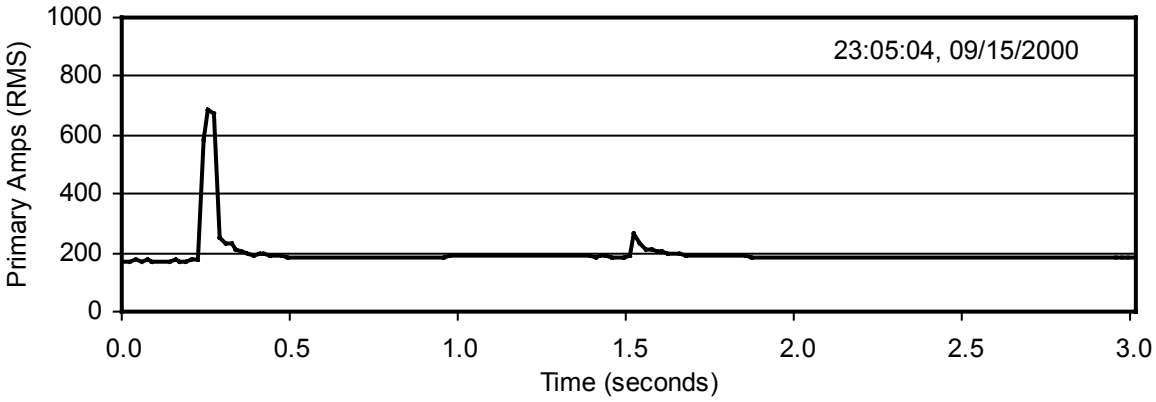


Figure 5-37
RMS Current Corresponding to Figure 5-31

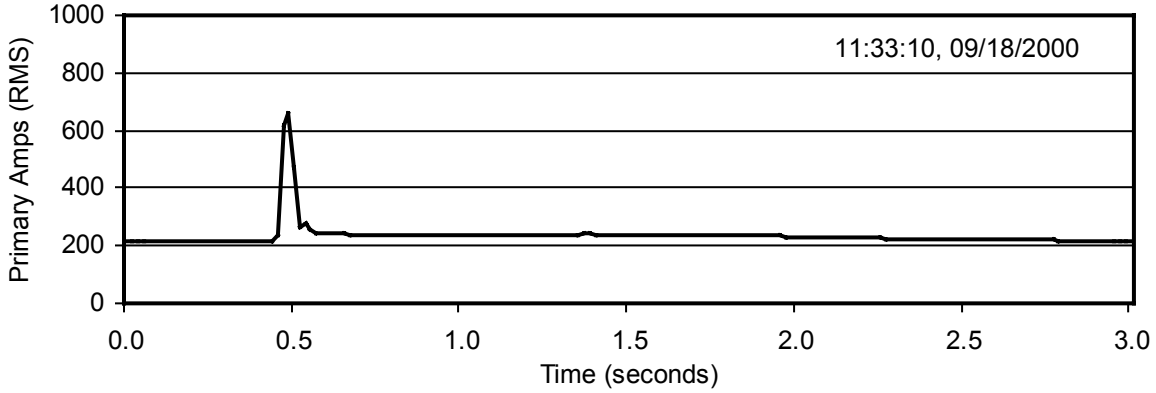


Figure 5-38
RMS Current Corresponding to Figure 5-32

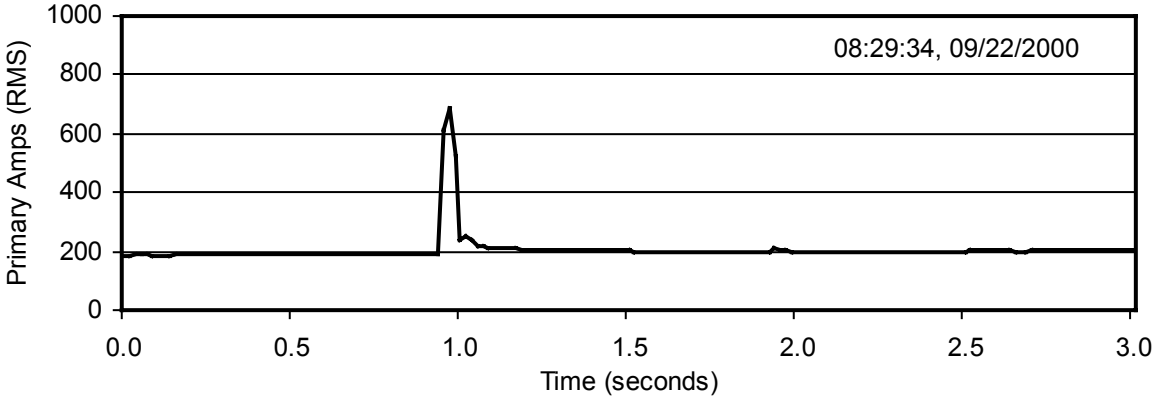


Figure 5-39
RMS Current Corresponding to Figure 5-33

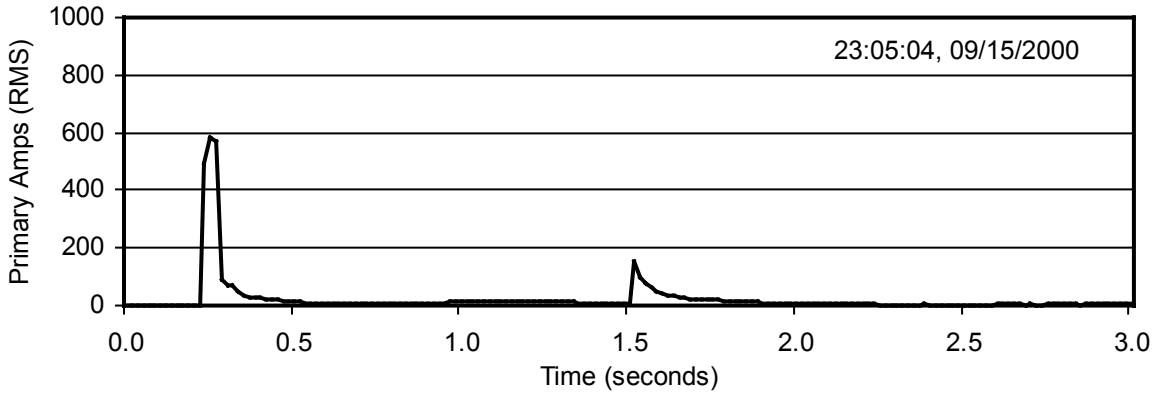


Figure 5-40
RMS Current Corresponding to Figure 5-34 (Load Removed)

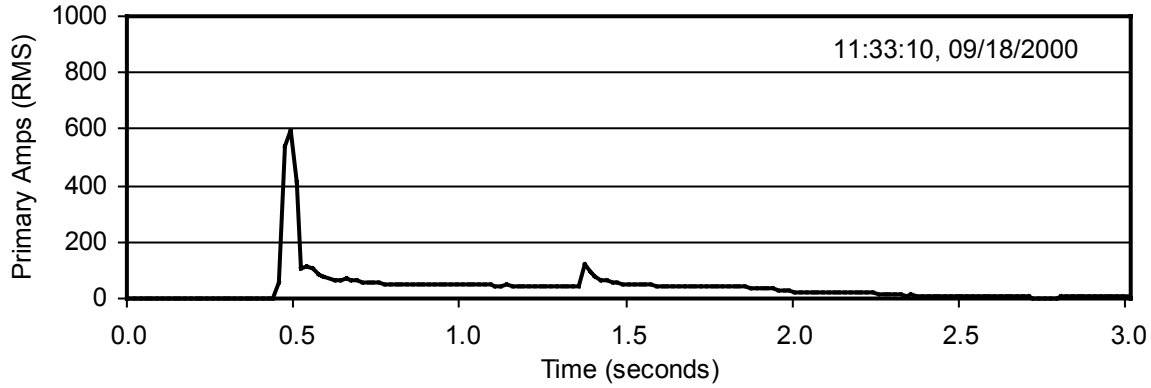


Figure 5-41
RMS Current Corresponding to Figure 5-35 (Load Removed)

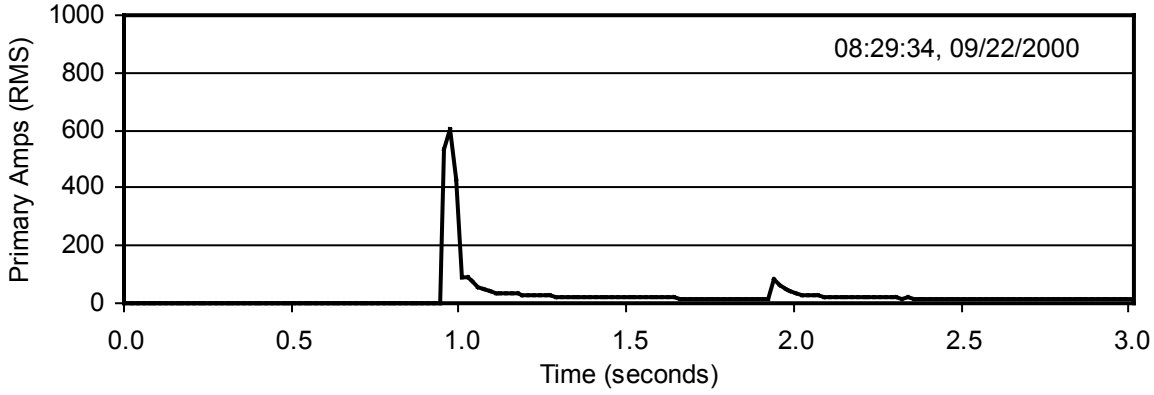


Figure 5-42
RMS Current Corresponding to Figure 5-36 (Load Removed)

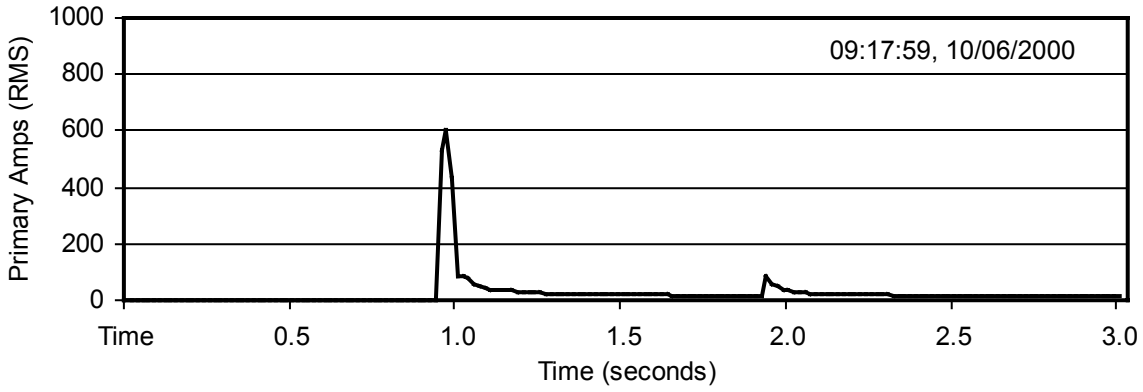


Figure 5-43
RMS Current of Repetitive Event, October 2000 (Load Removed)

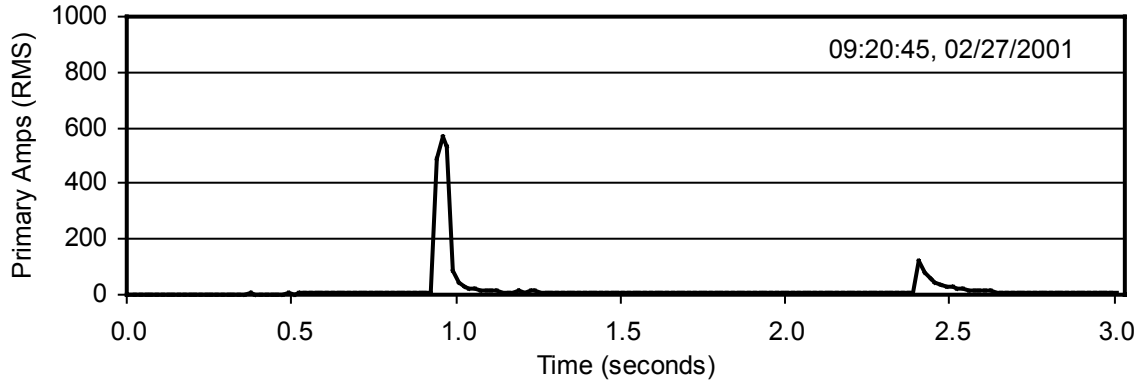


Figure 5-44
RMS Current of Repetitive Event, February 2001 (Load Removed)

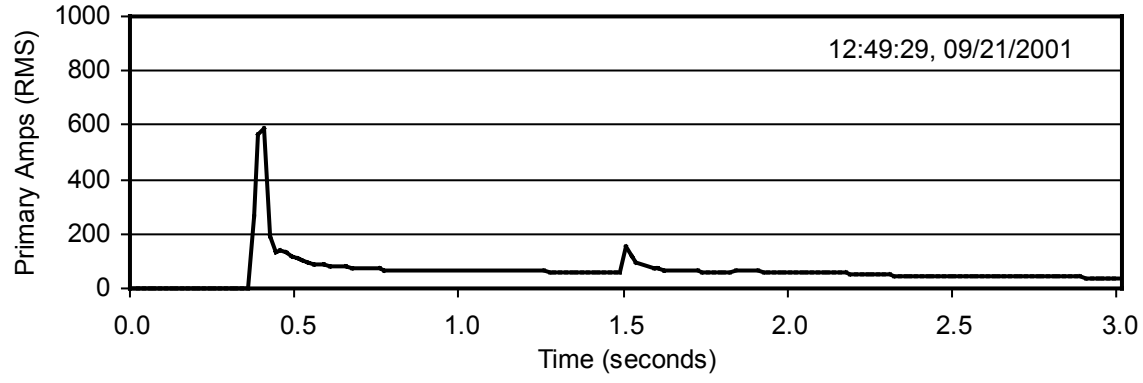


Figure 5-45
RMS Current of Repetitive Event, September 2001 (Load Removed)

Analysis of Recorded Data

The series of four figures beginning with Figure 5-26 illustrates one typical use of the statistical database that the pre-prototype creates and maintains. This series of figures provides the maximum RMS readings for each fifteen-minute interval during the month of July 2000. Each "spike" in the figure is indicative of a fifteen-minute interval in which the pre-prototype measured an abnormally high current level. Such a spike generally occurs because of a fault or a significant inrush transient on the monitored feeder. For example, examination of Figure 5-26 shows two spikes on phase A on July 6, 2000, one on July 18, and several over a period of a few hours on July 29. Similar analyses apply to Figure 5-27 for phase B and to Figure 5-28 for phase C. Figure 5-29 shows the neutral current and provides an estimate of the number of events that involved ground during the month.

In October 2000, research personnel examined this type of high-level statistical information for September (see Figure 5-30). They noted that a large majority of the faults involved phase C. They also noted that the magnitudes of many of these faults appeared to be similar. By examining individual data files, they determined that there had been 23 phase-C-to-ground overcurrent faults during the month. Note that Figure 5-30 shows significantly fewer than 23 spikes. The apparent discrepancy occurs because some of the spikes in the figure represent fifteen-minute intervals in which more than one overcurrent occurred. In such instances the spike in the figure represents the magnitude only of the largest single measurement in the interval.

Figure 5-31 and the two figures that follow it illustrate the phase-current waveforms that the pre-prototype recorded at the substation during three of these phase-C-to-ground faults. Research personnel used the previously described algorithm (see discussion preceding Figure 5-2 for algorithmic details) to remove the steady-state load component from these waveforms and plotted the results in the three figures starting with Figure 5-34. From these figures, one notes that the three events exhibit several marked similarities:

- They all are on the same phase (C).
- They all have similar magnitudes (RMS currents of 587, 596 and 601, respectively, after removing steady-state load).
- Each lasts between two-and-one-half and three cycles.
- In each case, fault initiation begins around the time of the load-current peak.

Figure 5-37 and the two that follow it illustrate RMS substation currents and the series of three beginning with Figure 5-40 show the RMS of these currents after removal of the steady-state load component. These figures represent the calculated RMS values corresponding to the earlier series of six waveforms starting with Figure 5-31. The RMS figures, particularly those without the load component, make it obvious that there is a reclose transient associated with each case.

Based upon these initial observations, the research team examined recorded events from earlier dates and determined that this series of apparently similar events actually began in late August 2000. It seemed unlikely that so many of the faults could share so many characteristics by

coincidence, so they began analyzing the events in more detail, using the following working assumptions:

- That there was an incipient-fault condition somewhere on the feeder.
- That the incipient condition manifested itself from time to time as a momentary overcurrent fault.
- That each time the incipient condition caused an overcurrent, a sectionalizing (i.e., not substation) recloser operated to clear the fault.
- That when the recloser closed back in, the fault healed temporarily so that the recloser did not operate to lockout.
- That the recloser operation temporarily cleared the fault but did not cure the underlying cause.

As an aside, at this point it should be noted that the host utility associated with this case has not had the opportunity to investigate this incipient fault. This is unfortunate for at least two reasons. First, the problem continues to cause voltage sags, momentary interruptions, etc. for customers on the affected feeder. Second, it is impossible to provide complete closure for this case study without knowing the diagnosis. However, there is a silver lining from a research perspective. At the time of the writing of this report, this event has been present on the feeder for well over a year, intermittently causing faults. In the process, it has provided a very substantial database of fault records for study. In fact, this feeder has produced 144 phase-C-to-ground faults over a period of fourteen months, a large number of them apparently related to a common incipient condition. The following paragraphs discuss the analysis of these faults in greater detail.

Figure 5-46 illustrates a histogram of the magnitudes of the 144 phase-C-to-ground faults that the pre-prototype measured during the fourteen-month period. The height of each column in the figure represents the number of these faults that falls in any particular 25-ampere range. The immediate observation from this graph is that the vast majority of the faults fall between 500 and 650 amperes. More precisely, it appears that a large number of them fall into two clusters. The first ranges from 501 to 550 amps and contains 36 (25%) of the 144 faults. The second ranges from 576 to 625 and contains 71 (49%) of them. In other words, 36 of these faults produced 525 +/- 25 amps and 71 other faults produced 600 +/- 25 amps. Obviously, there is little chance that this is coincidence. Apparently, an incipient-fault condition is causing these repetitive overcurrents. Alternatively, it is possible that there are two incipient faults on this circuit, one causing the 501- to 550-amp faults and the other causing the 576- to 625-amp faults. The research team has proceeded on the assumption of only one incipient-fault condition but recognizes that it is possible that two actually exist.

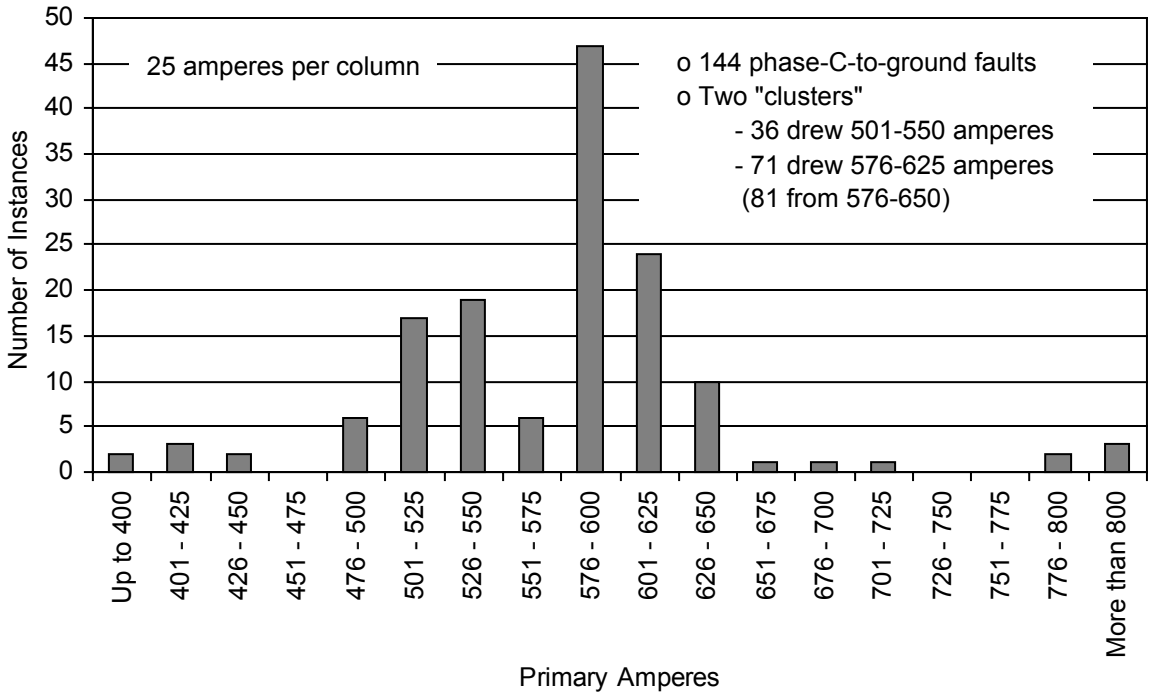


Figure 5-46
Histogram of 144 Phase-C-to-ground Fault-current Magnitudes (Steady-state Removed)

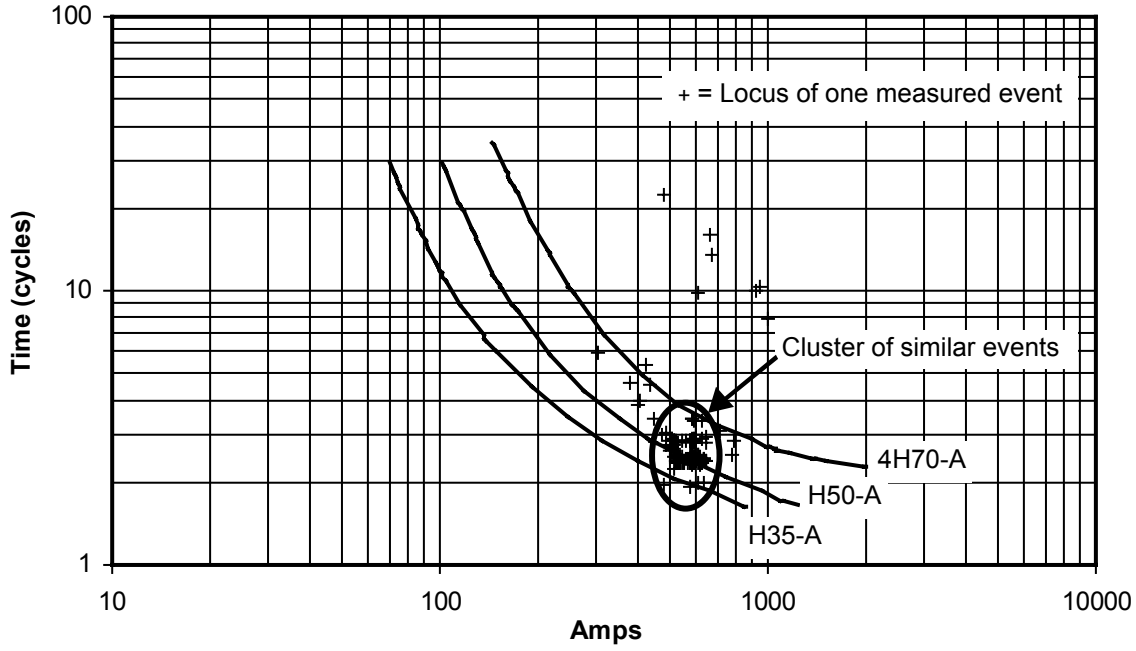


Figure 5-47
Loci of 144 Phase-C Line-to-ground faults (Steady-state Current Removed)

Figure 5-47 shows the time-current coordinates of these 144 faults. Each '+' symbol in the figure represents the locus of one measurement. The X coordinate of each '+' represents the measured amplitude of the phase current with its steady-state load component removed. The Y coordinate represents the duration of the fault, measured in cycles. The circled region in the figure indicates a readily evident clustering of the events. This suggests even more strongly that many of the events have a common underlying cause.

Texas A&M University's researchers further examined the calculated RMS of the phase current with its steady-state component removed, now looking more closely at the time period after the fault cleared. In each of the six figures starting with Figure 5-40, the presence of a reclose transient approximately one second after the fault cleared is quite apparent. Obviously, this means that each fault must have occurred downstream of a recloser. Therefore, the research team sought more information about the reclosers on this feeder.

They learned from the host utility that there are fifteen hydraulic reclosers on this feeder, consisting of six distinct ratings. They obtained the time-current characteristic (TCC) curves for each rating and compared them to the measured currents and trip times of the 144 phase-C-to-ground faults. The TCC curves of the three trip ratings that most closely match the loci of the vast majority of the measurements are superimposed on Figure 5-47. For faults that required the recloser to trip more than once, the figure shows only the locus of the interval related to the first trip. Accordingly, the figure shows only the "A" curve of each recloser. In reality, each recloser was configured to trip twice on its fast "A" curve and twice on its time-delayed "B" curve before locking out. However, most of the measured instances of the fault required only one trip in order to heal the fault temporarily, so the research team concentrated most of its attention on only the first trips, even in multi-shot events.

Figure 5-47 clearly demonstrates that a majority of the measured faults' I-t values cluster closely around the "A" curve of the H50 recloser. This suggests that the most likely location of the incipient fault would be downstream of an H50 recloser on the monitored feeder. As it turns out, only three of the fifteen hydraulic reclosers on this feeder are of the H50 type. This greatly reduces that portion of the feeder that the utility would need to search in an attempt to find and correct the problem.

The researchers then investigated one additional characteristic from these faults: the amount of time the recloser stayed open before restoring service. According to the host utility, the manufacturer of the hydraulic reclosers on this feeder sets the first open interval to a period of one second at the factory. The utility's ability to change this interval is limited: they can leave it set to one second or they can change it to two seconds. In this case, the utility left all of its hydraulic reclosers' open intervals set to one second.

The research team examined the multitude of recorded events once again in an effort to evaluate the consistency of the measured open intervals. They found the intervals' variation to be larger than they expected, so they contacted a representative of the reclosers' manufacturer to discuss the discrepancy. He was not particularly surprised by the variation and stated that temperature can affect open intervals significantly. He said that he knew of internal test sheets that quantified this effect and stated that he would attempt to obtain this quantitative information and provide it

to Texas A&M personnel. However, several months have elapsed between that conversation and the time of this writing, during which time the manufacturer's representative has provided no further information.

Customer Complaint

Shortly after recognizing the presence of this intermittent incipient fault, research personnel contacted the host utility to discuss it and to provide information for a potential search. Utility personnel recalled receiving a customer complaint around the time the intermittent faults began to occur.

The complaining customer operates a convenience store that has electronic cash registers that were resetting themselves intermittently. Assuming that the source of the problem was the electricity supply, he contacted the utility company.

The utility visited the customer's location to determine more information about his problem. As a result, they initiated a search for the underlying cause. However, the search was unsuccessful.

The customer stopped complaining after several weeks, but the utility believes that the customer took the initiative to install an uninterruptible power supply (UPS) for his sensitive equipment. Therefore, it is likely that the underlying power-system problem is still present but mitigated by the prudent action of the customer.

No one knows for sure whether this customer's problem is related to the repetitive fault that the pre-prototype has measured but the fault certainly may have been the culprit. The additional information that the pre-prototype system has provided may justify a renewed search effort. Certainly the wealth of information from the system improves the chances of success. Perhaps the utility will be able to undertake this in the future.

Case Discussion

It is unfortunate that the host utility in this case did not have an opportunity to search for this incipient fault, because this lack of information prevents proper closure of the case. Even so, this case demonstrated the potential of using on-line monitoring to detect this category of incipient faults: intermittent, repetitive, overcurrent faults.

Automated location of faults on distribution feeders is difficult. The intermittence of this type of incipient fault makes its location all the more difficult. However, this case suggests that utilities could narrow the search area significantly by using information from the pre-prototype data collection system. Specifically, comparing the recorded data with the known operating characteristics of the protective devices on the feeder strongly suggests searching only in areas downstream of matching devices, in this case downstream of one of the three H50 reclosers on the monitored feeder.

The utility could choose to pursue at least one other means of further narrowing the search area, although it would require additional effort on its part. If practical, the utility could visit one of the three H50 reclosers and temporarily change the duration of its open interval from one second to two seconds. Changing the open interval in this way should not affect feeder coordination. After the utility changes the open interval, Texas A&M's research team could continue to monitor for future occurrences of the repetitive fault. If future measurements showed a change in the open interval following the overcurrent faults, the utility would know that they had identified the recloser protecting the point of the incipient fault. If the measurement interval did not change, the utility could change the open interval of one of the two remaining H50 reclosers and follow a similar procedure for determining if the incipient fault's cause was downstream of that recloser. Once this was done, the remaining search area would be relatively small. The majority of the cost associated with following this procedure would be the labor associated with changing the intervals. Texas A&M leaves it to the utility to determine the practicality and value of pursuing such a course of action.

This case also demonstrated the potential to use on-line monitoring to improve power quality. As in the previous case, each time this incipient fault caused an overcurrent, it caused at least two deleterious effects to customers. Most obviously, it caused a momentary interruption to all customers downstream of the recloser that cleared it. In addition, each overcurrent caused the voltage to sag across the entire feeder and, to a lesser extent, across all other feeders emanating from the same substation bus.

At the substation, each overcurrent produced relatively small voltage sags, on the order of ten to fifteen percent for up to three cycles. These sags do not violate the ITIC sag-tolerance curve in Figure 5-25. However, one easily can extrapolate to cases in which the incipient fault location is closer to the substation. Closer faults likely would cause deeper sags. Further, if the protective device that cleared the fault had a higher rating and thus operated more slowly, the duration of the sag would be longer. In short, it is not difficult to imagine slightly different circumstances that would cause repetitive violations of the sag-tolerance curve and the resulting failure of connected equipment.

Finally, one must recognize that even in the present case, locations between the substation and the fault point experience sags that are proportionally deeper than at the substation. Therefore, it is likely that even in this case, those customers located between the substation and the fault point are experiencing significantly deeper sags.

Information from on-line monitoring has the potential to identify this type of problem in relatively short periods of time, allowing utility companies to effect repairs and avoid future sags, interruptions and outages. In addition, such information provides many clues as to the location of the underlying incipient condition. Texas A&M still hopes to have final resolution of this case at some point in the future.

Capacitor Switch Chatter

Case Summary

By design, the pre-prototype data collection systems captured many normal system events, the most common of which resulted from the switching of VAR-compensation capacitor banks. Texas A&M University's research team expected this because of their data-collection philosophy, which intentionally sought to miss no events of interest, even though this necessitated recording, retrieving and analyzing many normal system events (see section entitled Data Collection Philosophy in Chapter 4 for more details).

Capacitor-switching events cause both transient and steady-state parametric changes, making their recognition relatively straightforward. In addition, capacitor-bank controllers often use time-of-day as one of their parameters. Thus, the fact that a particular event happens at or near the same time each day provides further indication of a time-controlled event such as capacitor switching.

Several months after its installation, one of the pre-prototype data collection systems began to capture waveforms that appeared to indicate routine daily capacitor switching. Normally, this would indicate the need for no further analysis. However, the research team noted unusual patterns in these particular waveforms. Specifically, the phase voltages in these measured events did not exhibit normal singular step changes. Instead, the phase voltages stepped up and down multiple times over a time interval of one or more seconds. Further, sometimes all three phases would step "cleanly" while at other times one or more phases had to step up and down multiple times before apparently "latching in."

The researchers reported this to the host utility, which in turn searched for and found the cause. The utility determined that the switch contacts of a time-based capacitor controller were chattering. The utility then switched the controller from automatic mode to manual mode so that the switch contacts would receive no further wear until a crew could service them.

Researchers made a second interesting observation from this particular capacitor bank case. The bank was supposed to switch on at about 7:00 AM each day, but in fact it was switching around 3:20 AM each day. Then, after an unrelated fault caused an extended outage, the switching time changed to around 10:45 AM each day. Shortly thereafter, another unrelated outage caused the switching time to change to 11:25 AM each day. When the utility found the capacitor bank with the chattering switches, they corrected its controller's real-time clock so that when automatic operation resumed, it would switch at the correct time each day.

Recorded Data

The pre-prototype data collection system at one of the host utilities began to record momentary disturbances around 3:20 AM each day, beginning October 19, 2000. Researchers initially noticed this as a small "spike" in the neutral current at the same time each day. In order to capture more detailed information about this event, they increased the sensitivity of the system's

data-capture triggers on November 9, which caused the system to begin capturing high-speed waveform data. Figure 5-48 illustrates the RMS voltages that the system recorded during this first captured event.

Over the next several months, the system recorded many instances of this apparent capacitor-switching event. The event did not cause a disturbance sufficient to initiate a capture each day, but it did so approximately one day out of every two. The next series of figures illustrates these data captures on selected days over the time period between November 2000 and February 2001.

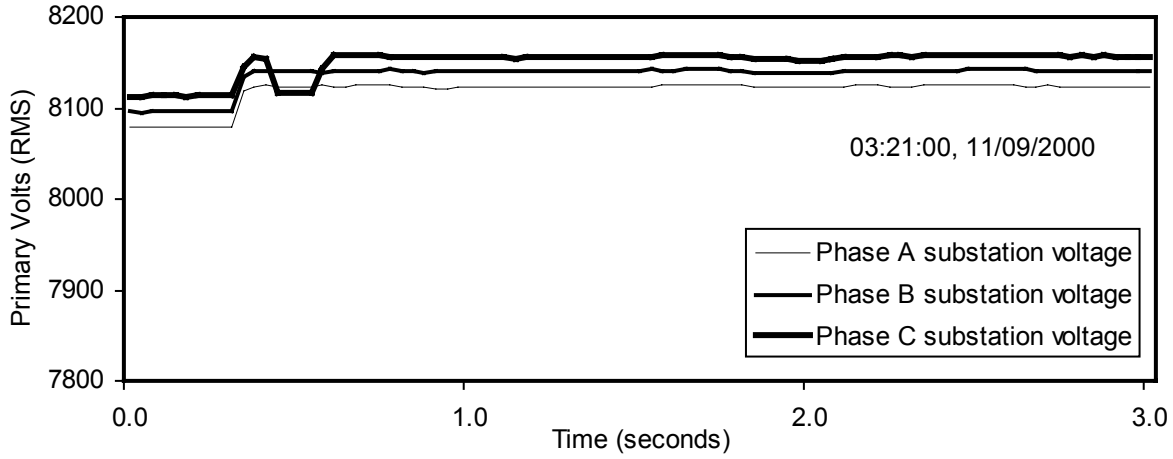


Figure 5-48
First Recorded Instance of Capacitor Bank Switch Chatter, November 9, 2000

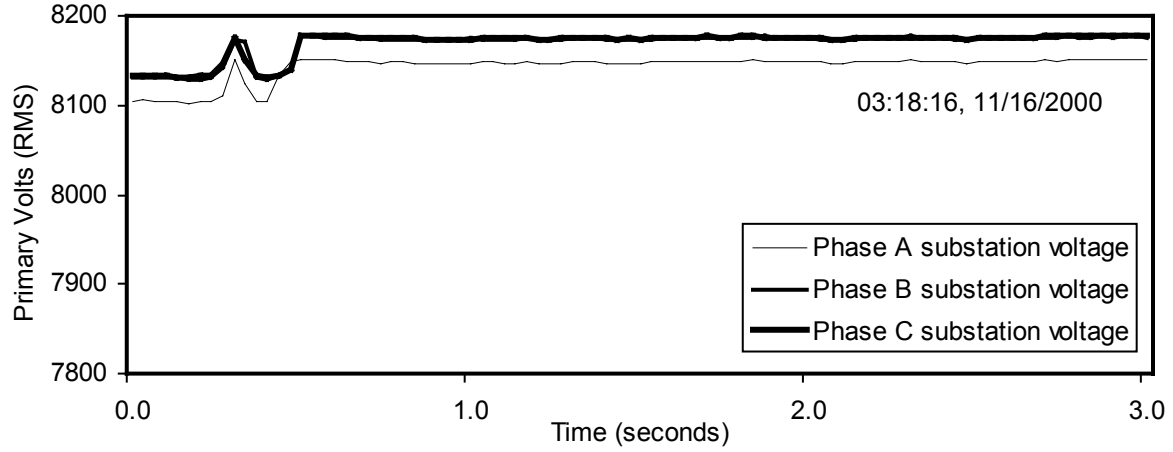


Figure 5-49
Capacitor Bank Switch Chatter, November 16, 2000

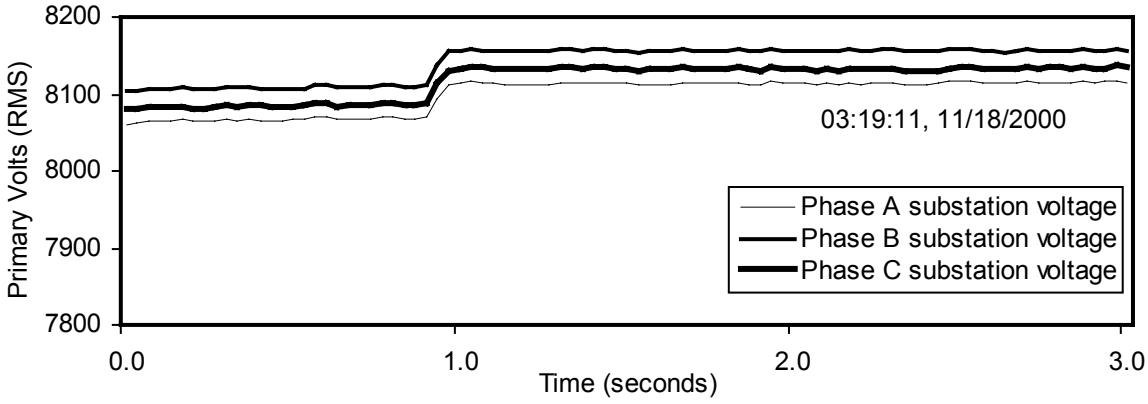


Figure 5-50
Capacitor Bank Switch Chatter, November 18, 2000

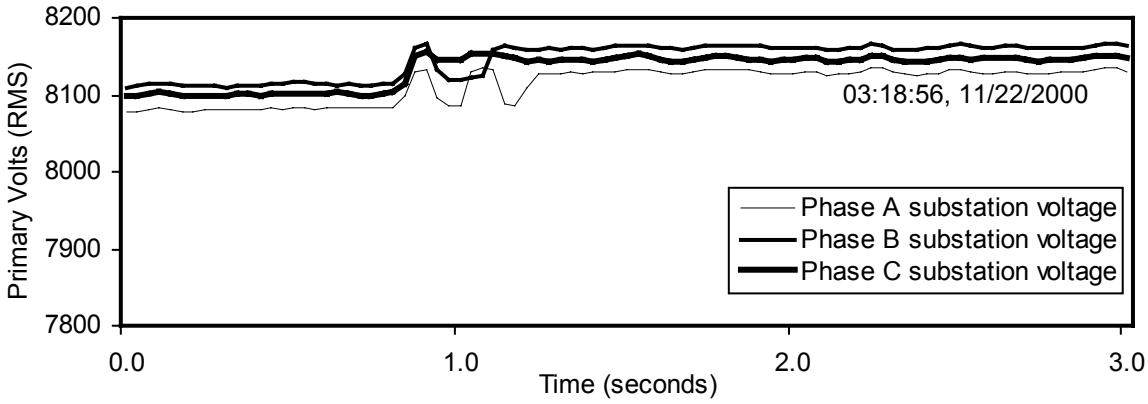


Figure 5-51
Capacitor Bank Switch Chatter, November 22, 2000

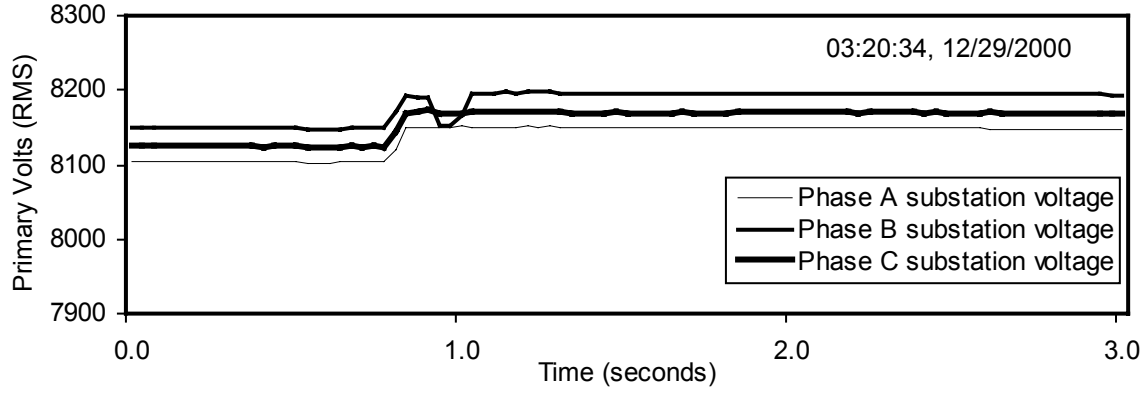


Figure 5-52
Capacitor Bank Switch Chatter, December 29, 2000

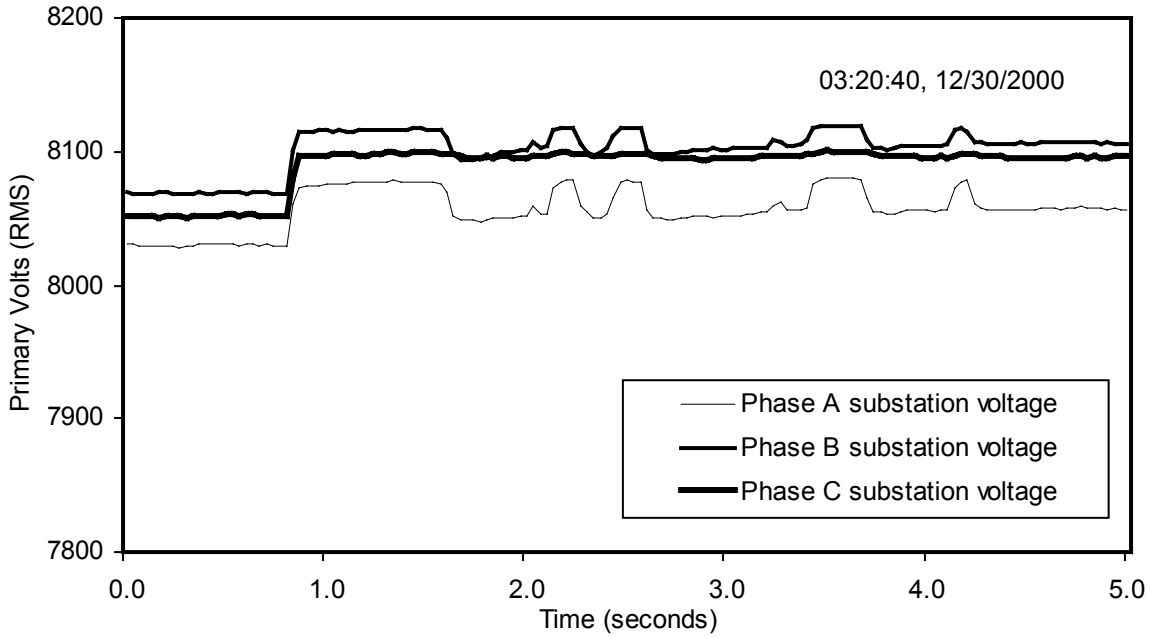


Figure 5-53
Capacitor Bank Switch Chatter, December 30, 2000

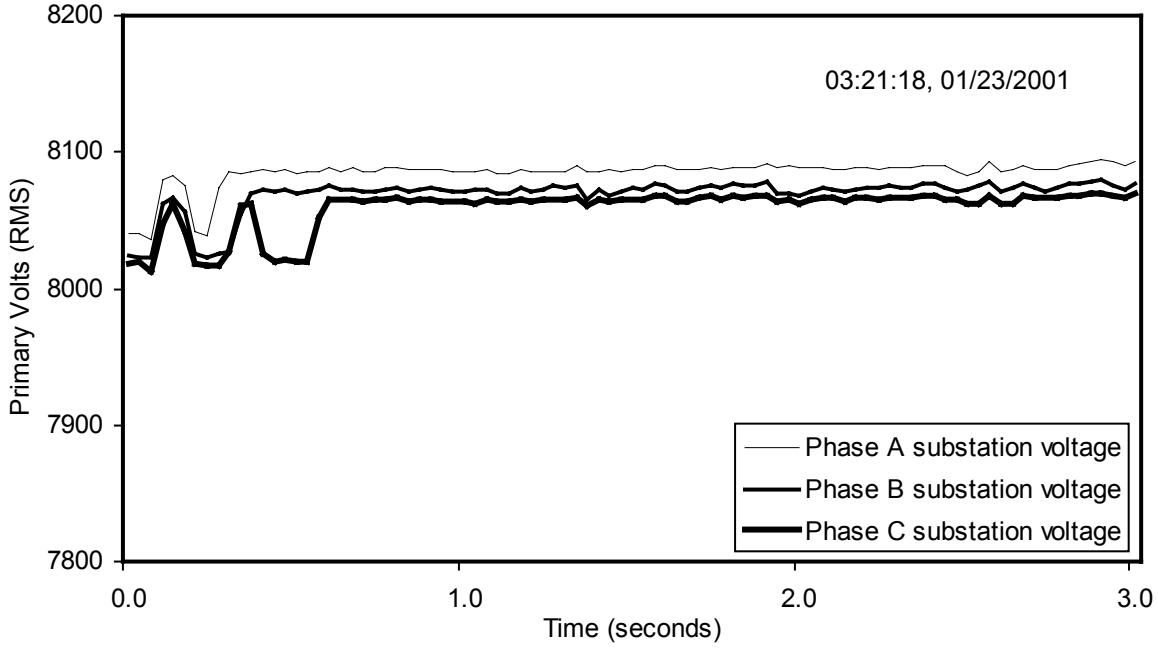


Figure 5-54
Capacitor Bank Switch Chatter, January 23, 2001

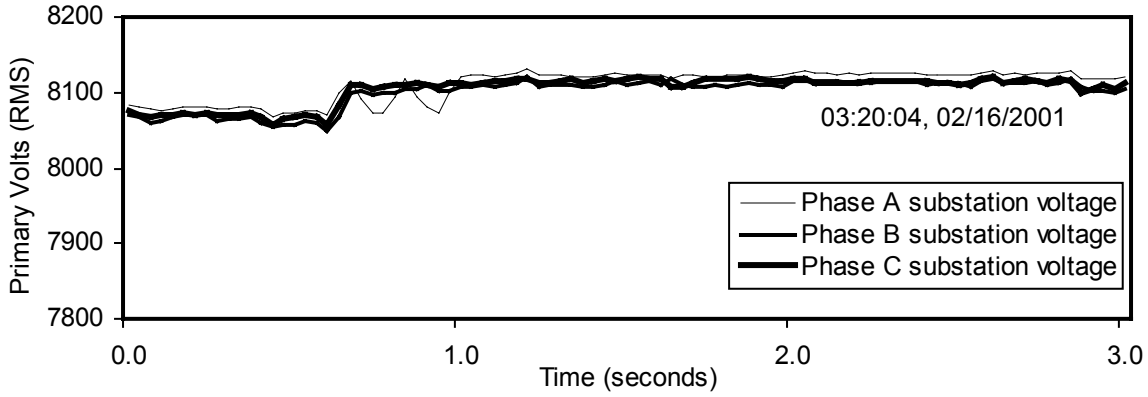


Figure 5-55
Capacitor Bank Switch Chatter, February 16, 2001

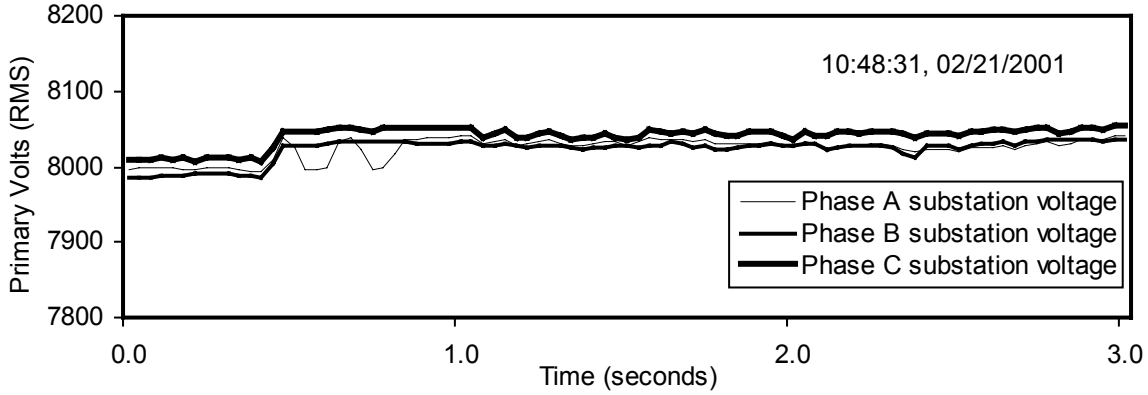


Figure 5-56
Capacitor Bank Switch Chatter, February 21, 2001

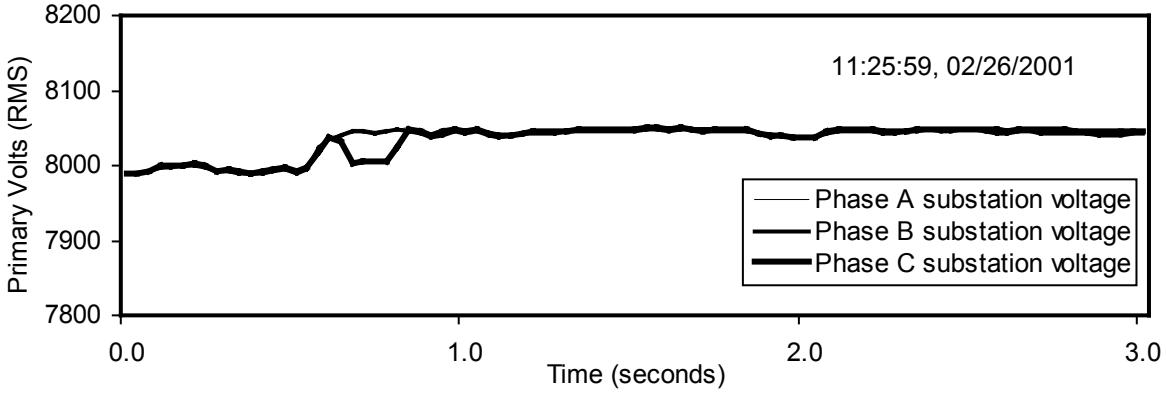


Figure 5-57
Capacitor Bank Switch Chatter, February 26, 2001

Analysis of Recorded Data and Utility Response

Each of the preceding figures illustrates one measured instance of the event. The number of examples presented may seem excessive, because at first glance they appear to present multiple identical measurements. However, the large number of illustrated events demonstrates a number of subtle differences between many of the instances, including the following.

- At some time during the multi-month duration of this case, each phase exhibited multiple steps at least some of the time (e.g., Figure 5-55 shows a multi-step event on phase A, Figure 5-52 on phase B, and Figure 5-48 on phase C).
- On some days, all three voltages stepped cleanly (e.g., Figure 5-50).
- On some days, all three phases exhibited multiple steps before achieving steady state at the higher voltage level (e.g., Figure 5-49).
- On some days, two phases exhibited multiple steps (e.g., Figure 5-51).
- On some days, only one phase exhibited multiple steps (e.g., Figure 5-56).
- On some of the days on which multiple phases showed multiple steps, not all of these phases had the same number of steps (e.g., Figure 5-54).
- Figure 5-53 illustrates the "worst" case of this event. In this example, two of the phase voltages stepped at least four times over a period of at least five seconds. Note that at the end of the period shown in the figure, these two voltages still have not "locked in." The recorded data do not make it possible to determine how many times these two phases stepped or how long this took.
- After an extended forced outage, the time-of-day at which the events occurred suddenly changed on February 21, 2001, from 3:20 AM to 10:48 AM. This was a sudden change of more than seven hours (compare the time of Figure 5-56 to that of Figure 5-55).
- After another forced outage, the time-of-day at which the events occurred suddenly changed again starting February 26, 2001, this time from 10:48 AM to 11:25 AM (see Figure 5-57).

The above list demonstrates differences between instances of the event. However, there were certain consistencies in the measurements as well:

- The magnitude of the change was fairly consistent. Each phase voltage stepped up by between 0.52 and 0.59 percent each time the event occurred.
- The event obviously was tied to a real-time clock. For over three months, the event occurred every day at 3:20 AM, plus or minus a few minutes. Then, the time of occurrence suddenly changed by more than seven hours. Following this, there was a new consistent time of occurrence. Approximately one week later, the time changed again and again established a new consistent daily time of occurrence.
- Each time the event occurred, it caused a transient in the voltage waveform. The transient's frequency was several hundred Hertz and was time-limited to a fraction of a cycle, typically around one-quarter of one cycle.
- The event caused no precipitous change in VAR flow.

It is obvious that the underlying cause of the event is a time-controlled device that causes a small (i.e., less than one percent) but precipitous voltage change on a three-phase basis. Texas A&M's research team discussed two possibilities with the host utility: 1) a capacitor bank switching and 2) a load tap changer operating.

The researchers compared the pre-prototype's measurements with information that the utility provided about the tap changer at the substation bus. They found three inconsistencies that made the tap-changer diagnosis unlikely. First, the magnitude of the voltage step was incorrect. The tap changer's rated step size is five-eighths (0.625) of one percent per step. By contrast, the measured changes were as small as 0.52 percent. The difference seems small but is undeniable nonetheless. Also, if the tap changer were responsible for the events, the magnitude of the change should have been very consistent from day to day, but the measured data revealed that the magnitude of the changes varied from 0.52 to 0.59 percent. Finally, the tap changer's control circuitry operates only when the magnitude of the bus voltage moves outside a pre-defined range and its operation is not dependent on time-of-day. Therefore, it was inconceivable that the measured time-of-day would be so consistent if time were not a control parameter.

The other possibility, capacitor bank switching, seemed more likely. First, it is common for capacitor controllers to use time-of-day as a control parameter. Second, capacitor switching causes time-limited voltage transients in the observed frequency range of several hundred Hertz.[6] Further, none of the observations contradicted this diagnosis. The only parameter that normally changes when a capacitor switches but that did not change during the measured events was VAR flow. After all, one of the primary purposes of a feeder capacitor bank is to reduce VAR flow, but this event did not cause any appreciable VAR change. Therefore, the measurements are not characteristic of a capacitor bank switching, at least not one on the monitored feeder. However, the observed data do fit the characteristics one would expect when a capacitor switches on an adjacent feeder that emanates from the same bus as the monitored feeder: at the same time each day, each phase voltage steps up, the voltage shows a brief high-frequency transient, and there is little change in VAR flow. Therefore, all known evidence indicated a capacitor bank on an adjacent feeder as the most likely cause.

In many ways, the recorded events are unremarkable. Capacitors switch every day on a huge number of distribution feeders. What is of interest and possible concern in this particular case is that the phase voltages do not simply step up and stay there. Rather, in many cases they step up, then down, then back up and so on, sometimes going through several such cycles before staying at the higher level. Obviously, this is abnormal.

Researchers provided all known information about the event to the host utility company, which then initiated a search for the cause. The substation bus that serves the monitored feeder serves a total of eight feeders. Because all feeders will share any voltage step that an event on any single feeder causes, the first step in finding the cause was to determine the appropriate feeder. The utility selected one of the feeders at random and temporarily switched its load to an alternative bus in the same substation. The intent was to determine whether the voltage-step event continued to occur. If it did, it would mean that the cause was not on the selected feeder.

After switching the first selected feeder to another supply, the utility waited while the pre-prototype data collection system continued to monitor the original feeder. The voltage-step event did occur at the usual time the next day, which indicated that the cause was not on the switched feeder. The utility switched that feeder back to the original bus and selected another feeder to switch temporarily to the alternative source.

The voltage-step event did not stop when the utility switched the first, the second, or the third feeder to the alternative source. However, when the utility switched the fourth feeder to the alternative source, the pre-prototype data collection system stopped seeing the voltage-step event. The researchers and the utility waited until they had failed to see the event for several consecutive days before concluding that they had identified the correct feeder. For further confirmation, the utility switched the feeder back to the original bus. As expected, the voltage-step event returned.

Having identified the offending feeder, the utility looked for time-controlled capacitor banks on that feeder. They found that the feeder did have such a capacitor bank. They changed the controller's operation from automatic (i.e., timed) to manual, leaving the bank permanently switched on. After they did this, the pre-prototype stopped registering the daily events, indicating that they had identified the correct piece of equipment.

The utility was unsure whether this apparent contact chatter was cause for concern but they planned to leave the controller in its manual state until a crew could schedule time to test and, if appropriate, repair or replace the switch. Texas A&M awaits the outcome of this testing and maintenance activity.

Case Discussion

This case demonstrated the ability to use real-time monitoring to distinguish abnormal switching characteristics from normal ones and the potential to anticipate future failures in switching equipment. It points out the need to recognize normal system events and the need to recognize when such events are displaying characteristics that are outside normal operating conditions.

Capacitor banks and their controls are simple devices, but they are important to optimal power-system operation. They provide VARs to serve the needs of motor loads, thereby freeing generated volt-amperes to serve additional real-power loads. In so doing, they have a very significant effect on the economic operation of the system. There is much anecdotal evidence to suggest that it is quite common for capacitor banks to fail to operate correctly. It is possible that identification of the chattering contacts of the switch controlling this capacitor bank averted such a situation. Further, had the contacts failed, it is uncertain whether they would have done so by catastrophically destroying the switch or simply by failing to switch the capacitor bank on its daily cycle. In the latter case, the capacitor could have failed to operate for a long period of time, perhaps months, before the utility became aware of the condition.

There has not yet been full closure for this case study but the utility has scheduled an investigation and, if needed, repair of the chattering contacts. It is unknown whether the chattering constituted a problem that should cause the utility company concern. However, the

sudden onset of the chattering would make it seem likely that there is reason for concern, because sudden changes in mechanical apparatus seldom are harmless.

Further to the above, contact chattering generally involves arcing as the contacts make and break multiple times. This arcing is likely to lead to pitting of the contacts, which in turn is likely to worsen the bouncing and arcing. This represents a vicious cycle in which the contacts degrade progressively over time. The logical conclusion is that this eventually would have led to one of two possible consequences, neither of them positive. In one scenario, it simply could cause the switch to stop making contact, thereby inhibiting proper operation of the switch and the capacitor bank itself. Alternatively, the pitted contacts easily could develop hot spots that could lead to destruction of the entire switch assembly, which likely would lead to a forced outage on the feeder.

In summary, this case has demonstrated the potential to detect subtle changes in the operation of distribution feeder equipment. This provides another example of the potential to anticipate future faults and take preemptive steps to alleviate them before they cause problems noticeable to customers.

Transmission Line Fault

Case Summary

Up to this point, all of the case studies presented have focussed on events in which a fault or incipient fault on a distribution feeder caused anomalous behavior of one or more monitored parameters. This final case is different in that the underlying fault originated on the transmission system that supplies the substation from which the monitored feeder originates.

One of the pre-prototype data collection systems recorded a series of significant two-phase voltage dips over a period of seven minutes. The nature of the data suggested that it was likely that the cause of the voltage dips originated on the transmission side of the delta-wye substation transformer. Texas A&M researchers notified the host utility of this and provided available data and their assessment of those data.

The utility investigated and found that at the time of the voltage dips, equipment of an unspecified nature had contacted the transmission line that serves the substation. The host utility in this case purchases power from a third party. The transmission line on which the fault occurred is owned by the third party, which did not make more detailed information about the fault available to the host utility.

Recorded Data

On September 14, 2001, one of the pre-prototype data collection systems recorded a series of five events over a period of approximately seven minutes. The series of five figures beginning with Figure 5-58 illustrate the three-phase RMS substation voltages from these events. Figure

5-63 illustrates the three-phase RMS substation currents corresponding to the fifth instance of the event.

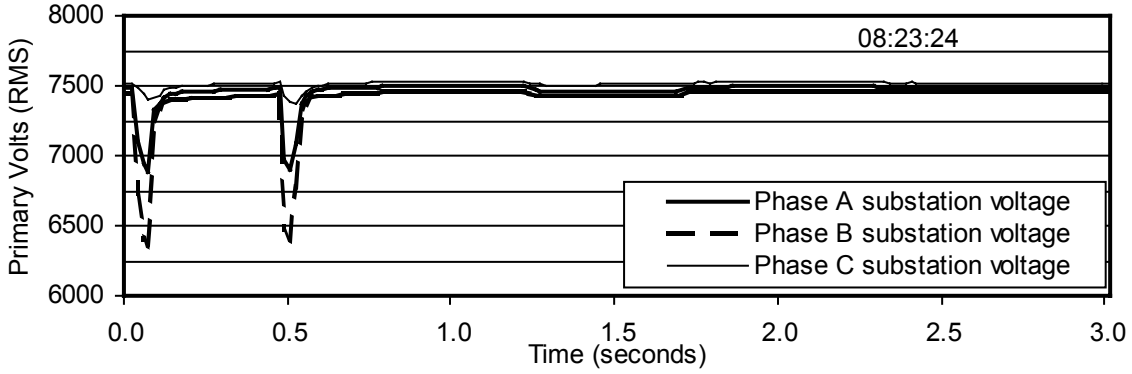


Figure 5-58
First Instance of Voltage-dip Event

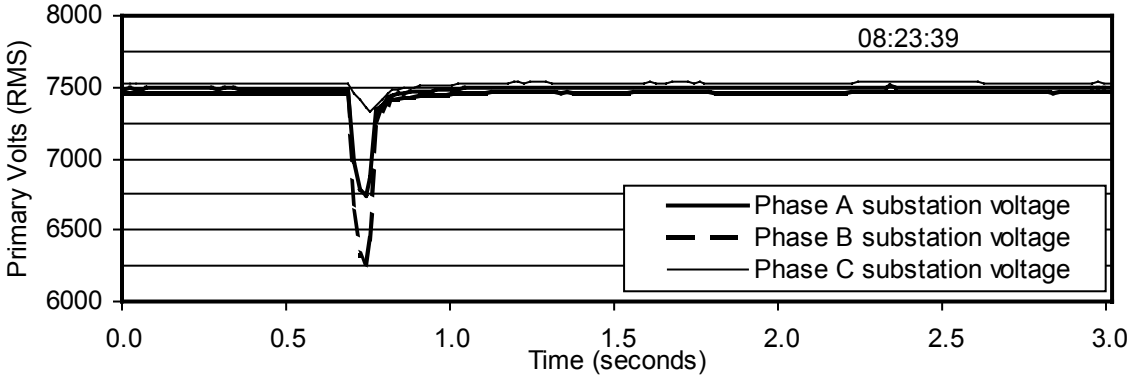


Figure 5-59
Second Instance of Voltage-dip Event

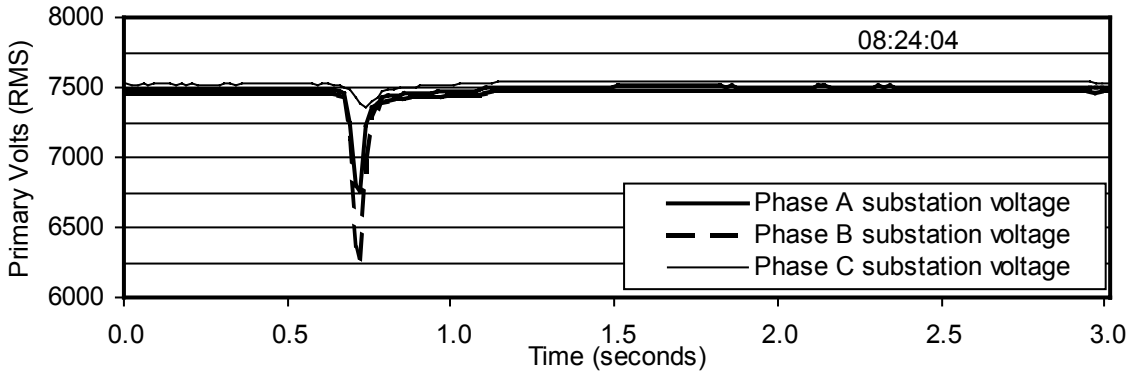


Figure 5-60
Third Instance of Voltage-dip Event

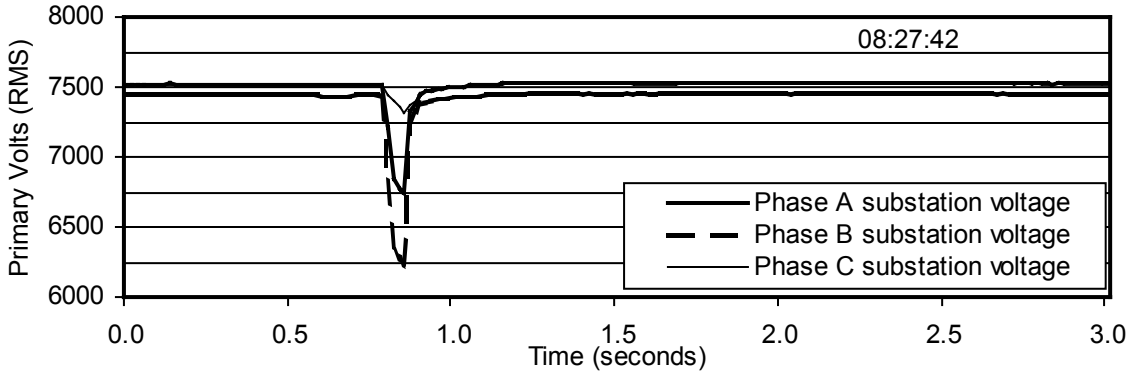


Figure 5-61
Fourth Instance of Voltage-dip Event

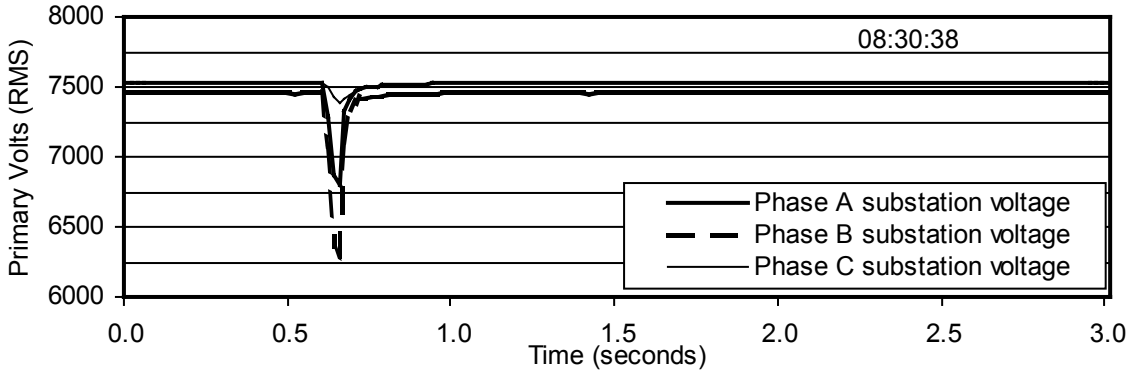


Figure 5-62
Fifth Instance of Voltage-dip Event

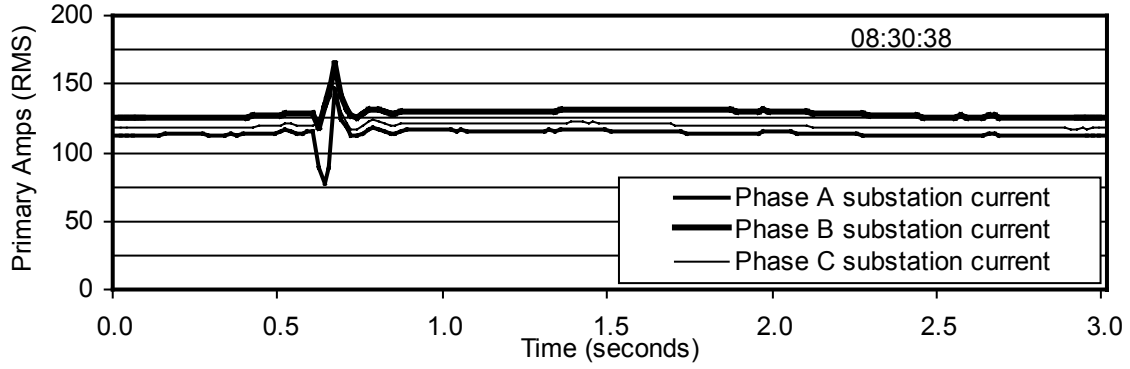


Figure 5-63
Substation Currents Corresponding to Figure 5-62

Analysis of Recorded Data and Utility Involvement

The research team noted that two of the phase voltages dipped significantly during each of the five recorded events. One of the voltages dipped by an average of 14.8 percent with a 0.6-percent standard deviation. The other dipped by an average of 9.8 percent with a 0.9-percent standard deviation. The similarity between all five events strongly suggested that they had the same underlying cause.

The most obvious explanation for the observed voltage waveforms would be a phase-to-phase fault. However, the phase currents during these events did not change significantly (see Figure 5-63), certainly not enough to cause the observed voltage dips.

Another possible explanation would be a phase-to-phase fault on an adjacent feeder emanating from the same substation bus. This certainly would cause two of the phase voltages to dip at the bus. However, this particular substation does not have any adjacent feeders so this could not have been the cause in this particular case. Further, while phase-to-phase faults certainly do occur on distribution feeders, they are far less common than single-line-to-ground faults. Therefore, even if this substation did have one or more adjacent feeders, the fact that two-phase faults are not all that common suggests that it would be wise to examine other possible explanations if any exist.

In this case, there were at least two other possible explanations. The substation transformer that serves this feeder is connected in a delta configuration on its transmission side and in a grounded-wye configuration on its distribution side. Therefore, a line-to-ground fault on the transmission side of the transformer will cause dips in two of the phase voltages on the distribution side of the transformer. This is exactly what the pre-prototype measured in each of these events.

Another possible explanation that the researchers considered was a fault on a distribution feeder emanating from another substation served by the same transmission system. They discounted the likelihood of this explanation, however, for two reasons. First, in order to cause the measured two-phase voltage dip, a fault on a feeder at a remote substation would have to be a phase-to-phase fault. As mentioned above, these faults happen on distribution feeders but they are far less common than single-phase faults. Second, the voltage dips were fairly significant in magnitude, measuring as much as 14.8 percent below nominal. It is unlikely that a fault on a remote distribution feeder would cause this much of a voltage dip on the transmission system, which would have been necessary for it to cause such a dip on the local substation bus.

The research team analyzed these events within hours after the pre-prototype recorded them. After considering all of the possible explanations listed above in light of the recorded data, they determined that the most likely cause of this type of voltage dip on the distribution system was a line-to-ground fault on the transmission system. They provided this information to the host utility, along with their assessment of the likely cause.

The host utility already was aware of a problem that had occurred on the transmission system. The host utility does not own the transmission line that serves this particular substation so they

contacted the line's owner for details. They learned that an unspecified piece of equipment had come into inadvertent contact with the transmission line. This resulted in an overcurrent fault, which in turn caused the phase voltages on the distribution system to dip.

The host utility was unable to obtain many details about this fault but did learn that overcurrent protection operated to isolate the fault. Examination of Figure 5-58 and the two figures that follow it suggests that the overcurrent protection for the transmission line actually tripped and reclosed several times before locking out. The first recorded event (Figure 5-58) actually shows two dips, separated by approximately one-half of one second. The times of occurrence of the events in the second and third figures are within a time span of less than a minute after the first event. Analyzed more closely, the events' time stamps strongly suggest that the line's overcurrent protection locked out after four trips, after attempting to reclose at 0.5, 15 and 40 seconds after the initial overcurrent.

The last two occurrences of the event are more difficult to explain because they happened several minutes after the initial event. Any attempt at an explanation would be purely speculative, but perhaps these represent an operator making two attempts to close the breaker manually, with automatic reclosing blocked.

Case Discussion

This case study differs from all the others presented in this report in that the underlying cause of the measured parametric changes originated on the transmission system that serves the monitored feeder. Events such as this are not specifically the target of this research effort, but this case is included because it demonstrates the need to be able to classify a wide variety of events that affect distribution feeders, even those that do not originate on the monitored feeders themselves.

Many normal system events cause changes in various monitored parameters on distribution feeders. In addition, parametric changes may be the result of events that truly are faults but that are on other feeders or even on the transmission system. It is important to consider and study these events for at least two reasons. First, certain types of events (such as the one described in this case study) can have negative effects on the monitored feeder. In some situations, knowing about these events could alert the utility company to the problem and allow them to make repairs.

Second, to be of practical use, any implementation of this technology likely would require automatic classification of many events and, perhaps, automatic determination that particular events are not of interest. Some of the types of events that may occur on the transmission system or on adjacent feeders may not be of interest but they may cause parametric changes similar to those that occur during events that are of interest. Therefore, a practical system would need to be able to discriminate between them.

In summary, the pre-prototype installations have enabled researchers to gather information about events on adjacent feeders or on the transmission system as well as events on the monitored feeders themselves. This case study illustrates one such example. These records will be quite valuable when designing algorithms for practical use.

6
CONCLUSIONS AND FUTURE PLANS

Summary

Competition is relatively new to the electric utility industry and it requires electric utility companies to rethink the way they do business. They must maintain high-quality service in order to attract and retain customers. At the same time, they must operate efficiently if they are to be able to offer competitive rates and still operate profitably. These two requirements are at odds with one another.

Most traditional feeder maintenance is preventive in nature and includes activities such as infrared scanning, tree trimming, and other time-based inspection and maintenance activities. By setting conservative (i.e., frequent) cycles for these maintenance activities, utilities can locate and repair some incipient fault conditions before they escalate in severity and force interruptions or outages. Unfortunately, this approach is very expensive and inefficient, because much of the time and effort is spent testing and maintaining perfectly healthy components. However, cutting back on maintenance capriciously has deleterious effects on the ability of the system to delivery reliable, high-quality power.

At the outset of this project, Texas A&M University researchers designed and performed experiments in which they simulated incipient fault conditions. This experimental work demonstrated that such conditions produce electrical evidence of their existence. This evidence can be present for long periods of time before the utility company or its customers know that any problem exists.

Based upon this foundational experimental work, the research team designed a pre-prototype data collection system. They constructed and installed four such systems at four different utilities across the continental United States and monitored them remotely for over a year. They recorded early warning signals associated with several types of incipient faults, including:

- Lightning arrestor failure
- Capacitor-bank switch chatter
- Encroachment of trees in overhead primary
- Incorrect jumper-wire installation

Future Plans

The work undertaken to date shows exciting possibilities. The ability to detect early warning signs of incipient faults and provide utility companies with advance notice of problems has the potential to address both of the competing requirements of better service and lower operating costs. Texas A&M, EPRI, and EPRI's member utility companies recognize this potential and seek to capitalize on it.

Near-term Plans

At the time of this writing, EPRI is planning a second phase to this project, which will take two to three years to complete. The goals of the next phase will be to develop a more formal approach for anticipating faults. To do that, the effort will include building a broader database of incipient events, more fully involving the utility participants and automating much of the data collection and analysis process. This Phase II effort is in the planning stages, so the particulars are subject to change. However, in general, it is anticipated that the tasks of Phase II will be as described in the following subsections.

Expanded base of utility companies, substations and feeders

In Phase I, the pre-prototype data collection systems collected valuable information that showed the potential for anticipating faults. However, the number of such installations was relatively small. Only a limited number of incipient faults occurred during the period of a year on such a small number of circuits. Further, a small number of feeders necessarily represents only a limited set of operating environments (e.g., heavily treed exposure versus coastal exposure versus exposure to nearby petrochemical processing plants versus…). Finally, although not as obvious, each utility has its own operating practices and procedures. Each of these factors may influence the characteristics that certain types of incipient faults display. In addition, different utilities' systems may display different patterns during normal operation as well.

One of the goals of Phase II will be to expand the number of monitored feeders significantly. This factor alone will allow considerable expansion of the database of recorded incipient events. Equally importantly, Phase II also will increase the number of utility companies, thereby giving exposure to a wider variety of operating practices. Finally, having a larger number of utility companies will result in exposure to wider geographic and environmental conditions. Taken together, these factors should result in not only a greater number of events in the database but also a greater variety. The availability of a wider variety and greater number of events should result in the development of more robust fault anticipation techniques.

Prototype Hardware and Software

The pre-prototype data collection system used in Phase I was suitable and appropriate for the proof-of-concept phase. Each system monitored one feeder. The total number of monitored feeders was four, one at each of four utility companies. Because the total number of systems,

substations and feeders was relatively small, it was feasible to perform much of the data collection process manually.

In Phase II, there will be a significantly larger number of utilities, substations, and feeders. Therefore, a more appropriate hardware and software platform will be needed. The first task of Phase II will involve the design of a prototype system that will accomplish several enhancements over the pre-prototype data collection system. Although the project still is in the planning stages, it is anticipated that these enhancements will include the following:

- More feeders per prototype – Whereas the pre-prototype hardware and software were capable of monitoring one feeder per device, the prototype design anticipated for Phase II will be modular and will allow configurations of between one and eight monitored feeders per prototype. This will vastly decrease the cost for substations where the utility company desires to monitor multiple feeders, because the incremental cost of adding a module to monitor an additional feeder will be only a fraction of the cost of an entire pre-prototype system. Further, it is anticipated that the production cost of even a one-feeder prototype will be considerably less than the cost of an equivalent pre-prototype.
- Automated data collection – During Phase I, personnel manually initiated the retrieval of statistical data and high-speed event captures on a periodic basis. This was time- and labor-intensive but it was acceptable for four feeders. However, the larger number of feeders and locations anticipated during Phase II will make automation of this process essential. Accordingly, it is anticipated that part of the Phase II effort will concentrate on the design of a master station that will retrieve all appropriate data automatically on a regular cycle.
- Data management – In addition to manual data collection, Phase I also involved manual data management. Again, this was time- and labor-intensive but acceptable given the relatively small number of sites. The volume of data collected under Phase II will increase proportionally with the significantly greater number of feeders, making automation of data management crucial. Therefore, the design of the master station for Phase II will place significant emphasis on formalizing and automating the management as well as the collection of data.

Greater Utility Involvement and Education

During Phase I, Texas A&M researchers sought and received valuable help from the host utilities whenever they needed to determine the underlying power system cause of anomalous data measurements. However, the research team performed all of the data collection, management, and analysis internally. This was appropriate for this initial proof-of-concept phase. In Phase II, the host utilities will have a far greater portion of the responsibility.

This approach will benefit the overall project in at least two ways. First, by giving the utilities significantly more responsibility, the participants will learn more of the details of the technology: how to interpret data, what the technology can and cannot do, etc. Second, it will provide more opportunity for the ultimate users of the technology to affect practical issues regarding implementation and operation.

Expanded Database of Incipient Events

Phase I successfully recorded multiple events that demonstrated the concept of using on-line monitoring to detect incipient faults, thereby improving service quality, reducing interruptions, etc. These events spanned a wide variety of incipient conditions, from lightning arrestor deterioration to tree encroachment. The number and variety of detected events were good, especially considering the small number of feeders monitored and the limited amount of monitoring time. However, because of this limited exposure, the existing library of events currently contains only a small sampling of each type of condition, in many cases only one. Further, it is certain that there are numerous other categories of incipient fault conditions that the pre-prototypes did not encounter.

The significantly larger number of utility companies, substations and feeders anticipated for Phase II should expand the database of recorded events dramatically. The increased number of substations and feeders should increase the number of events. The increased number of participating utilities will greatly increase the prototypes' exposure to different operating environments, utility practices, etc.

Finally, the utility companies that participate in Phase II will commit significantly more manpower to the project and will be much more directly involved in the day-to-day operation and use of the technology. This should result in more of the recorded anomalies being "solved." In other words, the utility engineers who are responsible for this project will have more time to devote to diagnosing and documenting the events that the prototypes record. This type of effort, feedback and documentation will greatly enhance not only the size of the database of events but, more importantly, increase its usefulness.

Automated Recognition of Recorded Events

Phase I demonstrated the concept of detecting anomalies on distribution feeders. However, researchers performed the process of diagnosing these anomalies manually. For proof-of-concept and research purposes, this was appropriate but in widespread day-to-day operations, the manpower requirements would be too great to be of practical use.

Therefore, significant research effort during Phase II will concentrate on automating the diagnostic process. It is anticipated that the greatly expanded database of well-documented events will provide the basis for this effort.

Long-term Vision

Phase I has shown exciting potential and it is anticipated that Phase II will reveal additional capabilities and automate much of the data management and analysis process. In the long term (i.e., three to four years), this fault anticipation technology promises great practical benefit for utility companies. It would be impossible at this point to imagine or enumerate all possible benefits, but it is appropriate to speculate about several potential areas of investigation.

Underground Distribution System Failure Anticipation

Until this project confirmed that failing equipment on the mostly overhead distribution system generates incipient pre-fault signals, few thought it possible to "anticipate" faults before they occurred, that is, before they caused high currents to flow. An area of additional investigation should be undertaken to determine if underground power distribution systems exhibit similar behavior. Questions such as "Do pre-fault signals exist?" and "Are they detectable?" cannot be answered reliably until underground distribution systems (networks and radial feeders) have been monitored and studied in a manner similar to that used for assessing overhead system.

Better Tree Trimming Management

Phase I of this project discovered an electrical parameter that correlates with line clearance (i.e., tree trimming) activity on overhead lines. With additional work, it may be possible to turn that parameter into an indicator of the need for tree trimming and to prioritize the order in which feeders are trimmed. This would allow utilities to extend their trim cycles and target only those areas where clearance work really is needed. Considering the many millions of dollars that a utility spends annually for line clearance, any reduction or even deferral of expenditures translates into substantial savings.

Conclusion

This project has demonstrated a truly exciting potential. The ability to detect a wide range of incipient fault conditions on electric distribution feeders before they cause problems for utility companies or their customers has widespread ramifications. Anticipating equipment failures would allow utility companies to make preemptive repairs and avoid faults and outages. Correlating changes in electrical parameters with the level of contact between trees and overhead lines would enable utilities to defer periodic tree trimming until it is actually necessary, without negatively affecting power quality or service reliability. These are but two of the most obvious benefits of this technology.

Work completed to date has proven the presence of measurable parametric changes that accompany conditions such as failing electrical components, intrusion of trees, etc. These changes provide the basis for anticipating faults, thereby improving service and reducing wasted costs. It is anticipated that the next phase of the work will broaden the database of observed and measured events, automate the process of analyzing the data and provide the basis for bringing practical fault anticipation closer to reality.

7
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Target:
Distribution Systems

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Printed on recycled paper in the United States of America

1001879

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