ELECTRIC POWER
RESEARCH INSTITUTE

Distribution Fault Anticipation

Phase III: System Integration and Library Enhancement

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PRODUCT DESCRIPTION

Distribution fault anticipation (DFA) technology demonstrates groundbreaking advances in the detection and recognition of subtle electrical precursors of line-apparatus failures. Failure and incipient-failure signatures have been documented with the advanced instrumentation of 60 feeders across North America. Pilot demonstrations are evaluating and advancing the technology, using a custom commercial beta platform. Methods are being demonstrated to transform large amounts of fault and incipient fault data into useful information without human intervention.

Assistance in technology licensing and technology transfer is available to manufacturers who want to add the technology to their product lines. The technology continues to advance through pilot demonstrations and a consortium established for utilities and manufacturers.

Results and Findings
This report provides information about multiple issues regarding implementation and integration of DFA technology for practical use and an update on recently documented failure signatures. It also provides information about other projects complementary to the Electric Power Research Institute- (EPRI-) funded effort.

Applications, Value, and Use
DFA technology impacts a wide spectrum of utility engineering and operating personnel. It detects precursors to failures (for example, in-line switch failures). It also recognizes improper operation of line equipment (for example, excessive switching of capacitor banks). This provides tools to achieve greater awareness regarding system health, enabling preemptive action to avoid outages.

Ubiquitous digital devices can provide data to supply the underpinnings for better awareness and, therefore, operation of power systems. However, the sensitive monitoring required for detecting subtle failure precursors produces too much data to be analyzed with manpower-intensive processes. This project has put significant focus on the automation of data capture, retrieval, analysis, management, and presentation processes.

EPRI Perspective
DFA technology represents the state of the art in intelligent monitoring of distribution feeders. Many capabilities have been demonstrated, and work is under way to enable utilities to realize benefits in day-to-day operations. Significant potential remains to be tapped, and the technology continues to expand. EPRI is making a Project Opportunity available for additional utilities to participate in pilot demonstration projects.

Keywords
Distribution
Failure prediction
Reliability
Signature analysis

ABSTRACT

Reliability and operational economics drive today's electric utility company. Both are critical, yet they are at odds with one another. Traditional maintenance programs can help achieve and maintain high levels of reliability, but these programs are very expensive. EPRI-funded research at Texas A&M University has investigated the detection and characterization of electrical signals to determine when faults and incipient faults are developing on distribution feeders, and to use this information to target maintenance resources where most needed.

Early efforts demonstrated the proof of this concept and collected data from operating feeders by capturing, documenting, and characterizing signatures indicative of failures and incipient failures. This entailed the instrumentation of 60 feeders at 14 substations of 11 utility companies across North America, and resulted in the collection of a massive amount of operational feeder data and numerous signatures associated with various stages of apparatus failure. Researchers developed algorithms to characterize collected data and demonstrated the ability to use this data to diagnose many faults and fault precursors.

Early research used methods conducive to the discovery and fundamental characterization of failures and events on the power system, particularly those previously unstudied or undocumented. Some facets of the research instrumentation and methodologies are not practical for widespread deployment and day-to-day use by utility companies. The current project has examined system concepts and architectures that enable the technology to be transitioned from research project to practical application, to be fully scalable to the largest utility systems.

Prototype data collection equipment continues to build the already extensive failure signature database. This adds signatures related to multiple, previously undocumented failures, providing the basis for recognizing additional failure modes in the future. This database will serve researchers for decades to come.

EPRI has licensed DFA technology for commercial development. There is significant synergistic benefit to having the conceptual system integration work proceed in parallel with the licensee's implementation of commercial beta hardware and systems, with the two projects feeding and complementing each other. Other complementary projects are underway to explore distributed application of DFA technology and to assess non conventional sensors that may provide sensing alternatives with lower installed cost, to make widespread deployment of DFA and other advanced monitoring functions more feasible. The licensee also makes sublicenses, know-how, and technology transfer services available to third-party manufacturers.

ACKNOWLEDGEMENTS

This project has enjoyed the active participation and support of numerous utility companies. These companies have committed time and resources to acquire and install equipment, allocate significant levels of personnel effort, and provide other support and guidance along the way. This support has been key to the success of the project. EPRI and Texas A&M University gratefully acknowledge these companies and their contributions. Participating utility companies are:

- BC Hydro
- Consolidated Edison
- CPS Energy
- Exelon
- Keyspan Energy/National Grid
- MidAmerican Energy
- Northeast Utilities
- Southern Company/Alabama Power
- Tennessee Valley Authority/Pickwick Electric Cooperative
- Oncor Electric Delivery

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INTRODUCTION AND BACKGROUND

Rationale and Justification

Deregulation, retail competition, and other factors have forced electric utility companies to change their mindset and practices. The historical position of a utility as a regulated geographic monopoly offered steady, predictable rates of return to utility companies and their investors. As long as utilities could provide an acceptable level of service by doing things they always had done, there was little incentive to seek innovative avenues of reducing operating costs or pushing reliability to a higher level. These business and technical environments no longer exist.

Today, utilities must offer affordable service if they are to attract and retain customers. At the same time, there are ever-increasing pressures to provide more reliable service. Traditional means to achieve high reliability include significant expenditures in the area of preventative maintenance of system components. By their nature, preventative maintenance programs are expensive, spending considerable sums of money and resources maintaining line equipment, in full recognition that much of that equipment is perfectly healthy and would continue to operate well for a long period of time. However, the alternative is to defer maintenance, testing, etc, which reduces reliability because of the failure of those few components that are operating in a degraded condition and nearing catastrophic failure.

Utilities have always had to make tradeoff decisions between costly maintenance and acceptable reliability levels. The advent of rigorous and affordable digital technology offers alternatives that did not exist 20 years ago. Protective relaying is arguably the best example of system functionality to take advantage of microcomputer technology, with digital relays now being the protection technology of choice for most new installations and many retrofit applications. In addition to mimicking the function of their electromechanical predecessors, these digital devices provide additional functions and value, as well as performing self diagnostics, which has reduced the need for periodic maintenance of the devices themselves.

The process of digitizing and processing electrical quantities has gained acceptance for substation devices and applications, and to a lesser extent for distributed devices. Besides relays, other digital devices have made significant inroads into monitoring and control functions for substations and feeders. In the late 1990's, EPRI contracted with Texas A&M University to investigate the feasibility of using digital data collection and analysis to detect electrical changes that were believed to accompany deterioration of line apparatus, to alert utility personnel to developing problems before they or their customers knew a problem was developing. This concept became known as fault anticipation, because it would allow utilities to anticipate problems that were developing and thereby avoid failures and outages by taking preemptive action – with less reliance on inefficient, time-based, preventative maintenance programs.

Evolution of DFA Premise

The Distribution Fault Anticipation (DFA) project began with the following initial, fundamental premise:

> ***Equipment often degrades slowly over time. As it does, it produces measurable electrical changes. Recognizing these changes provides the basis for "anticipating" faults, thereby avoiding full-blown failures, faults and outages.***

Project efforts proved this premise correct, by documenting numerous electrical signals associated with multiple types of failures and failure precursors. As often happens in the course of conducting research, however, it became apparent that the data acquisition, analysis, and management processes underlying the anticipatory functions also made additional capabilities feasible, leading to a broader premise:

> ***Analysis of electrical signals can be used to improve reliability, operations, and situational awareness, by detecting early signs of equipment degradation and improper apparatus function.***

For example, when a permanent fault locks out a sectionalizing mid-point feeder recloser, it is not strictly "anticipatory" to provide dispatch personnel with timely notification of the outage and characteristics that can improve response and restoration time (e.g., phase, magnitude, observed protective device response characteristics, amount of load lost). However, providing such information, in a highly automated way, can positively impact reliability. As a more specific example, if a mid-point feeder recloser locks out and causes an outage to half of that feeder's customers, most dispatchers today do not know anything is wrong until customers begin calling. Even then, they typically do not know the extent of the outage until numerous customers call. Automated methods for acquiring data, analyzing it, and providing summarized information to dispatchers can help them respond better, in some cases even before outage calls are received.

Algorithms and methods developed during the DFA project can recognize momentary and permanent faults, and provide significant information about them without human intervention. This includes faults that cause feeder breaker operations, but it also includes faults that cause momentary or permanent operation of downstream sectionalizing devices, such as fuses and reclosers. This project has demonstrated the ability to provide this level of information, in a highly automated way, using only analog waveforms acquired from substation-based current and potential transformers (bus PTs and feeder CTs). Stated another way, this is done without communications with sectionalizing devices and without digital status inputs.

Algorithms and methods developed can detect and characterize electrical waveforms from normal and abnormal phenomena on feeders. For example, transients produced by capacitor banks switching on or motors starting are acquired and analyzed. Electrical precursors to failures of in-line switches and splices also are acquired and analyzed. The acquisition, analysis, and characterization of these varied signals are performed with automated processes that do not require human intervention.

Sensitivity versus Data Volume and Manageability

Project results indicate many incipient failures produce measurable electrical changes, but that these changes are subtle and often of the same order of magnitude as normal system events. For example, incipient failure of a service transformer winding may produce momentary current variations of 20 amperes or so, but a large motor may cause current variations of similar or greater magnitude. Figure 1-1 illustrates this, by placing current measurements of these two signatures side-by-side. Both waveforms are from substation-based feeder CTs, and therefore contain around 180 peak amperes of steady-state load current. In the figure, momentary increases can be seen in excess of the steady-state load. These are caused by the events of interest: incipient winding failure on the left; motor start on the right. The two current changes have similar magnitudes. At a more detailed level, Figure 1-2 shows that the two signatures have characteristics that are unique from one another. Detailed analysis of the two signatures can distinguish the failing winding from the motor startup, but this distinction cannot be made on magnitudes alone. In more general terms, incipient failures often produce electrical changes with magnitudes similar to those produced by normal system events. Therefore a diagnostic system that captures data sensitively enough to capture incipient failures also will capture normal system events. Because incipient failures are substantially less frequent than normal systems events, only a small fraction of the data captured will be caused by incipient failures.

Bus voltage is not significantly affected by either event. Therefore, monitoring systems that capture data based on voltage perturbations would not capture these events.

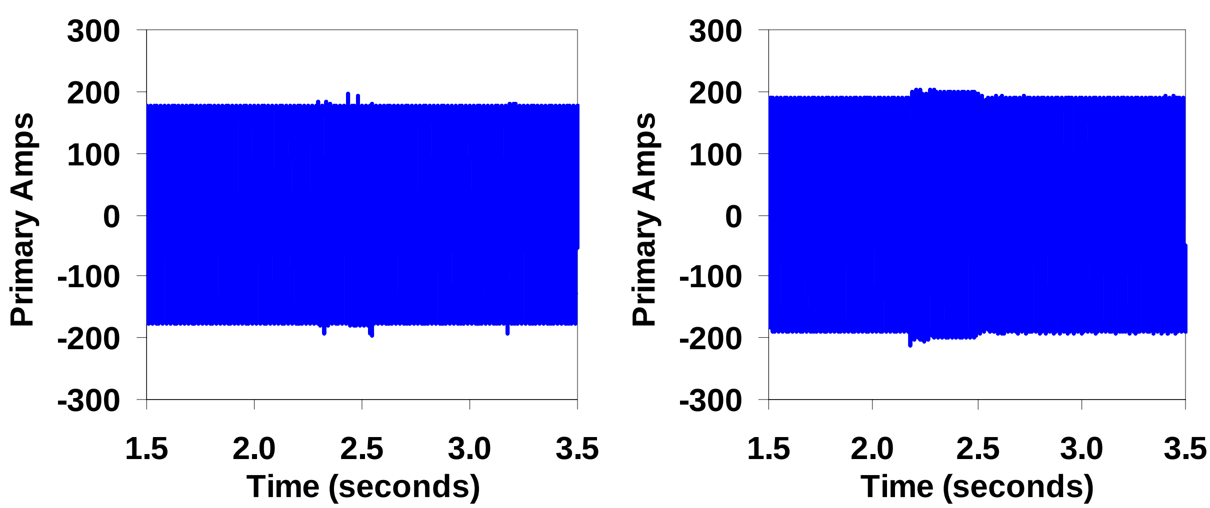
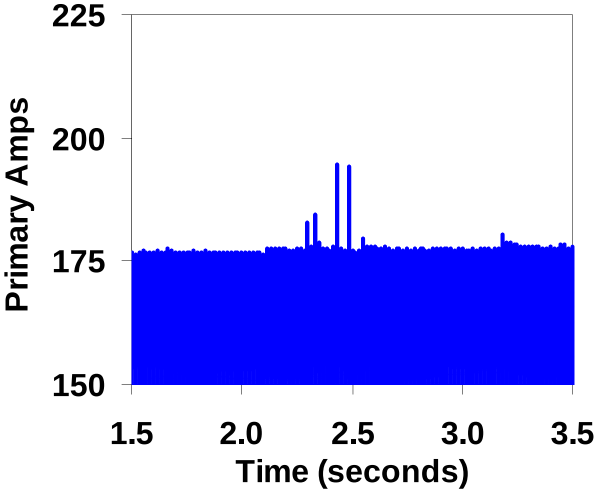


Figure 1-1
Current Changes of Incipient Transformer Failure (left) and Normal Motor Start (right)



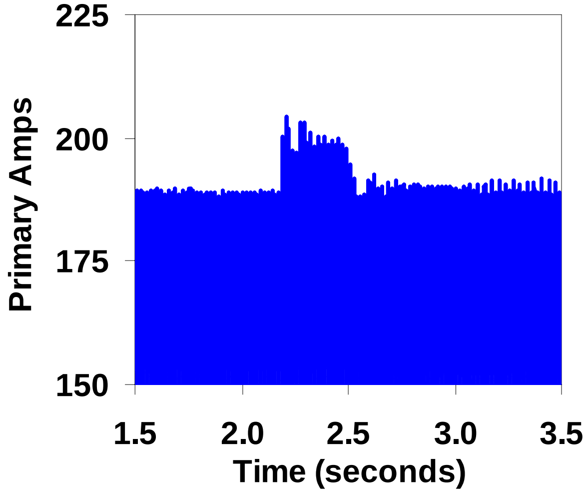


Figure 1-2
Detailed View of Signatures of Figure 1-1

Users of electronic waveform recorders, such as digital fault recorders (DFRs) and power-quality (PQ) meters have always found it necessary to make tradeoffs between sensitivity and data manageability. Highly sensitive triggering results in excessive data, all of which requires retrieval, analysis, archiving, and potentially action. By contrast, less-sensitive triggering produces a more manageable volume of data, but it ignores subtle perturbations, such as the incipient transformer winding failure discussed above. DFRs generally are used to study protection response to high-current faults, and accordingly are configured to record waveforms only upon the occurrence of high currents. PQ meters typically are used to study voltage-related phenomena that affect a utility and its customers, and are therefore configured to record when significant voltage perturbations occur, often where voltage deviates from nominal by five to ten percent or more. Users of these and other devices recognize that triggering more sensitively could capture more subtle events of interest, but that doing so would increase the volume of data collected. Increased data recording implies an increase in the amount of data that must be retrieved, analyzed, archived, summarized, and otherwise processed and managed. When "data overload" occurs, all data loses value, because no one has the time to sort through it to identify the waveforms of true interest.

The preceding discussion is intended to give the reader an appreciation of the need for and implications of sensitive monitoring. It is instructive to quantify the order of magnitude of the data volume necessary. Project results have indicated that an average feeder may experience 10 events that trigger data recording each day, during normal operation. Most of these recordings represent normal system operations, such as motor starts, capacitor switching, and line switching. When incipient-failure conditions develop, the signatures they produce often are erratic and aperiodic, and may occur dozens to even hundreds of times in a single day. However, a figure of 10 events per day per feeder is sufficient to discuss rough scale. If one considers a medium-sized power system of, say, 500 feeders, this equates to 10 events/day/feeder x 500 feeders = 5,000 events/day for that system. No utility has sufficient human resources to manually analyze any sizable fraction of these events on a regular basis, much less all of them.

These and other issues regarding data volume and the need for highly automated processes to minimize required manpower have been considered throughout the project. The remainder of this chapter provides details about the history of the various phases of the project. The next chapter (Chapter 2, *System Integration Considerations*) then elaborates on specific topics necessary for practical implementation of DFA technology in day-to-day utility operations.

Phase I: Proof of Concept

Texas A&M began its first formal EPRI-funded project in the area of fault anticipation in 1997. The goal of that project was to determine the validity of the initial, fundamental premise set forth above. The scope of that project involved the design, construction, and installation of equipment to perform sensitive substation-based monitoring of three feeders, one at each of three host utility companies.

Data collection was accomplished with continuous monitoring, to detect subtle changes in a variety of electrical parameters and record high-fidelity data when such changes occurred. Researchers periodically polled substation-based data collection equipment, via dial-up modem, to retrieve newly captured data. A member of the research team then examined each recorded event waveform to determine the likely cause on the power system, and queried utility personnel to investigate where appropriate.

The Phase I proof-of-concept project provided encouraging results. Over a period of approximately two years, the project documented several examples of line apparatus exhibiting detectable changes in electrical parameters, before the utility company or its customers experienced problems. A primary limitation of this phase of the research was that its scope was limited to three feeders. A further limitation was that the process of retrieving and processing data was manpower-intensive.

The data collection protocol was to install the monitoring equipment and then wait until failures developed. There were no artificially created or accelerated incipient failures. Utility maintenance on the monitored feeders continued according to normal utility protocols and procedures. Therefore the number of incidents of incipient failures on three feeders over a nominal two-year period was limited. The incidents that were discovered, however, encouraged EPRI and its members to expand the scope in a Phase II project.

Phase II: Field Data Collection and Algorithm Development

Texas A&M undertook the second phase of the DFA project in the year 2000. This effort expanded the number of monitored feeders significantly, increased the number of utility companies involved in data collection, and increased the level of interaction between the research team and utility engineers.

Texas A&M designed a prototype data collection system with capabilities that were enhanced in comparison to the systems used in Phase I. This system made it feasible for utility companies to purchase these prototype systems and instrument more feeders. Approximately eleven utility companies installed prototype monitoring systems in fourteen substations across North America.

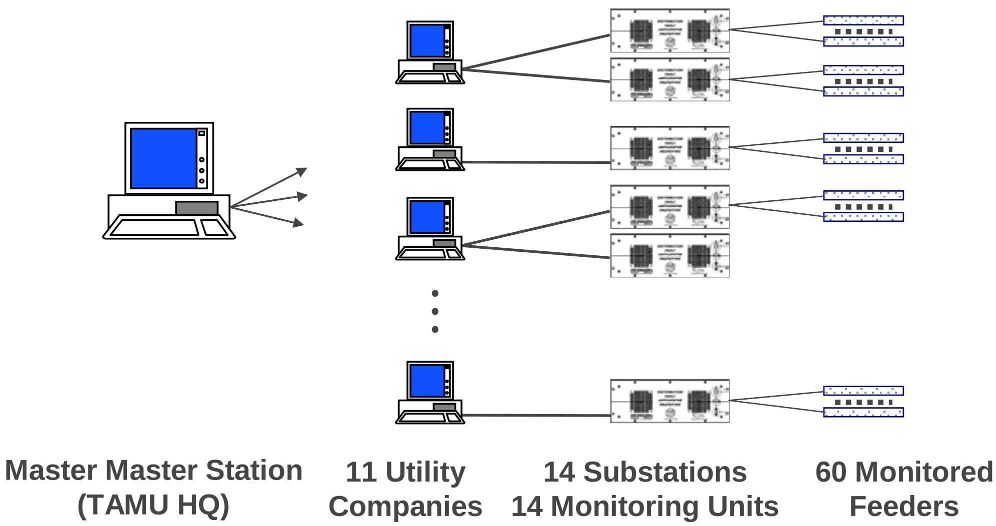


Figure 1-3
Network of Distribution Fault Anticipation (DFA) Prototypes

Each prototype was designed and configured to monitor between two and eight feeders, depending on the desires of the participating utility company and the configuration of the selected substation. In total, sixty feeders were instrumented and monitored, as illustrated in Figure 1-3.

Data retrieval and analysis procedures were performed manually in Phase I. The research team recognized that these manpower-intensive procedures would not be feasible for the expanded number of sites and feeders to be monitored in Phase II. Therefore the master station for the prototype system was designed to automate many of these processes in this second phase.

The system took advantage of the growing availability of high-speed Internet for data retrieval. It automated data retrieval to utility-owned master stations, and to a "Master Master" station at Texas A&M. This made data collection more efficient and reduced manpower requirements.

Participating utilities were more directly involved during the second phase. After installing prototype equipment, they were responsible for investigating interruptions, outages, and other abnormal occurrences. They also were responsible for determining which recorded data was associated with these events. The utility companies needed direct access to the data to do this. Master station software therefore allowed each utility direct access to collected waveforms and means to attach classification codes and other information related to those waveforms.

The expanded effort resulted in a large volume of data and the characterization of numerous normal and abnormal feeder events. As previously noted, configuring data collection devices always involves a tradeoff between data sensitivity and data overload. The tradeoff analysis and decisions were particularly important and difficult at the beginning of the DFA data collection effort. There was no prior body of work to guide researchers regarding the types or levels of signals they might encounter. There was little knowledge about apparatus failure modes and even less knowledge about how progressive failures manifest themselves electrically over time. Because incipient faults do not occur with great frequency, it is important to be configured sensitively enough to capture these infrequent events when they do occur.

As a result of these sensitivity considerations and tradeoff analysis, and in light of the fact that early weeks and months of the project held much uncertainty about characteristics of signals to be discovered, the data-collection equipment was designed with considerable flexibility in its ability to be configured, and initial, default settings were quite sensitive. The systems allowed remote reconfiguration to adjust sensitivity when a particular unit clearly was capturing more or less data than appropriate. A bias was maintained toward high sensitivity, to avoid missing important events, although that meant that numerous, normal-system events would be captured and would have to be retrieved, analyzed, archived, etc.

As expected, this data-collection philosophy captured many events, the vast majority of which were normal system operations, such as capacitors switching and large motors starting. Project personnel developed considerable knowledge about the signals that occur as various apparatus begin to deteriorate. They became adept at analyzing captured waveforms and using these waveforms to recognize underlying, causal, power-system events. Utility engineers provided much-needed feedback to determine details about failures that occurred. As the project progressed and personnel became better able to diagnose failures and incipient failures from captured data, feedback from utility engineers continued to validate those diagnoses.

The expanded data-collection effort of Phase II documented numerous failures and failure precursors. The Phase III project continued to take advantage of the installed network of prototype systems. Data from these systems continues to document additional types of failure modes and enhance the robustness of their characterization.

The various phases of the project successfully identified and documented a wide variety of failures, incipient failures, and operational problems with apparatus, including one or more episodes of each of the following.

- Voltage regulator failure
- LTC controller failure
- Lightning arrestor failure
- Recurrent overcurrent faults
- Line switch/cutout failure
- In-line splice failure
- Cable failures
  - Main substation cable failure
  - Primary URD cable failure
  - Secondary overhead cable failure
  - Secondary URD cable failure
- Tree/vegetation contacts
  - Contacts with primary
  - Contacts with secondary services
- Overhead transformer bushing failure
- Overheard transformer winding failure
- URD padmount transformer failure
- Substation bus capacitor bushing failure
- Capacitor problems
  - Controller failures (excess operations)
  - Failed capacitors
  - Blown fuses
  - Switch restrike
  - Switch sticking
  - Switch burn-ups
  - Switch bounce
  - VAR tolerance problems
  - Pack failure

Some types of failures were quite common and numerous episodes were documented. As may be obvious from the list above, capacitor failures were prevalent. Some types of failures are statistically less probable and less frequent than others. Therefore, the project documented large numbers of certain types of failures but relatively few episodes of other types of failures. For some, only one example occurred and was documented during the project.

Researchers developed methods for characterizing many of the captured events. Those failure modes with the greatest representation in the database provided the best opportunity to develop, test, and refine characterization methods, with events that occur less frequently providing more limited opportunity for characterization. Methods continue to be evaluated and refined as time passes and new episodes occur.

Conclusions from Phase II Project

The large-scale data collection activity of Phase II project demonstrated the ability to detect, characterize, and many types of normal and abnormal behavior on distribution feeders. The field devices served primarily as data-capture devices. Master station computers at each host utility company and at Texas A&M headquarters retrieved captured event data from these field units for analysis and processing. Researchers developed algorithms for characterizing captured events. They created processes for running these algorithms on captured data automatically as they occurred and were captured. Over time, the continued processing of new events allowed researchers to evaluate the efficacy of various algorithms and to refine them where appropriate.

To facilitate a reasonable mechanism for developing, testing, and refining algorithms for processing data coming from the 60 feeders, algorithms initially were implemented in MatLab™ and were run on a computer server system at Texas A&M headquarters. This required all recorded data to be retrieved to Texas A&M's server, via Internet connections to the substations. The volume of data was immense, but manageable for a research project with 60 feeders. It would not be feasible to retrieve, store, archive, etc. this level of data on an ongoing basis, for the hundreds or thousands of feeders a typically utility would monitor with fully deployed DFA technology. In addition, this processing hierarchy requires high-speed data transfer (e.g., cable modem, DSL, and the like) to transfer all data back to a centralized location for processing. Industry trends are beginning to result in more substations having high-speed Internet service, but such presence is far from universal and will remain so for many years to come. In addition, if DFA technology were to be applied at poletop locations outside the substation, it would not be reasonable to assume that high-speed Internet would be available to most of those locations.

This phase purposely relied on centralized data retrieval, processing, and archiving, to facilitate learning for the first time what kind of electrical signals incipient failures produce, and to facilitate development and testing of methods for characterizing these signals and signatures. Some of the processes (e.g., archiving) were not fully automated and would be unreasonably cumbersome in full deployment. Communications, storage, and processing realities and limitations dictate that a significantly different architecture is needed to make DFA technology practical. Considerable work was needed, to develop appropriate architectures and determine requirements for system integration. That work has been the focus of the Phase III project. In addition, while Phase II greatly expanded the knowledge base about apparatus failures, it did not result in the acquisition of the entire universe of failure modes and mechanisms, particularly for events that may be statistically infrequent, but that may have very significant ramifications when they do occur. The existence of the system of data-collection systems put in place during Phase II made it natural to continue learning from these in-place systems to further develop and refine characterization algorithms. Therefore, Phase III focused both on development of concepts related to system integration and on continued data collection and algorithm development and refinement.

2
SYSTEM INTEGRATION CONSIDERATIONS

Distribution Fault Anticipation (DFA) research has always had as its goal the development of practical concepts to improve utility operations and reliability. Early phases of the research validated the premise that sensitively monitoring electrical signals could provide means for recognizing degradation and imminent failures.

Practical implementation of DFA technology is made possible in large part by sweeping advances in microelectronics. DFA technology is arguably the most advanced continuous, real-time system ever contemplated for widespread deployment on distribution systems. The level of data acquisition, storage, processing, and the like would have been impossible or at least cost-prohibitive even a decade ago. Even with today's advances, careful attention must be devoted to practicing DFA functionality properly, without creating requirements that would make it manpower-intensive or cost-prohibitive.

Phase III has been directed toward defining means to perform basic DFA functions, in ways that are practical for widespread implementation, deployment, and practice by utility companies. Important considerations conceptually fall into several broad categories, which are discussed in the sections below. It will become clear that there is considerable overlap between categories.

Data Fidelity

Distribution Fault Anticipation (DFA) technology acquires and analyzes waveform data representing line currents and voltages. Other substation devices acquire and analyze similar data quantities. The most obvious example is the digital relay, which senses current and perhaps voltage waveforms, analyzes these waveforms in real-time, and makes control decisions about when to trip a feeder breaker or take other control action.

Basic quantities used by the DFA are similar to those sensed by other substation- or feeder-based devices. However, the purpose for which these quantities are sensed is vastly different, and therefore, the requirements for the fidelity, rate, duration, etc. also are very different. Relaying applications, for example, generally need to represent and recognize large current levels, typically in the range of hundreds or thousands of primary amperes. Protection coordination and other considerations require relays to have reasonable accuracy and resolution, but there is little need to discriminate relatively minor differences in current. For example, a feeder relaying application set with a 600-amp pickup value would be indifferent to feeder current that changes from 300 amps to 310 amps for a cycle or so. Such variations happen routinely as a result of normal system activity, such as a motor starting. Neither of these readings would indicate a need to trip the feeder. Even above the pickup level, there is little substantive difference between, say, 900 and 910 amps from the perspective of system protection or the time the relay takes to make a trip decision.

By contrast, DFA functions work on subtle changes in current and voltage levels. The ten-ampere change in the example above might be an early indication of an incipient fault condition (failing apparatus, tree contact, etc.). However, a failure precursor and a small motor both might produce momentary ten-ampere increases. Differences in temporal and spectral behavior before, during, and after the momentary increase may be the differentiating factor between a normal event that should be "ignored" and a precursor to a fault that should be further analyzed and reported. The DFA relies on the data acquisition system to faithfully reproduce voltage and current waveforms with sufficient resolution to sense these minor variations and reproduce their shape, magnitude, and frequency content appropriately for the application.

Some digital substation- and feeder-based devices are influenced negatively by transient signals and frequency components other than the fundamental frequency. Devices and applications for these purposes may go to great lengths to exclude transients and other non fundamental frequency components. By contrast, applications like the DFA rely on the analysis of transients and other non fundamental frequency components to function properly.

Digital devices routinely state the number of bits of resolution of their analog-to-digital (A/D) converters. This is an important specification, but can be misleading unless additional factors about the fidelity of the analog conditioning and other circuitry are known. For example, if a device had a full-range reading of 20,000 amperes and incorporated a 14-bit A/D converter, this would imply that it could discriminate signal differences of $20{,}000/2^{14} = 1.22$ amperes. However, the related electronics may introduce electromagnetic noise into the signal path, which the A/D converter sees added to the real signal at its input. Some signal-conditioning electronics introduce noise equivalent to several bits of the A/D converter's range, reducing its <u>effective</u> resolution. For example, if circuitry introduces white noise equivalent to the three least-significant bits of the A/D converter's output, then the effective number of bits of resolution is reduced from 14 to 11, and the effective resolution becomes $20{,}000/2^{11} = 9.77$ amperes. Signal differences less than the effective resolution are buried in electronic noise and are not reliable for analysis. The cited resolution likely would be adequate for traditional applications, such as relaying, but insufficient for sensitive applications like the DFA. Parenthetically, it should be Digital noise-removal techniques exist that can effectively recover bits lost to white noise, but these work only on periodic, steady-state signals. They are not effective during transients or when signals are dynamically changing from one cycle to the next. Dynamic temporal response is necessary for incipient-failure diagnosis, making these noise-removal techniques unsuitable for DFA applications.

Sample rate is another key consideration for practicing DFA technology. As with most such considerations, there are tradeoffs involved. Each data sample must be acquired, moved, managed, and processed by the processor, and these data handling and analysis requirements are roughly proportional to sample rate. Applications like conventional overcurrent relays are interested in fundamental frequency current and do not require fast sample rates. Early digital relays used slow rates, such as four samples per cycle. They could perform their protective function with this limited sample rate. Over time, sample rates have increased significantly, largely because it was recognized that sampled currents and voltages could be stored and used for other purposes. However, many protective relays still have insufficient sample rates for full practice of DFA technology, because of the relatively broadband signals that the DFA uses.

Data Storage and Management

Proper practice of DFA technology requires the acquisition, manipulation, management, and storage of a large volume of data. As in the previous section, it is useful to contrast DFA data requirements with those of traditional digital devices, such as relays. Modern relays and other digital devices have provisions for storing acquired data waveforms, so that engineers can later evaluate fault-current levels and determine whether protection systems operated correctly. Relays typically store several cycles of data per event and have the capability of storing multiple such events before exhausting available memory. Total storage may be on the order of multiple seconds when all event records are considered together.

Some of the types of events that DFA technology analyzes and characterizes happen over considerably longer periods of times than conventional faults. In addition, the types of events captured and processed by the DFA may only give intermittent signs of their presence. For example, a tree limb contacting a primary conductor may make physical contact only intermittently. During these contacts, there may be sufficient electrical activity to be detected, but when the limb mechanically separates from the line (e.g., because of varying wind conditions) there is no detectable signal. The DFA may see multiple episodes over a period of hours, days, or weeks. Proper diagnosis of the problem therefore may require analysis of multiple, distinct episodes spread over a significant period of time.

Data collection equipment used during early phases of the project used commercial-grade components and had hard disk drives for long-term data storage. This likely is not practical for ruggedized equipment that is meant for long-term substation or distributed installation. Other forms of data storage generally have better reliability, temperature performance, etc, but more limited capacity. Therefore, issues related to data retention, archiving, etc, become more important considerations for full deployment and application.

In addition to having large amounts of storage for retaining captured data on the data collection field units, captured events and other data of interest were moved to Texas A&M's server. Archiving of the data was done from this server. Therefore, the data collection units in the field could retain data for a relatively long period of time (e.g., many months) before nearing capacity, and they could simply delete their oldest data when they neared their storage limits. Data storage and management functions require more careful thought and planning when less space is available and when the bulk of the collected data is not being sent to a server for archival purposes. As previously noted, most events that the DFA captures are normal system events, like capacitors or large loads switching. Keeping high-fidelity records of these events generally is less important than keeping records related to incipient faults or other system problems. A simplistic "FIFO" (first-in-first-out) approach of simply deleting events and other data, based solely on time, results in important, "old" events being discarded, while "new" episodes of routine system events are retained. Clearly this is not an optimal solution.

Processing Architecture

DFA prototypes relied on characterization to be performed at a server at Texas A&M. This was appropriate and desirable for research purposes. It allowed the use of user-friendly software and development tools. It also allowed refinements and modifications to be implemented without the burden of distributing new software to multiple field devices whenever changes were made. However, this required that all data be retrieved to Texas A&M's master station, and that the master station perform all of the processing.

The time between an event's occurrence on the power system and when it has been characterized was limited primarily by the ability to get captured event data to the server. Time is not critical for responding to many developing incipient conditions, and delays of a few hours have no real consequence. For other types of events, however, time delays can be more critical. For example, consider a case that one of the DFA prototypes captured, in which a forked tree limb broke and hung over a single-phase overhead line. It pulled the line down and caused intermittent contact with the neutral wire mounted several feet below the phase conductor. This caused an overcurrent fault, which was cleared temporarily by a momentary poletop recloser operation. The fault/trip/reclose sequence recurred about an hour later, when the limb again made contact. Nothing further happened over the next 16 hours, but then, the fault/trip/reclose sequence occurred 14 more times over the next few hours, finally resulting in the line burning down. This caused a downed-conductor situation and a one-hour outage for 140 customers. The utility believes it could have used DFA-provide information (i.e., faulted phase, fault magnitude, observed recloser characteristics, etc.) to locate this problem with a few hours of notification, and therefore could have prevented the ultimate damage and outage, but only with timely notification. Each event that the DFA captures creates a waveform file that is several megabytes in size. The speed at which these files are transported from the substation back to a central processing location depends on the communications medium available to the substation. This determines the speed at which assessments can be made and results delivered, which affects the utility's ultimate ability to respond and prevent escalation, faults, and outages.

Scalability is also a significant concern when considering an application that is as data- and processing-intensive as the DFA. The master station server at Texas A&M handles data from the 60 instrumented feeders well, but it is clear that it could not handle the data and processing burdens for a utility with DFA technology deployed on several thousand feeders.

An obvious part of the solution is to move as much of the data handling and processing burdens to the lowest possible level in the system hierarchy. This is the approach taken with the revised platform that is being used for pilot demonstrations.

Processing Burden

Another concern for a digital device responsible for real-time or near-real-time processing is processing burden. The processor must be able to meet the average processing burden, such as continually acquiring samples, computing derived quantities such as RMS, checking quantities against thresholds, etc. These functions must proceed without interruptions in the data stream or significant latency. In addition to continuous, baseline processing, the processing system must be able to analyze and characterize aperiodic anomalies, without exceeding acceptable delays between the time an anomaly occurs on the power system and the time at which information is brought to the attention of appropriate users. The acceptable delay differs depending on the type of event and the utility's planned response to that type of event. To use a previously cited example, if a tree limb is hanging on a line and causing intermittent faults that eventually may burn the line down, delays of a few minutes likely are acceptable, but delays of multiple hours are not. Conversely, if a capacitor is switching ON and OFF too frequently, a delay of hours or even a few days likely would be acceptable.

During the research phases, the processing architecture was such that all functions related to data acquisition, threshold comparisons, triggering, and data capture occurred on the field devices, but analysis and characterization functions were done on a centralized server. For full deployment, this is not a desirable architecture, for a variety of reasons. If a utility were to broadly deploy DFA technology on thousands of feeders, the processing burden soon would overwhelm a centralized system. Multiple centralized servers could be used, but this still would not be an optimal solution because of the other issues, such as transporting the voluminous data to the central location, requiring high-speed communications to all locations, etc.

If all processing is not to be done at a centralized location, the most obvious location for it to occur is within the data collection device itself. Prototype systems had limited processing capabilities, and characterization algorithms were optimized for ease of implementation and evaluation, not for optimal processing. However, issues related to distributed processing were considered in the Phase-III project, and the platform implemented as part of the concurrent, DOE-funded project (see *Pilot Demonstrations*, page 4-2) distributes the processing burden.

Communications

Prototype systems used for research required high-speed Internet to field data-collection devices. Making this a requirement going forward would limit the locations where DFA technology could be deployed. Ramifications of applying the technology in distributed, pole-mount locations are considerable as well, in that communications to these distributed locations generally will be more limited than to substation-based devices. Therefore one key to the deployment of DFA technology is to minimize its reliance on communications, particularly high-speed communications. This again dictates toward performing more of the processing on the field devices and transporting less information back to a centralized location.

Connection to Electrical Signals

In the prototype hardware, a "feeder module" card provided standard terminal strip connections for connecting to a three-phase feeder via the secondary connections of five-amp current transformers and 120-volt potential transformers (CTs and PTs). The prototype system consisted of one chassis in each monitored substation, and this chassis could accommodate up to eight feeder modules, as well as providing peripheral connections such as keyboard, mouse, monitor, and Ethernet connections for connecting to the outside Internet and for allowing a user to connect via laptop. This basic requirement for connecting to conventional CTs and PTs continues in the current platform being used for pilot demonstrations.

Prototype devices housed multiple feeder monitors in a single chassis, which required the utility to bring CT and PT leads from all monitored feeders to a central location in the substation. The degree of difficulty to accomplish this was determined by the configuration of the substation and other factors. Some utilities had little difficulty accommodating the wiring for this, but others had considerable difficulty, with those utilities with eight-feeder units generally having more difficulty than those with fewer feeders to monitor.

Some participants expressed their opinion that requiring centralized CT and PT connections might be burdensome for widespread deployment, perhaps prohibitively so. Therefore, it is desirable to be able to distribute sensing and data acquisition around the substation, so that CT and PT wiring runs can be reduced. However doing this creates other technical challenges. For example, it is relatively straightforward to synchronize the sampled data of multiple feeders when all of the feeder modules physically reside in a common chassis. This becomes more difficult when modules are distributed at multiple locations in the substation. While most DFA functionality does not strictly require absolute sample synchronization between the multiple feeder modules, it is desirable to maintain reasonable time synchronization between the modules to best classify data captures that result when an event on one feeder causes sympathetic data captures on other feeders. The DFA Feeder Monitor device currently being used for pilot demonstrations overcomes the centralized-wiring requirement, by housing each Feeder Monitor in a separate chassis. However, connection to conventional CTs and PTs is still required. The current platform provides separate sample-synchronization connections, which can be used to connect all Feeder Monitors within a substation in a daisy-chain fashion. The sample-synchronization connections can be accomplished with signal-grade cabling and do not require the high-power CT and PT secondary leads to be run to a central location in the substation.

Sample synchronization and multi-feeder diagnoses require signaling and communication between the multiple feeder module locations. There are multiple types of candidate media to accomplish this, but each has its limitations and costs. Conventional media such as copper wiring may be acceptable between physically proximate devices, but unacceptable between dispersed devices, because of concerns about ground potential rise within the substation. Wireless communications have been suggested to overcome this and to achieve a low-cost solution. Wireless communications have certain limitations as compared to conventional communications, such as latency, bandwidth, and reliability. Wireless systems also raise concerns about data security vulnerabilities, so some utilities are unwilling to allow wireless communications in substations. Also the effects of electromagnetic interference on wireless systems are not well understood, particularly at the times when communications are most needed, such as during major system faults and other events. Fiber communications offer immunity from electromagnetic interference and from ground potential rise, but the expense of acquiring and installing the fiber optic cables is higher than with the other media.

Integration with Existing Platforms

Preceding sections have noted that other digital systems exist in substations today. The most common of these are digital relays, and to a lesser extent, power quality monitors, digital fault records, and other devices. These existing platforms perform some of the same fundamental functions that are required for DFA technology. Each connects to sensors (e.g., CTs and PTs, or other sensors), conditions and digitizes electrical waveforms, and performs some type of processing on these waveforms. Virtually all modern platforms can store waveforms when anomalies occur, and make these waveforms available to utility personnel for analysis.

Integrating multiple functions in a single device could produce benefits, compared to having multiple, single-function devices. There would be potential for savings in terms of the devices themselves. There also would be potential for savings in panel space and CT/PT wiring costs.

As previously outlined, the DFA captures and processes subtle changes in electrical parameters, which traditional systems ignore. This places higher requirements on the system than many other functions may require, in the various areas outlined in preceding paragraphs. Manufacturers wishing to incorporate DFA technology into their product lines will have to determine what, if any, modifications are needed to their existing designs to provide the foundation for practicing DFA technology in parallel with their existing functions. The challenges and possibilities of such integration are discussed in more detail in Chapter 6, *Areas for Further Research.*

Sensing

DFA prototypes receive inputs from conventional current and potential transformers (CTs and PTs). For many applications this is the most logical means of acquiring current and voltage signals from the power system. In many traditional substation installations, it is straightforward to tap into existing CT and PT secondary circuits to obtain inputs for the DFA.

A logical extension of DFA technology is distributed application at multiple points along feeders. This has the potential to provide more sensitive monitoring and more accurate location of failures and incipient failures. At distributed points, there often will be no existing CTs and PTs, so sensing will have to be added. The cost of installing a full complement of CTs and PTs can be considerable and may be a limiting factor in the widespread application of DFA technology in distributed applications. Even where conventional CTs and PTs exist, connecting to them can be difficult or prohibitive in some circumstances. This can be true both for distributed applications and for substation installations.

Multiple alternative means exist for sensing currents and voltages. Some are commercially available and others are in various stages of development or field testing. The cost of some of these sensors may be lower than the cost of new CTs and PTs, particularly when installation costs are included. Therefore, it is natural to consider alternative sensors as inputs to the DFA. However, variations in the transfer characteristics of sensing devices will affect the end application. This is true in general, and particularly in the case of a technology like DFA, which looks for subtle parametric changes.

The ramifications of differences in input signal characteristics are unknown. Many alternative sensor types may have been qualified for specific purposes. For example, a particular sensor may have been qualified according to conventional standards of accuracy, making it acceptable for sensing RMS current or voltage levels for SCADA application. That sensor may not have been tested or qualified for sensing harmonics, however. Other sensors may have unknown performance with respect to transients, saturation, or a number of other factors. Phase shifts may be introduced at different frequencies, changing the overall shape of the resulting waveforms. Any of these factors may affect performance of DFA functionality in unknown ways.

It might be possible to modify DFA functions if a particular sensor's performance were well understood, even if that performance differed from the performance of conventional CTs and PTs. However at the current time, there are many unknowns. Going forward it will be important to better understand the performance of various alternative sensing means, particularly to the types of subtle, time-varying signals the DFA uses.

Chapter 4 discusses a complementary project that is attempting to answer some of the questions concerning comparative characterization of certain non conventional sensors, and their potential for fulfilling the sensing needs of DFA and other advanced technologies.

3
DATA COLLECTION AND CASE STUDIES

The Phase II project resulted in approximately 60 feeders being instrumented in 14 substations at 11 EPRI-member host utility companies. This created a substantial infrastructure of data collection equipment, most of which continues to operate and collect data.

In addition to developing system integration concepts in the Phase III project, researchers also continued to collect data from this existing network of data collection systems. The project team also continued supporting utility engineers in the interpretation of anomalies that occur on their systems.

DFA prototypes have recorded numerous episodes of faults, incipient faults, and operational problems with power system apparatus. Some types of events have significant representation in the existing database. Others are represented by only a few, or even a singular episode. The ever-expanding database allows researchers to assess characterization algorithms and make adjustments where suboptimal performance is observed. For those types of events that have been captured previously, but for which there are relatively few episodes in the existing database, new episodes allow researchers to improve the robustness of the characterization algorithms.

The following case studies document a variety of failures and failure precursors. Unless otherwise noted, utilities involved in these cases had no monitoring equipment or other information to tell them underlying failures were developing, or to help them assess problems after they occurred, other than the DFA.

Feeder Monitoring Strategy and Topology

Figure 3-1 describes the generalized monitoring topology used in the project. Except where otherwise noted, this applies to all of the case studies that follow. The basic monitoring device is the DFA Feeder Monitor. A self-imposed project constraint was that no active signal injection or other exotic sensing means be used. Rather, each Feeder Monitor connected to three, five-amp current transformers (CTs) and three, 120-volt potential transformers (PTs). Because most substations have only one complement of bus PTs, rather than individual feeder PTs, the bus PTs were connected to each Feeder Monitor's PT inputs. Each substation had between two and eight feeders instrumented, one Feeder Monitor per feeder.

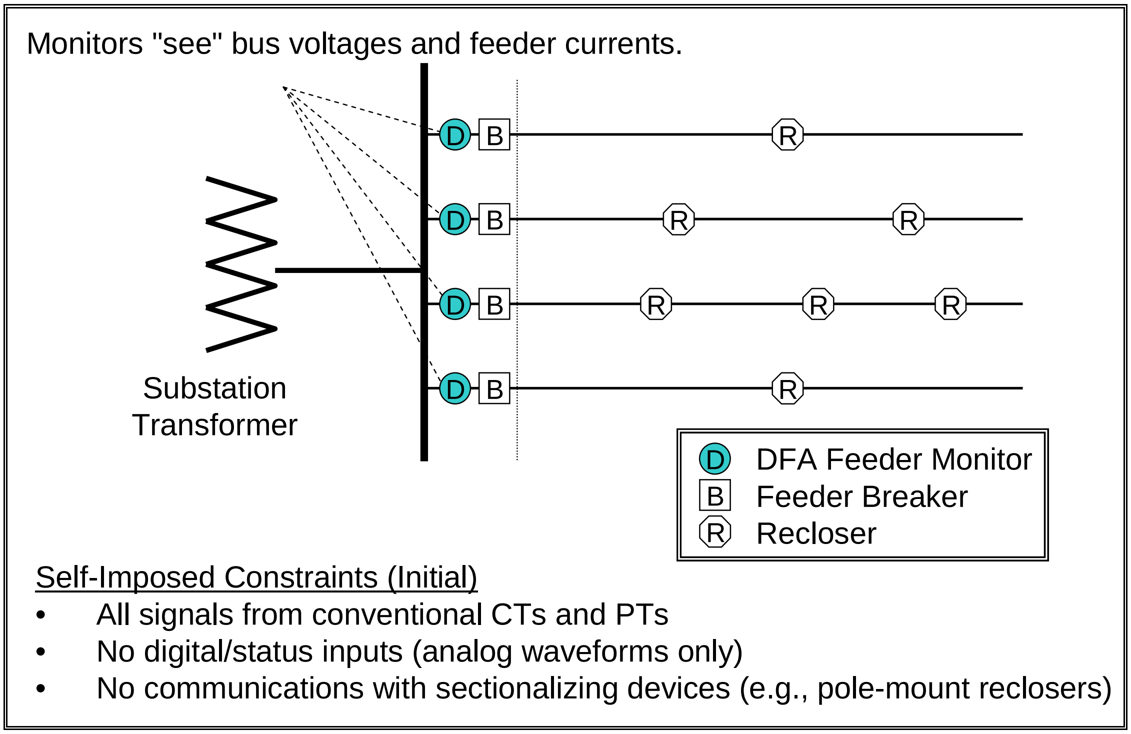


Figure 3-1
One-Line Diagram of Typical Substation-Based Feeder Monitoring

Case Study #1: Avoided Outage from Failing External Transformer Bushing

Figure 2-3 shows currents produced by an overcurrent fault that a DFA prototype registered December 11, 2005 07:39:58. The fault produced approximately 2,400 RMS amps of fault current. A single-phase, poletop recloser (i.e., not the feeder breaker) tripped after two cycles and then reclosed two seconds later, at which point the fault did not persist. There was nothing particularly remarkable about this event. There were no outages or customer complaints, and the utility company was unaware that anything had happened, except from the DFA.

Another fault occurred two days later, December 13, 2005 08:21:05. It was on the same phase and produced approximately the same current level as the first fault. A single-phase recloser again operated after two cycles, and reclosed two seconds later. As before, there were no outages or customer complaints, and the utility had no indication of the fault, except from the DFA.

Alerted to the two nearly identical faults by the DFA, utility personnel searched for the cause the next day. A two-man crew used information from the DFA and found the problem in less than one hour. They found a poletop service transformer (see Figure 3-3) with a damaged bushing. They also found a dead squirrel at the base of the pole. The conclusion was that the animal caused the first short circuit (December 11, 2005). The poletop recloser cleared the fault properly. The animal’s body fell away and did not result in a permanent fault. However, the short-circuit arc across the transformer bushing caused permanent damage to the bushing. This compromised the bushing's insulating ability and resulted in the later fault.

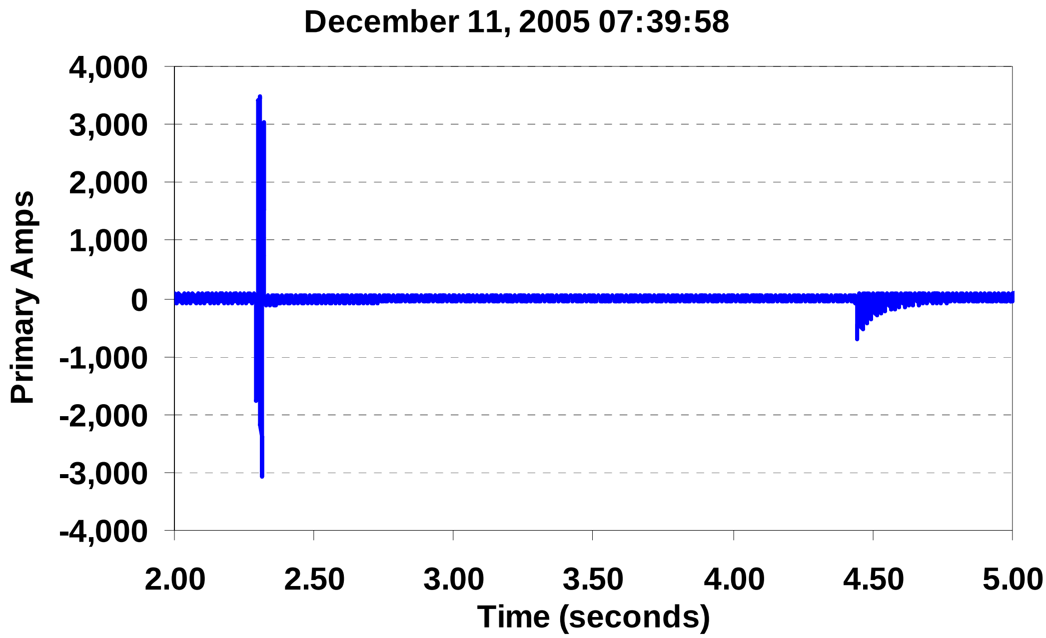


Figure 3-2
Routine Single-Phase Fault Cleared by Poletop Recloser

Figure 3-3
Transformer with Damaged External Bushing That Caused Intermittent Faults

After identifying the problem, the utility put replacement of the transformer on its work list. Before the repair was made, however, the fault recurred on December 18, 2005, prompting the utility to expedite the repair. The fault did not recur after the replacement was made.

The third episode was instructive from a research perspective. It provided further evidence that the damaged insulator would continue causing intermittent faults. Left uncorrected, repetitive short circuits and arcs are known to escalate and create larger problems. For example, repetitive high-current events likely would cause arc damage to the transformer housing, potentially resulting in a breach that would allow moisture to enter the transformer and mix with its oil. This has potentially catastrophic consequences, including an explosion inside the transformer that can cause a “lid launch” and eject burning oil and ignite proximate items and structures.

These faults occurred on a feeder with multiple reclosers distributed along its length. The utility used information from the DFA to narrow the search to a small area, allowing them to find the failure efficiently. This is significant, because the normal process of finding an intermittent fault can be tedious and time-consuming. An investigation often begins with a customer complaint of “blinking” or “flickering” lights. Customers generally are not able to differentiate between voltage sags and momentary interruptions. Therefore the utility has no guiding information about whether a problem really exists on the distribution system, what kind of problem it might be, or where it is located. It is not uncommon for the process of finding an intermittent fault to require multiple days or even weeks, during which the utility company makes multiple patrols, checks recloser operations counters, and the like. By contrast, in the subject case, the utility knew of the problem without customer complaints, and made one trip to find the problem with less than one hour of effort.

In summary the utility benefited from the DFA in several ways:

- Notification that a problem was developing – Absent the DFA, the utility had no other indication that a problem existed. No other device indicated any problem and there were no customer complaints.
- Locating the problem – Locating a fault can be difficult. It becomes even more difficult when it is an intermittent fault that has not caused a sustained outage, particularly if the feeder is long and geographically dispersed. This utility has seen all of these factors come into play with recurrent faults. By contrast, the utility was able to use the DFA to locate the subject problem with a two-man crew in less than one hour.
- Zero customer complaints – This incipient failure was detected and repaired without any events that caused any customer complaints at any time.
- Avoidance of sustained outage – This recurrent fault caused three momentary interruptions in a one-week period, but it did not cause a sustained outage. As will be described in the next case study, recurrent faults do not tend to go away by themselves. They can be quiescent for significant periods of time, but eventually they recur. Given enough time they escalate and cause sustained outages. In the present case, the utility avoided a sustained outage.

Case Study #2: Outage Following Recurrent Faults

The single-phase fault of Figure 3-4 occurred on the morning of June 3, 2006. A recloser carrying most of the feeder load tripped and reclosed, and there was no sustained outage. Multiple similar faults occurred over the next several weeks, each causing the recloser to trip and reclose without causing a sustained outage:

- 6/3/2006 08:02:46 – First episode of subject fault (Figure 3-4)
- 6/10/2006 07:27:38 – Second episode of subject fault
- 6/17/2006 10:16:34 – Third episode of subject fault (Figure 3-5)
- 6/24/2006 08:29:46 – Fourth episode of subject fault
- *6/28/2006 07:32:45 – Unrelated single-phase fault (Figure 3-6)*
- 7/4/2006 06:07:12 – Fifth episode of subject fault
- 7/24/2006 07:29:25 – Sixth episode of subject fault (Figure 3-7), resulting in outage

All of the faults during this period were similar, except the one on June 28, 2006 (Figure 3-6). It too was a single-phase fault involving phase A, but there were significant differences in the amount of fault current and the fault's duration. This fault also tripped a different recloser.

The sixth episode (Figure 3-7) occurred on July 24, 2006, and caused the recloser to operate to lockout. This resulted in a sustained outage for 907 customers. When the utility investigated, they found a situation similar to the one in the previous case study. It is believed that an animal on a transformer caused the initial fault on June 3, 2006, and that this event caused latent damage to the transformer. The five other fault episodes, including the one resulting in a sustained outage on July 24, 2006, occurred as a direct result of this damage.

This utility has experienced multiple past cases of recurrent faults on DFA-monitored feeders, and has used DFA information to locate and solve the underlying problems before they caused sustained outages. The present series of faults occurred over a seven-week period, so why did the utility not recognize and fix the problem before an outage occurred?

The answer becomes clear when one examines the time between episodes. The first four were at precise one-week intervals, occurring on June 3, 10, 17, and 24. There was a momentary interruption each time, but the interruptions happened just once per week, and there were no customer complaints or other indications of trouble. The engineer with access to the utility's DFA prototype examined DFA records regularly. His practice was to periodically examine the previous seven-day period for problems, including recurrent faults. This was reasonable, because previous cases typically had shown periods of minutes to hours to perhaps a few days between episodes, and he successfully avoided multiple outages using this practice. In this case, however, the faults were just far enough apart that no two showed up together in a seven-day history.

This case makes an important point about practical widespread application of DFA technology. Sensitive monitoring results in a large number of events being captured. Chapter 2 discusses the volume of data that sensitive systems record for each feeder, in search of early indications of subtle problems. Application on hundreds or thousands of feeders across a large utility's system will produce an overwhelming volume of raw data. The present case study is a good illustration of the need to automatically extract and organize the relatively few "actionable items" needed by utility personnel. Otherwise the volume of routine data and the passage of time conspire to bury morsels of truly useful information.

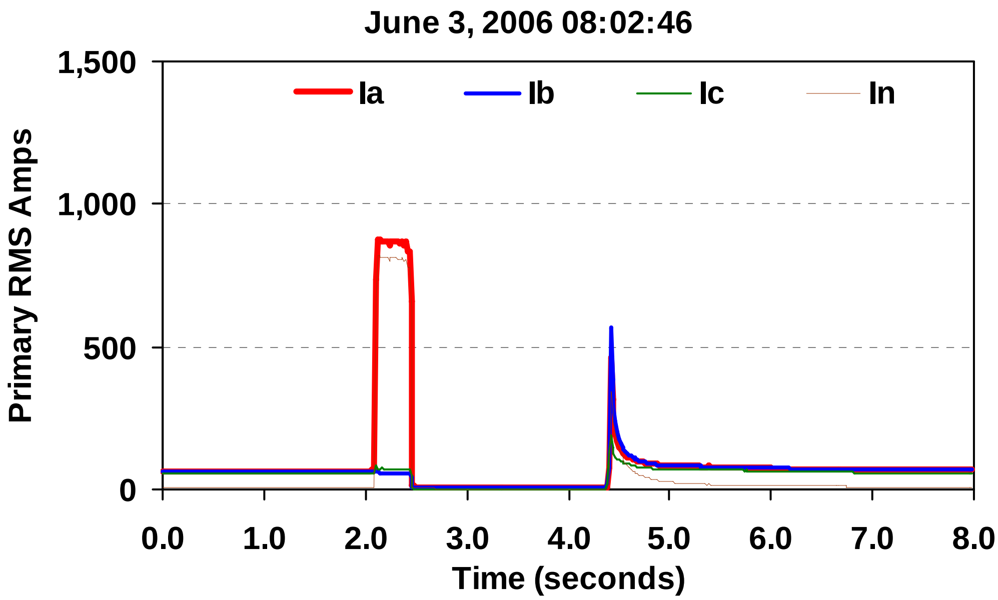


Figure 3-4
First Episode of Recurrent Fault

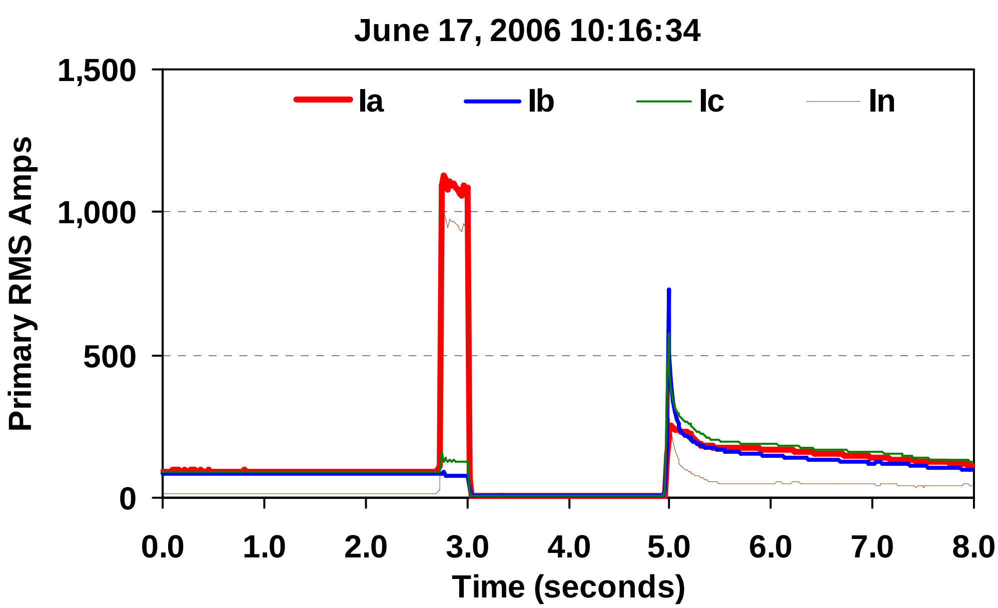


Figure 3-5
Third Episode of Recurrent Fault, One Week Later

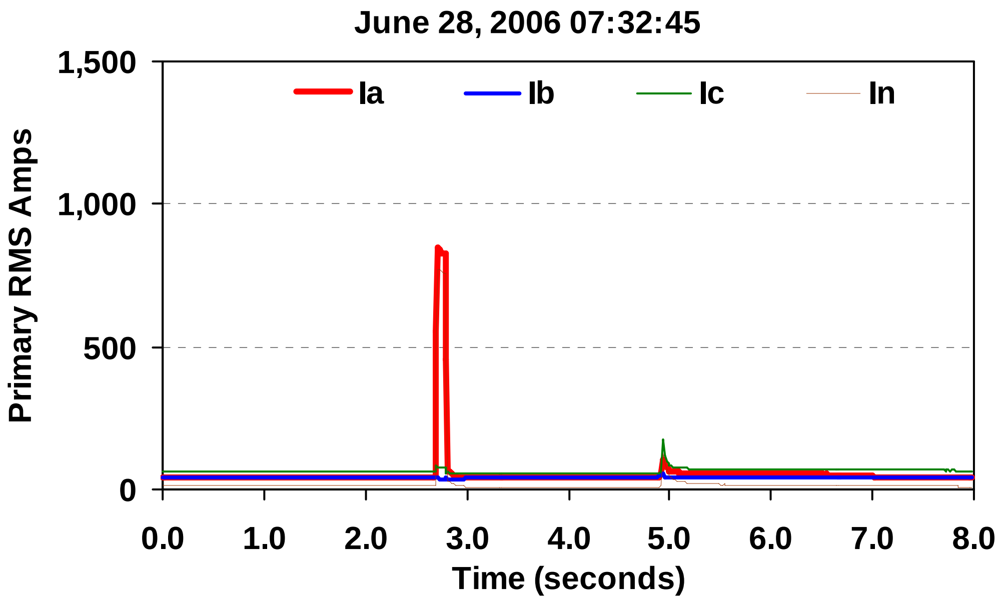


Figure 3-6
Unrelated Fault during Period of Interest

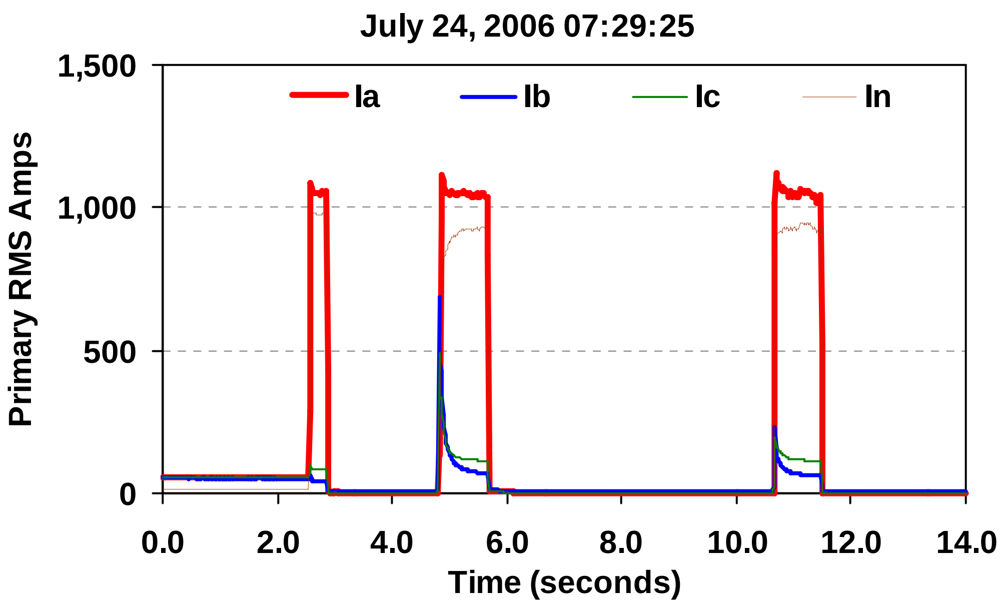


Figure 3-7
Sixth and Final Episode of Recurrent Fault, Seven Weeks after First

Case Study #3: Substation Cable Failure

A substation with a DFA prototype has 25 feeders, eight of which are monitored by the DFA. The substation has multiple, large, step-down transformers to provide 12.47-kV distribution. Substation cables run from the 12.47-kV terminals of each substation transformer into the substation control house, where they serve as the supply for multiple feeders (see Figure 3-8).

Shortly after 11:00 AM on the day in question, there was a violent failure in one of the substation cables, in the ductwork between one of the transformers in the substation yard and the control house. This failure caused a fault and resulted in additional damage that ultimately required tripping all of the substation's feeders. This resulted in an outage affecting 26,000 customers for several hours.

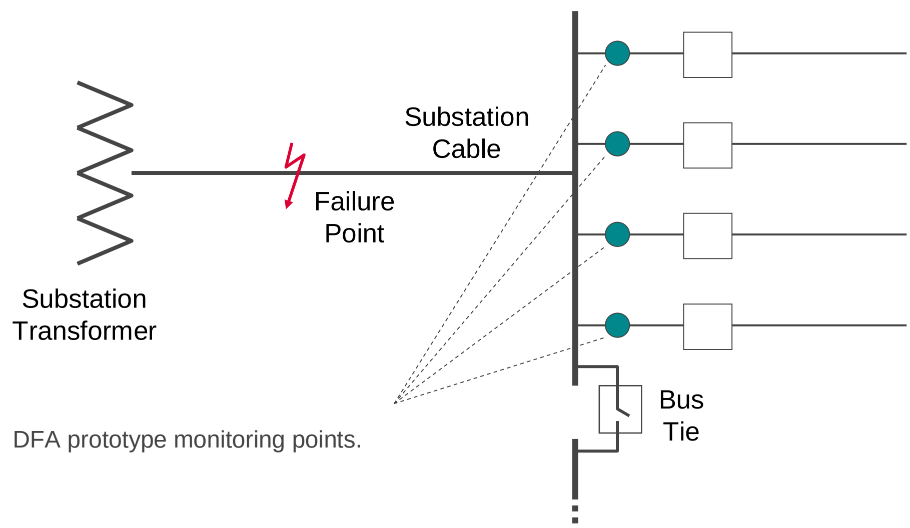


Figure 3-8
Diagram of Substation and Monitoring Points

Figure 3-9 shows the RMS bus voltages measured during the cable failure. The phase-A voltage dropped precipitously to 69% of nominal when the failure began and stayed at roughly this level for 2.1 seconds, at which time substation protection tripped the transformer. During the faulted period, the phase-B and phase-C voltages experienced swells to 118% and 112% of nominal, respectively.

Interestingly, 13 cycles after substation protection tripped the transformer and removed power from the faulted cable, the voltage returned for approximately 1-1/2 cycles. Analysis indicates that the voltages during this period of 1-1/2 cycles were roughly the same as during the 2.1-second fault period (i.e., approximately 69%, 118%, and 112% of nominal, respectively). It is believed that the normally open bus tie switch closed automatically in response to the transformer tripping off. This momentarily fed the fault from another substation transformer for 1-1/2 cycles.

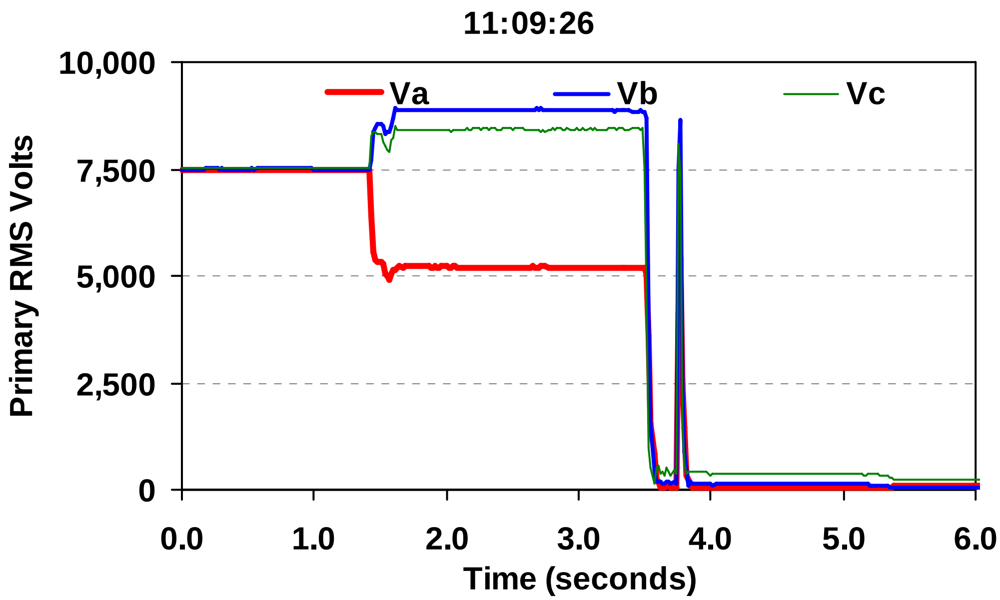


Figure 3-9
Voltages during Cable Failure

Figure 3-10 shows anomalous voltage readings at 11:07:38, approximately 110 seconds before the final cable failure. Over a period of just over one-half second, the voltage experienced multiple dips. Over the next 80 seconds, there were four other distinct times at which voltage anomalies occurred, one of which is illustrated in Figure 3-11. Then, 108 seconds after the initial anomalies, the ultimate fault of Figure 3-9 began, resulting in the transformer tripping 2.1 seconds later. In summary, voltage perturbations and anomalies related to this failure were recorded at each of the following times:

- 11:07:38 – Multiple significant voltage dips recorded at bus (Figure 3-10)
- 11:07:47 – Voltage dip recorded at bus
- 11:08:36 – Voltage dip recorded at bus
- 11:08:52 – Voltage dip recorded at bus (Figure 3-11)
- 11:08:58 – Voltage dip recorded at bus
- 11:09:26 – Sustained voltage dip (final fault), followed by trip 2.1 seconds later (Figure 3-9)

The DFA has recorded multiple episodes of distribution cable failures. It also has recorded precursors prior to many of those episodes. The elapsed time between first detecting precursors and final cable failure varies considerably. In some cases, no precursor activity is detected prior to the failure. A significant number of the cases, however, show advance warning periods that range from a few minutes to a few hours to a few days. There have been instances in which the warning period has been multiple weeks.

This substation-cable failure represents new knowledge in the DFA database. This type of event is statistically infrequent, but a single event significantly impacts reliability figures. A 26,000-customer outage for 2-1/2 hours adds 26,000 customers x 2.5 hours x 60 minutes/hour = 3,900,000 customer-minutes to calculations of reliability indices such as SAIDI.

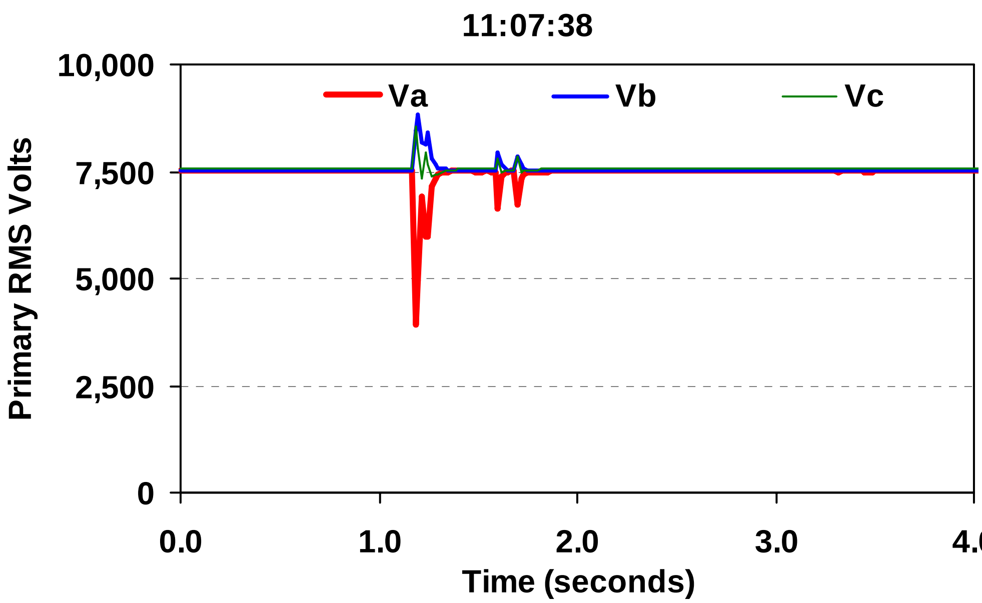


Figure 3-10
First Voltage Anomaly Preceding Cable Failure

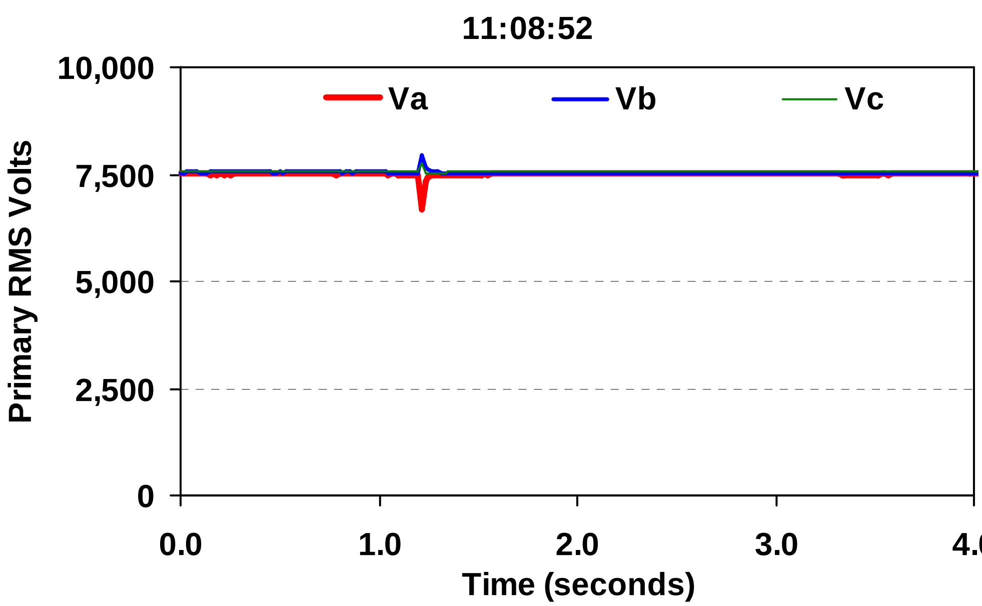


Figure 3-11
Fourth Voltage Anomaly Preceding Cable Failure

The initial intent of DFA technology has been to detect failures and incipient failures on distribution feeders. It monitors feeder currents and voltages to perform this function. Bus voltages and feeder voltages are effectively the same quantity when measured at the substation level, so the typical DFA installation uses voltage inputs from bus PTs (potential transformers). When an anomaly occurs on a feeder that the DFA monitors, it sees the currents and voltages related to that anomaly. When an event occurs on a feeder that the DFA does not monitor, the DFA still may see a voltage perturbation if the event is significant and draws enough current to affect the bus voltage noticeably, although the current drawn by the event is not available to the DFA. A similar situation exists when an event occurs on the substation bus or upstream of the bus (e.g., at the substation transformer or on the transmission system that feeds the substation transformer), in that significant events can affect the bus voltage sufficiently to be detected and recorded by the DFA.

The subject failure occurred in the cable upstream of individual distribution feeders. It caused voltage perturbations sufficient to trigger the DFA, although the DFA did not have access to measurements of the current being drawn directly by the failure and fault. The recorded patterns in the voltages were quite informative. Voltage characteristics before and during this substation-cable fault were similar to voltage characteristics before and during multiple recorded examples of incipient failures of cables serving end customers. This is significant, because it seems reasonable to extrapolate from this incident, to say that it is likely that failures of substation cables like this one may behave similarly to distribution cables that serve end customers. If that is true, then full deployment on all feeders might make it possible to detect similar failures in the future. If DFA-monitoring of all feeders indicates perturbations in the bus voltage that are characteristic of cable failure precursors, but none of the monitored feeders indicate that the failing cable is downstream of the substation, the failure may be presumed to be in the main substation cable. As has been noted, recorded examples of cables serving end users have shown that incipient failures often produce detectable precursors hours or days before final failure. This amount of warning period could prove sufficient for a utility to take preemptive action to avoid the significant damage and extended outage that accompanied the subject failure.

Another interesting observation about this case regards the amount of information, or lack thereof, that a utility often has in distribution substations. Other than the DFA, the utility in this case had no other electrical information to help it perform a root-cause analysis for this catastrophic event. Information like this is critical to the proper understanding of what went wrong, what worked, and what did not. This is a concrete example of one of the many uses for which utility companies use DFA data, in addition to the benefits of anticipating failures.

Case Study #4: Repeated Outage Following Cable Failure Misdiagnosis

Customers reported an outage on the evening of April 2, 2006. A technician responded and found a blown fuse on a section of primary-voltage URD (underground residential distribution) cable. In accordance with common operating practices, he replaced the fuse. It blew again shortly thereafter and he again replaced it. The fuse held this time, so he left the scene with service restored to all customers. There was no visible sign of damage, and there had been storms in the area around the time of the outage, so the trouble ticket was closed with an assumed cause code indicating lightning as the culprit.

Early on April 5, 2006, the same customers experienced another outage. The same fuse that was blown three days earlier was blown again. It was not possible to simply replace the fuse to restore service this time. The cable was found to be defective and customers were out of service for eight hours while repairs were made.

The feeder with the subject cable was instrumented with a DFA prototype at the substation. The DFA recorded the initial failure. It also recorded a second fault waveform approximately one hour later, when the technician first replaced the fuse. Both instances produced current waveforms that were characteristic of URD cable failures seen in the past, and they were recognized as such. The technician did not have this information available to him, however, resulting in the incorrect on-site diagnosis and the premature closing of the trouble ticket.

Figure 3-12 illustrates waveforms recorded at the time of the initial outage. Several hours after the initial service restoration, the DFA recorded the precursor activity shown in Figure 3-13. This measurement indicated characteristics of imminent cable failure, but no outage resulted. Another episode (not shown) occurred on the afternoon of April 3, some 18 hours after the first episode. This episode also was characteristic of a cable nearing failure, but again no outage occurred.

There was no further activity until three days after the initial fault, at which time the DFA recorded additional cable precursors that culminated in the final failure of the cable. Figure 3-14 illustrates current recorded during this final failure.

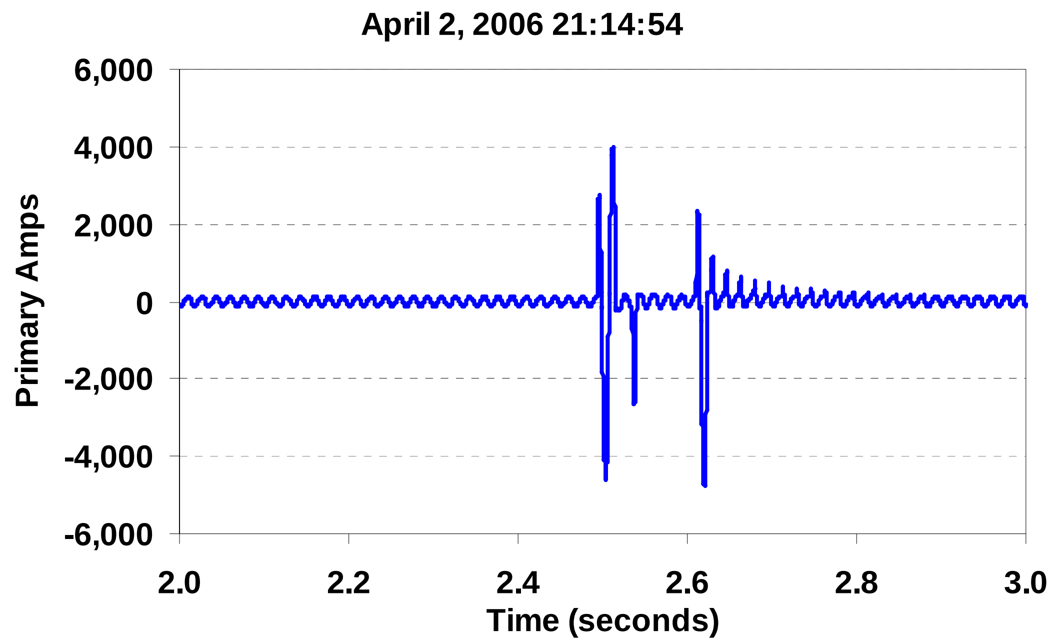


Figure 3-12
Current Waveforms at Time of Initial Outage

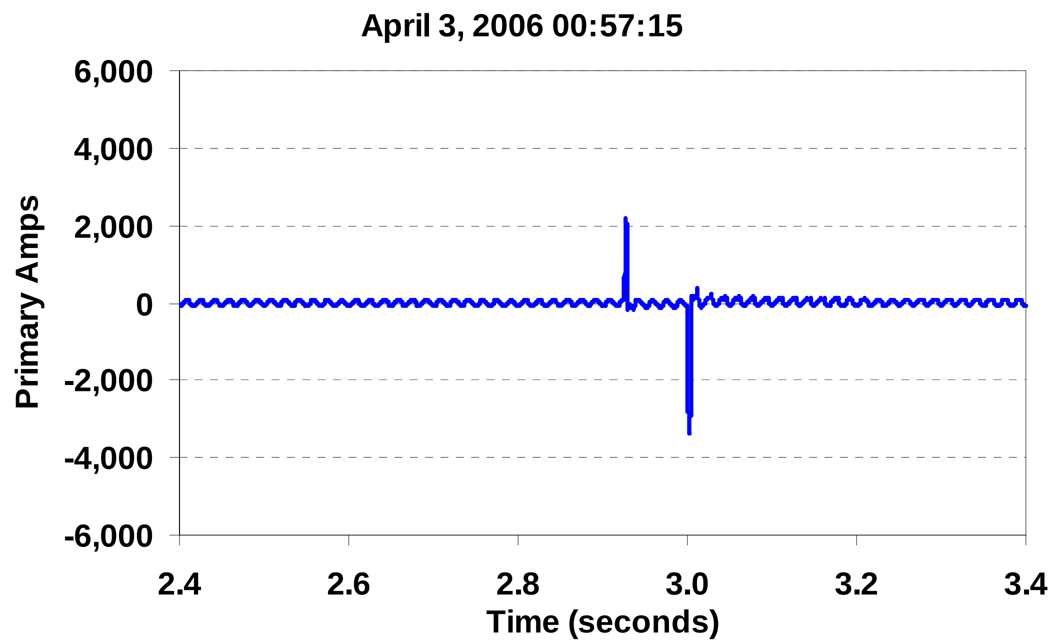


Figure 3-13
Precursor Signals Several Hours after Initial Outage

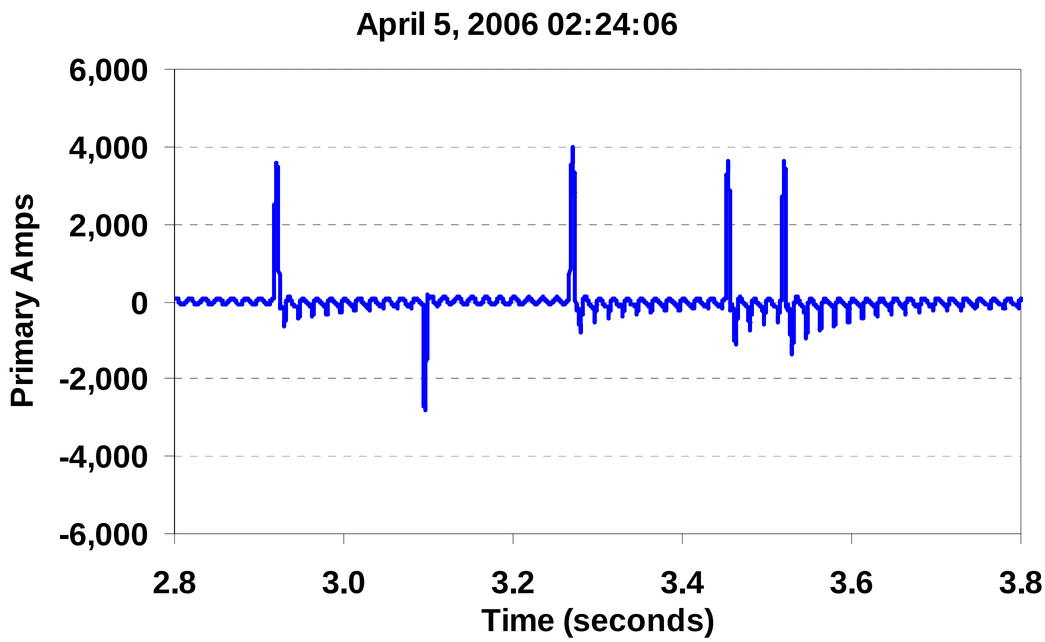


Figure 3-14
Final Failure of Cable, Three Days after Initial Outage

This case illustrates an interesting use of DFA technology. The initial failure on April 2, 2006, provided little warning period before the outage. However, recorded waveforms were indicative of a failing cable. Armed with this knowledge, a technician could respond differently. He still might attempt to replace the fuse, to restore service to customers quickly. However, he would not blame lightning and close the ticket, but rather would put the cable on a priority repair list. That would allow a crew to test the cable and make repairs during the multi-day period between the initial failure and the final outage.

The additional precursor activity during the next 24 hours also provides an opportunity to respond differently. In the subject case, the technician saw no apparent cause for the fuse to be blown, and he knew there had been storms in the area. He took the reasonable steps of replacing the fuse, determining that service was restored, and closing the ticket with an attribution to lightning as the presumed cause. If the utility knows this, but then has additional signs of incipient cable failure over the next several hours, it becomes clear that the probable cause is that the cable is nearing permanent failure. They can take appropriate action to schedule a repair, to avoid the eight-hour outage that occurred in the middle of the night two days later.

Case Study #5: Anomalous Feeder Breaker Operation

Figure 3-15 illustrates a phase-B fault that drew approximately 3,400 amps. The feeder breaker tripped in 39 cycles and reclosed 3.6 seconds later. The fault did not persist, no customers reported an outage, and the utility found no cause for the fault. Weather conditions were fair.

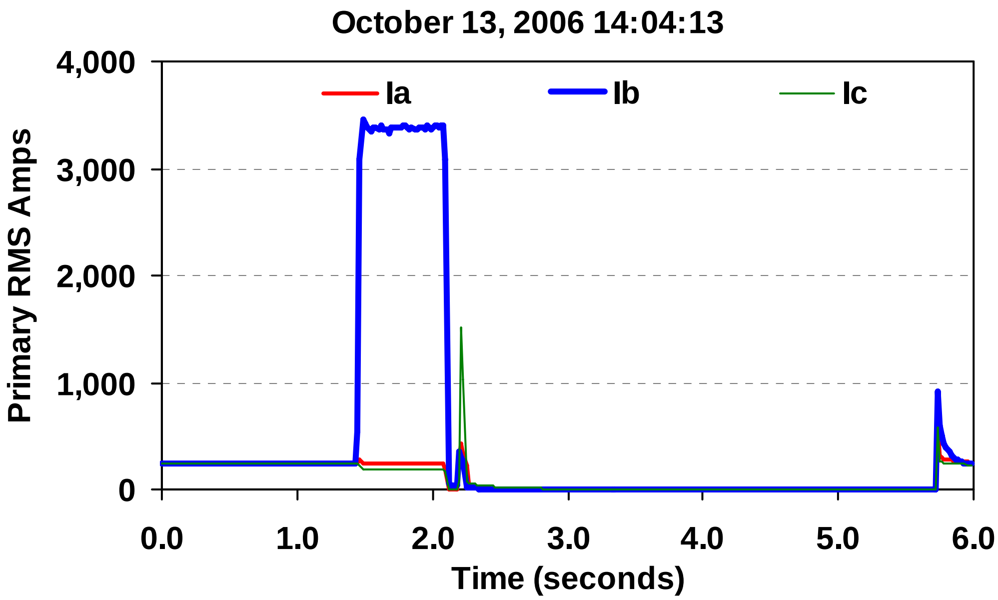


Figure 3-15
Single-Phase Fault Cleared by Feeder Breaker Trip and Reclose

At first glance, there is nothing remarkable about this sequence of events. Something caused a temporary fault that was successfully tripped and reclosed by the feeder breaker, with no customer outages resulting. Upon closer examination, however, the data shows a short-lived current "pulse" shortly after the breaker tripped.

Figure 3-16 shows the waveforms associated with the fault and the current pulse. Figure 3-17 shows greater detail for the portion of the waveform containing the pulse. The current pulse began 100 milliseconds after the breaker opened and lasted about 2-1/2 cycles.

This did not represent intended operation of the protection system, so the utility investigated possible causes for the observed behavior. This substation uses electromechanical protection and has no devices that record data of use in this investigation, other than the DFA prototype.

The utility believes a possible explanation is that the feeder breaker's reclosing relay closed its contacts while the overcurrent relay's trip contacts were still engaged. This caused the breaker to reclose but to immediately trip again. The utility subsequently examined DFA records for prior operations of that breaker, and found that it had experienced a similar episode six months earlier. Multiple additional episodes have occurred since. Each case involved a fault whose magnitude was small enough to allow the fault to persist for tens of cycles before tripping the breaker. The extra "pulse" has not occurred for faults large enough to operate the breaker in a few cycles. This observation supports the explanation initially proposed.

This case demonstrates how DFA data can be used to identify anomalies and problems involving system protection. The utility can use this information to determine how the system is performing and what, if any, remedial action should be taken to prevent improper operations.

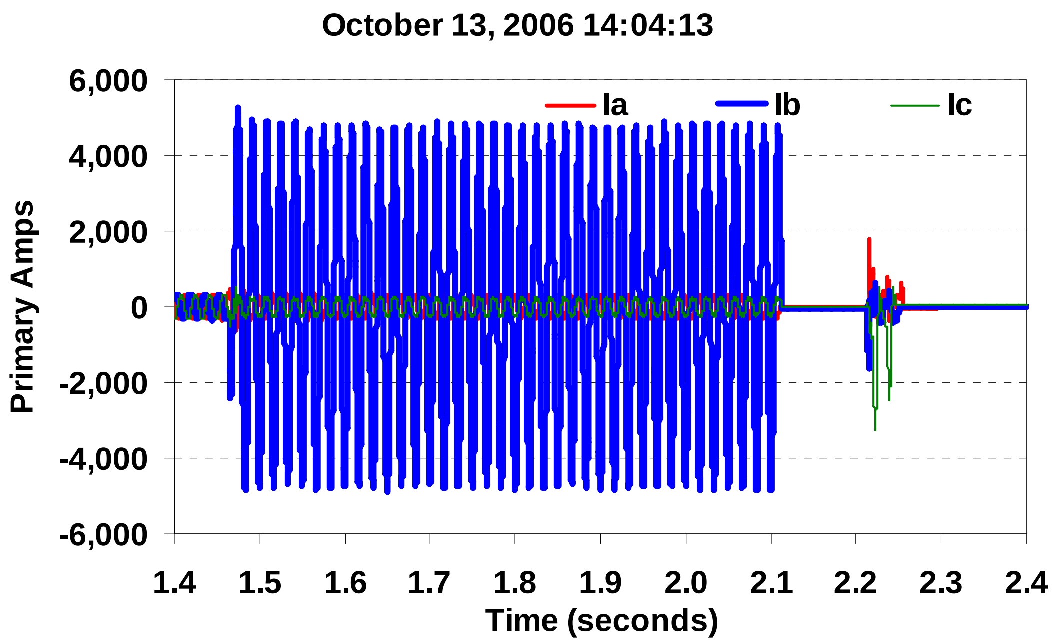


Figure 3-16
Single-Phase Fault with Short-Lived "Pulse" of Current after Breaker Tripped

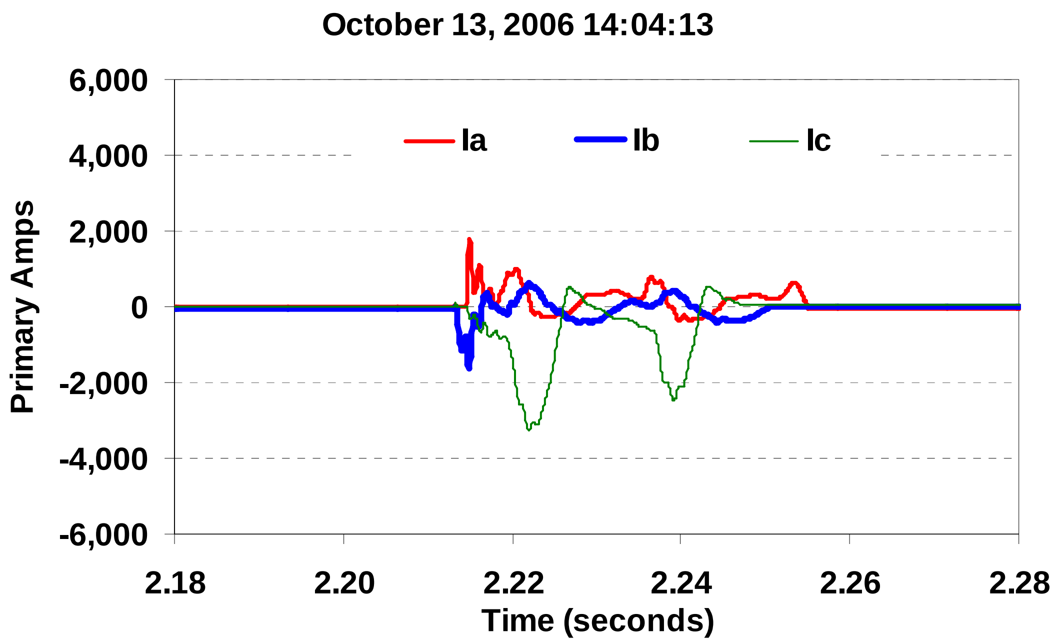


Figure 3-17
Detailed View of Current "Pulse"

Case Study #6: Improper Recloser Operation

Figure 3-18 shows RMS current measured during a permanent fault that was caused by a tree limb falling across a three-phase primary. The subject recloser is a three-phase device that is configured to lock out after four trips, two on its fast curve, followed by two on its slow curve. An overcurrent fault and trip occurred just before the 50-second mark in Figure 3-18. The recloser performed its first fast-curve trip, and then closed two seconds later. Fault current resumed a few cycles later. The recloser performed its second fast-curve trip, and then reclosed 30 seconds later, as it is programmed to do. Fault current resumed a few cycles later, and the recloser tripped a third time, this time on its slow curve.

To this point, the recloser operated in accordance with its configuration. However, the recloser failed to reclose after the third trip. Apparently, contacts on electronic cards in this type of recloser sometimes fail to make sound electrical connection, because of corrosion or improper seating. Failure to close in this case meant that the recloser was open but had not finished its sequence, and had not locked out. A responding crew likely would assume that recloser was locked out; when in reality it was in a state in which it could close and energize the feeder at any time. This is an obvious safety hazard for the crew, if they are not diligent to manually lock the recloser open before beginning repairs.

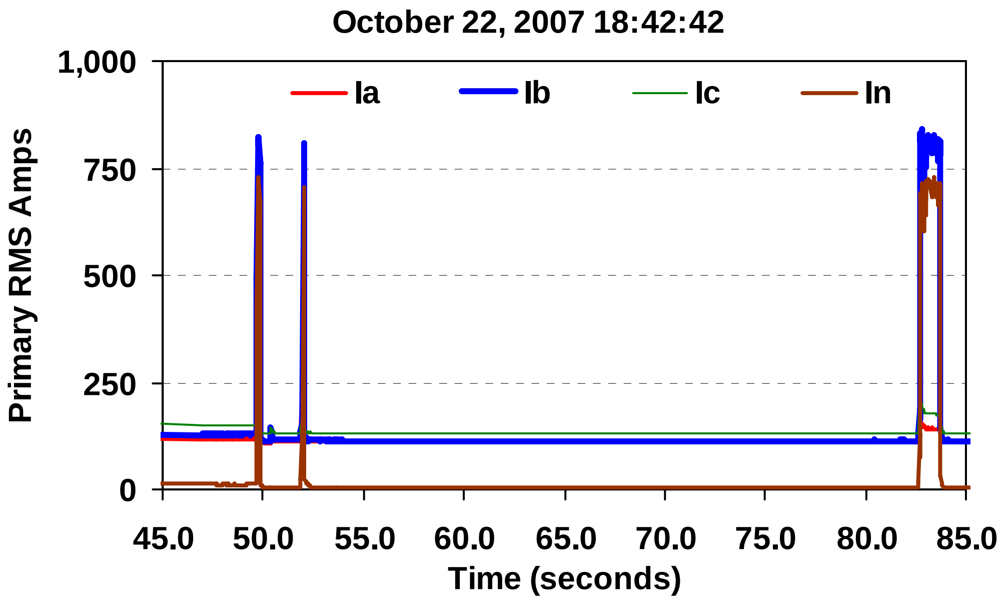


Figure 3-18
Permanent Fault in which Recloser Failed to Complete Sequence

Case Study #7: Fault-Induced Conductor Slap

Fault-induced conductor slap, or clash, occurs when electromagnetic forces cause sufficient relative motion of conductors to cause them to touch one another, or approach one another closely enough for flashover [1]. A typical scenario involves a phase-to-phase fault at some point on an overhead feeder (see 'Initial Fault' in Figure 3-19). The cause of the initial fault is not material to this discussion. The fault causes substantially equal fault currents to flow, in opposite directions, in two parallel phase conductors. This occurs over the entire length between the substation and the fault. Parallel conductors carrying currents in opposite directions experience repulsive electromagnetic forces that push them away from each other. Significant fault currents can produce enough force to move the conductors a substantial distance away from each other. On the return swing, conductors may contact each other or come close enough to induce flashover, as illustrated as a 'Conductor Slap (Second Fault)' in the figure. Where there is a properly coordinated mid-point recloser upstream of the initial fault, it may clear that initial fault and preclude the need for a feeder breaker operation. However, several scenarios can cause additional operation(s) of either the mid-point recloser or even the feeder breaker.

- If conductor slap occurs between the mid-point recloser and the initial fault point, and the slap initiates and separates after the mid-point recloser opens but before it recloses, there will be no fault current and no significant consequence.
- If conductor slap occurs between the mid-point recloser and the initial fault point, and the slap occurs after the mid-point recloser has tripped and reclosed, the mid-point recloser will see a second fault and will need to trip again.

- If conductor slap occurs upstream of the mid-point device, it will cause a fault that will require protection farther upstream (e.g., the feeder breaker) to operate. This is true without regard to any operation of the mid-point recloser.

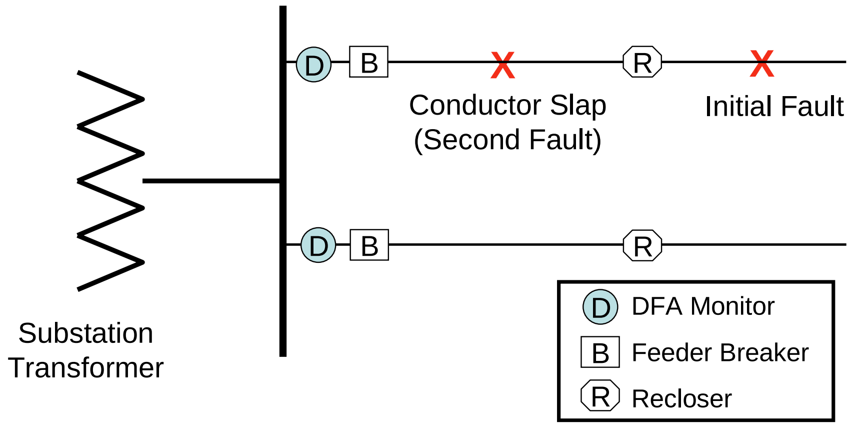


Figure 3-19
One-Line Diagram of Typical Fault-Induced Conductor-Slap Scenario and Monitoring

DFA prototypes have recorded multiple conductor-slap incidents. Figure 3-20 illustrates substation-based current measurements from one such event. Animal contact initiated a single-phase fault near the 2.8-second mark in the figure. At the 3.0-second mark, the fault evolved into a phase-to-phase-to-ground fault, and near the 3.3-second mark, it evolved further into a three-phase-to-ground fault. The subject feeder did not have a mid-point recloser, so the primary protection for this fault was the feeder breaker. It tripped at about the 3.5-second mark, and then reclosed 1/4 second later. The 1,550-amp spike in current at the 3.75-second mark is not fault current, but rather an inrush transient of the kind routinely caused by reclosing events.

Up to this point, there was nothing remarkable about this event: a single-phase fault evolved into a multi-phase fault and caused the feeder breaker to trip and reclose, just as it is designed to do. About 1.5 seconds after the reclose (i.e., the 5.25-second mark in the figure), however, a second fault occurred. The second fault began as a phase-to-phase fault, which evolved to include neutral and finally all three phases, tripping the feeder breaker a second time near the 6.1-second mark. The feeder breaker reclosed several seconds after the time period of the figure.

The figure shows that the phase-to-phase portion of the second fault produced more fault current (approximately 3,100 amps) than the phase-to-phase portion of the initial fault (approximately 2,850 amps). A utility engineer investigated and found that the initial fault was at a location on the feeder that was incapable of producing 3,100 amps. He then compared the phase-to-phase and three-phase fault currents measured during the second fault episode, to fault currents predicted by existing system fault studies. The studies indicated a single location that was capable of producing the fault currents of the second episode. The location was where the feeder crosses a major roadway, and therefore has atypical construction, including a longer-than-usual span. Precisely at the indicated location, the engineer was able to see pitting on the overhead conductors, supporting a conclusion of likely conductor slap. At the writing of this report, further investigation was being planned.

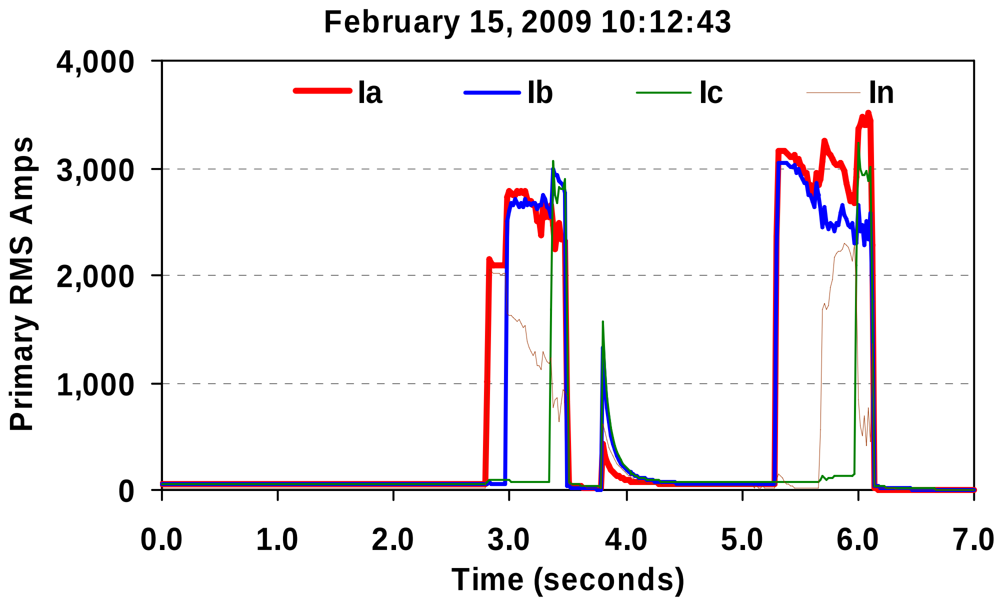


Figure 3-20
Animal Fault Followed by Conductor-Slap Fault (RMS)

A DFA prototype at another utility identified likely episodes of fault-induced conductor slap. This subject feeder was configured as in Figure 3-19, and included a mid-point recloser. The initial fault occurred past the mid-point recloser, which tripped and reclosed to clear the initial fault. A second fault occurred while the mid-point recloser was open. The second fault was phase-to-phase and of larger magnitude than the first, and it caused the feeder breaker to operate. This sequence of events occurred multiple times over a period of weeks, indicating that 1) something past the mid-point recloser was causing recurrent faults, and 2) fault-induced conductor slap was occurring upstream of the mid-point recloser, necessitating operation of the feeder breaker on each occurrence. The utility conducted an initial investigation, but unfortunately, those activities were not well documented and now are lost to the passage of time.

Case Study #8: Wind-Induced Conductor Slap

A DFA prototype registered two unusual faults, which each started as a rather low-level (i.e., 600 amps) phase-C fault that evolved into a more significant fault after a few tens of cycles. The two episodes were only a few minutes apart. Each required a single operation of the feeder breaker. The first is illustrated in Figure 3-21, with the initial, low-current interval shown circled.

The unusual signature, and the recurrence after a few minutes, prompted the utility engineer to investigate. He noted that windy conditions existed at the time of the faults, and suspected possible wind-induced conductor slap. He compared fault-current studies to measured values supplied by the DFA, and initiated a search. Approximately six spans up the feeder and three spans down a lateral, he found slack-span phase conductors with sufficient sag to contact the proximate slack-span guy. Figure 3-22 shows the line construction in the damaged area, and Figure 3-23 is a close-up view of the conductor damage from the slap incidents, which makes it clear that DFA-initiated action prevented further damage and possible conductor burn-down.

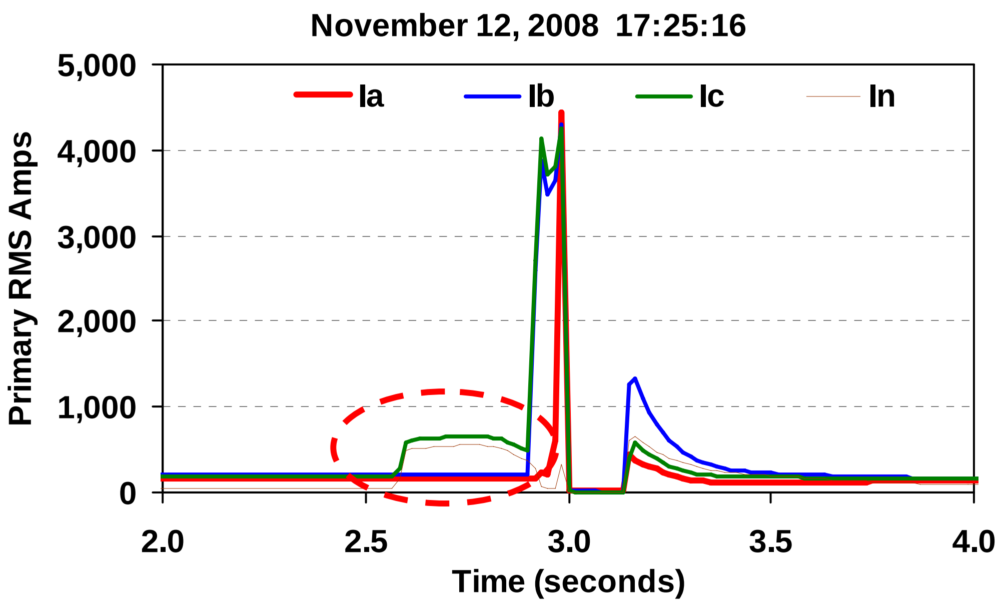


Figure 3-21
Unusual Fault Current That Prompted Investigation of Wind-Induced Conductor Slap

Figure 3-22
Photograph of Line Construction in Area of Wind-Induced Conductor Slap

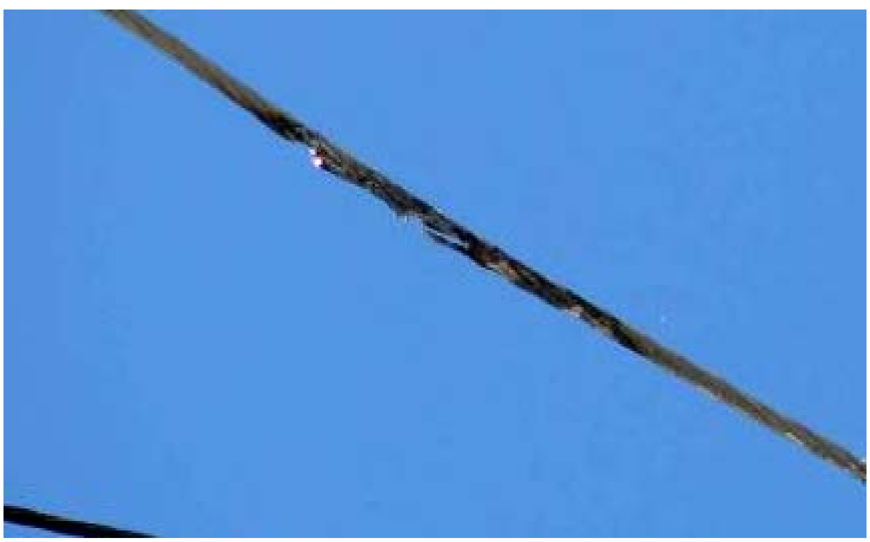


Figure 3-23
Photograph of Conductor Damage from Wind-Induced Conductor Slap

Case Study #9: Precursors Related to Internal Transformer Winding Failure

A DFA prototype intermittently registered subtle precursor signals dozens of times during the one-week period prior to the failure of a customer service transformer. Figure 3-24 illustrates one of the first of these measurements. The substation-measured load current was approximately 105 RMS amperes, and failure precursors caused intermittent five- to ten-ampere increases. Figure 3-25 shows the waveforms corresponding to the same episode. The circled region shows slightly accentuated peaks above the load-current envelope. This behavior was immediately recognized as indicative of an incipient failure, although the precise cause was unknown at the time.

Precursors occurred intermittently over the next seven days:

- 5/6/2007 – Multiple precursors recorded during a three-hour period starting 9 AM
- 5/7/2007 – No precursors recorded
- 5/8/2007 – No precursors recorded
- 5/9/2007 – One precursor recorded at 6:18 PM, another at 11:32 PM
- 5/10/2007 – No precursors recorded
- 5/11/2007 – No precursors recorded
- 5/12/2007 – Multiple precursors recorded during the two-hour period starting 6 AM
- 5/13/2007 – Multiple precursors recorded 8:08 AM – 9:39 AM

Customer reported an outage at 9:40 AM on May 13, 2007, which corresponded with the time of the final precursor listed above. That episode is shown in Figure 3-26.

The responding crew was not aware of information coming from the DFA prototype. At the customer's premises, they found a 25 kVA CSP transformer with its breaker tripped. They saw no obvious sign of a problem and reset the transformer. They left the customer location at 10:25 AM, with service restored. They closed the trouble ticket with a cause code indicating they suspected the transformer had tripped on overload.

Thirty minutes after the crew reset the CSP breaker and restored service, the DFA prototype began to register and record additional failure precursor activity. The first such episode following the service restoration is shown in Figure 3-27. Precursor signals occurred intermittently over the next hour, until the CSP breaker again tripped. Figure 3-28 illustrates signals recorded shortly before this second outage.

The crew visited the site again and again cited overload as the cause of the trip. This time, they replaced the existing 25 kVA transformer with a 35 kVA transformer. This solved the problem, but clearly for the wrong reason. Based on information from the DFA prototype, the utility subsequently pulled the transformer for further inspection.

There are several important observations and conclusions from this case.

- Transformer winding failures produced a unique signature. These signals were present well in advance (seven days) of the time at which customers were affected in any way. There was no indication of a problem from any other source.

- Location of failures and incipient failures has always been and remains a significant challenge, particularly for subtle conditions with limited current. The initial charge in the DFA project was to focus on proving the ability to detect and characterize failure signatures. The plan has been to explore location techniques after first detecting and characterizing the signals of interest. Traditional impedance calculations are meaningless in situations like the current case, because the primary impedance that determines incipient fault current levels typically consists of arc impedance, winding impedance, etc, not the line and system impedances that impedance-based location methods assume.
- As soon as the first outage occurred, location was no longer an issue. Imagine that a dispatcher knows the DFA has been measuring precursors indicative of a transformer winding failure on phase B of a particular feeder for the past week. Imagine further that he knows the level of precursor activity has been high for the past hour or so, but stopped suddenly coincident with a fair-weather outage call from a customer served by a phase-B transformer on that feeder. It is straightforward to recognize the probable connection between the two events and advise the responding crew to expect to find a transformer with a failed internal winding – a problem that typically will not be obvious from casual inspection.
- This was the first documented case of failure precursors for an internal transformer winding failure. Discovery of this signature and documentation of its cause enable similar future measurements to be recognized and investigated more effectively. Researchers believe it likely that DFA prototypes have recorded previous instances of transformer winding failures, but their causes were unknown at the time. The difficulty a utility faces when investigating unknown anomalies means that the causes of those past cases were not found.

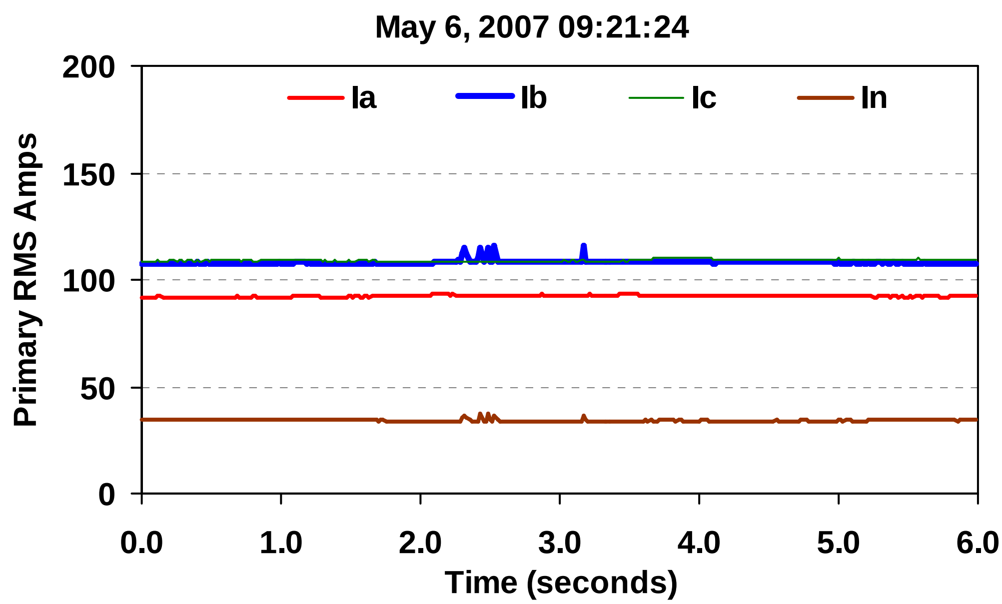


Figure 3-24
Precursors One Week before Transformer Failure (RMS)

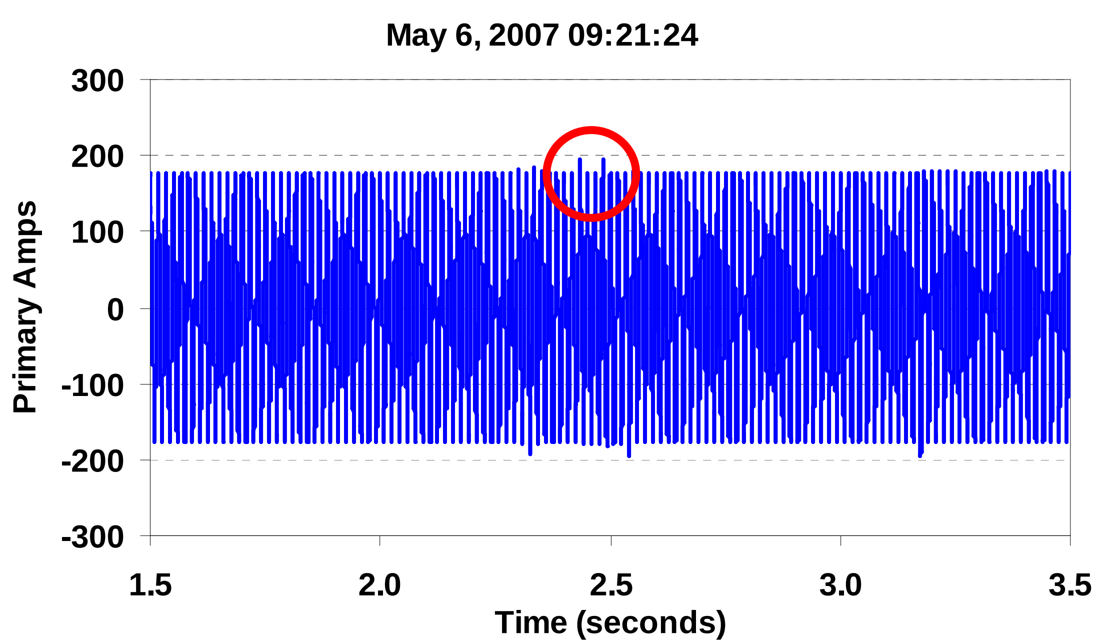


Figure 3-25
Precursors One Week before Transformer Failure (Waveforms)

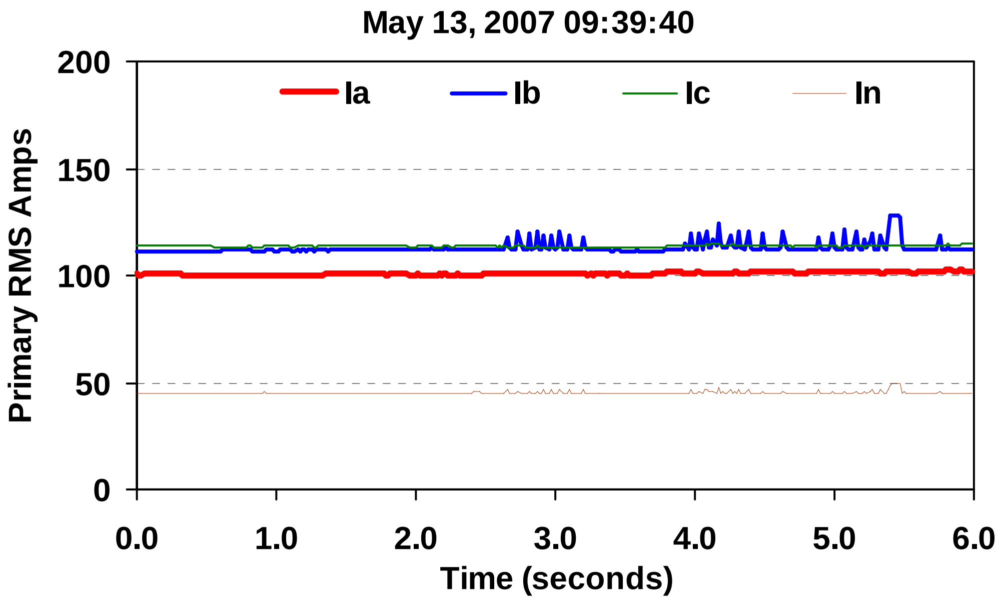


Figure 3-26
Precursors Immediately Prior to Initial Customer Outage (RMS)

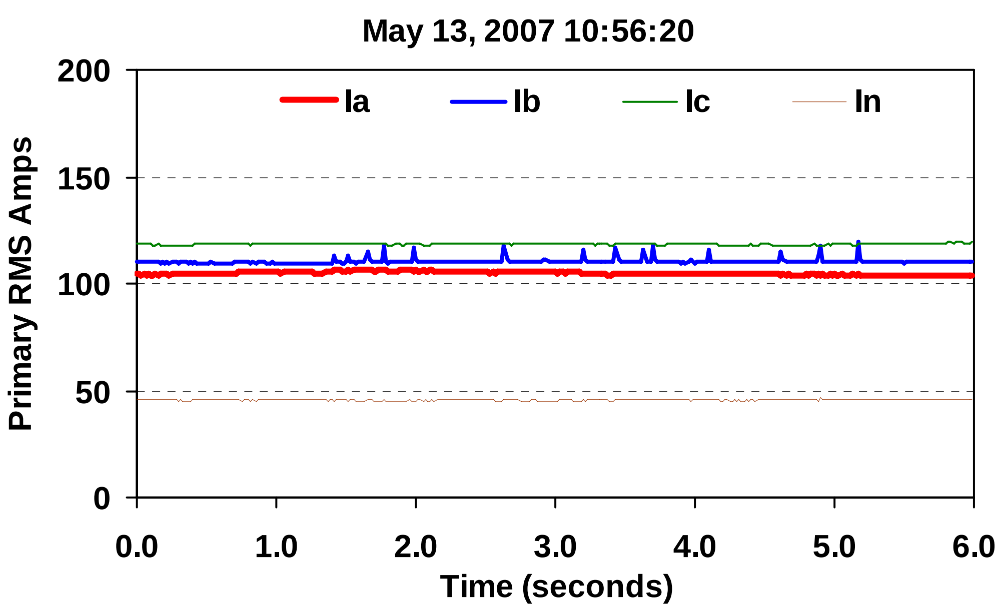


Figure 3-27
Precursors 30 Minutes after Crew Reset Transformer (RMS)

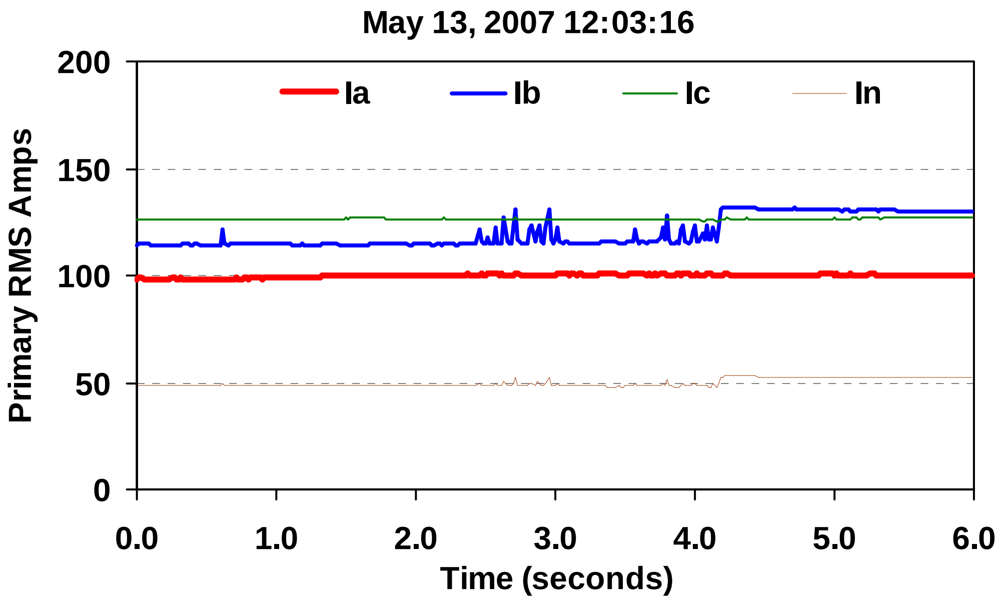


Figure 3-28
Precursors Preceding Second Trip (RMS)

Case Study #10: Internal Failure of Transformer Primary Bushing

A DFA prototype registered a one-cycle fault that tripped the feeder breaker. The breaker reclosed 45 cycles later and no sustained outage resulted. Figure 3-29 illustrates this fault. Five hours later, there was a second fault, similar to the first. As before, the breaker tripped and reclosed, and no sustained outage resulted. Figure 3-30 illustrates the second episode.

Nothing further occurred until six days later, when a third fault occurred. Figure 3-31shows the current measured at the substation during this episode. In this episode, fault current increased over a period of about two cycles, finally reaching a magnitude of several thousand amperes. The breaker tripped and reclosed, but the fuse on a transformer on the feeder operated before the breaker opened, and a localized outage resulted.

The utility responded to the resulting outage and found a failed transformer with a blown fuse. They subsequently had the transformer torn down and inspected. Figure 3-32 shows that the internal bushing had failed catastrophically. Findings can be summarized as follows:

- There was almost no oil in the transformer.
- When refilled with oil, a hole was identified where a tack weld on a cooling fin had failed.
- The secondary bushings were loose and could be moved by hand.
- The inside of the transformer was damp and corrosion was found in several places.

- The internal bushing that failed had a "rivulet" that the testing company believes to be either a manufacturing defect or the result of leakage and fault current over time.

As an aside, there was some question about the response of the overcurrent protection. In each episode, fault current ceased one-half to two-and-one-half cycles before the feeder breaker opened. A protection engineer for the utility confirmed that the relaying scheme is designed and configured such that all faults result in an instantaneous trip of the breaker. If a fuse or other downstream device operates before the breaker trips, the breaker trips anyway, but the fault does not resume when the breaker recloses and no further action is required. This was confirmed to be in conformance with the substation protection scheme implemented by the utility.

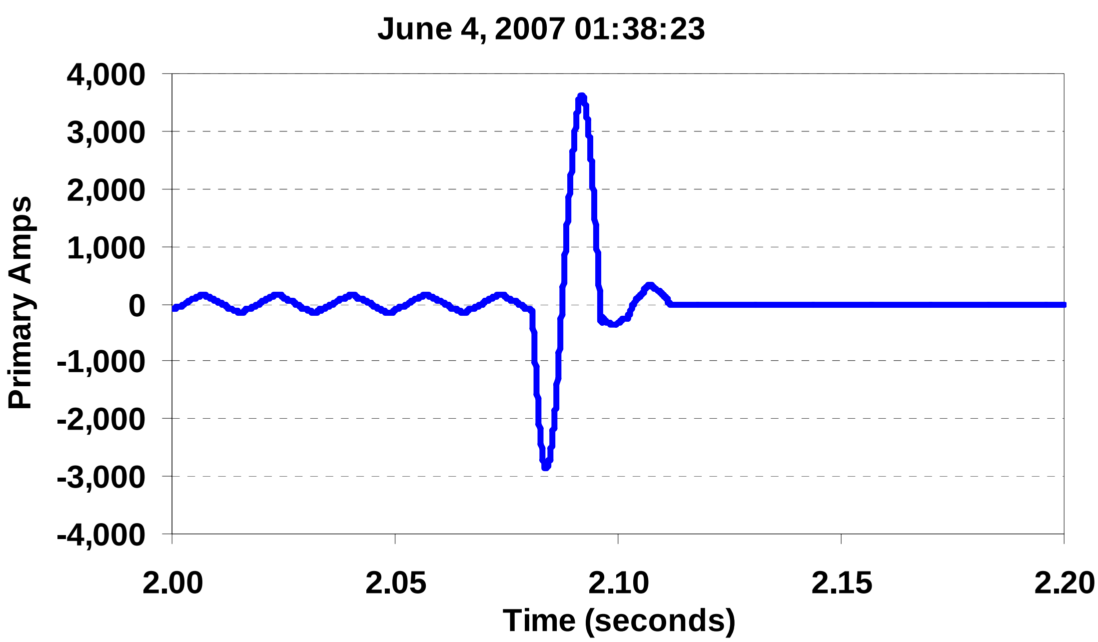


Figure 3-29
First Internal Flashover of Transformer Primary Bushing

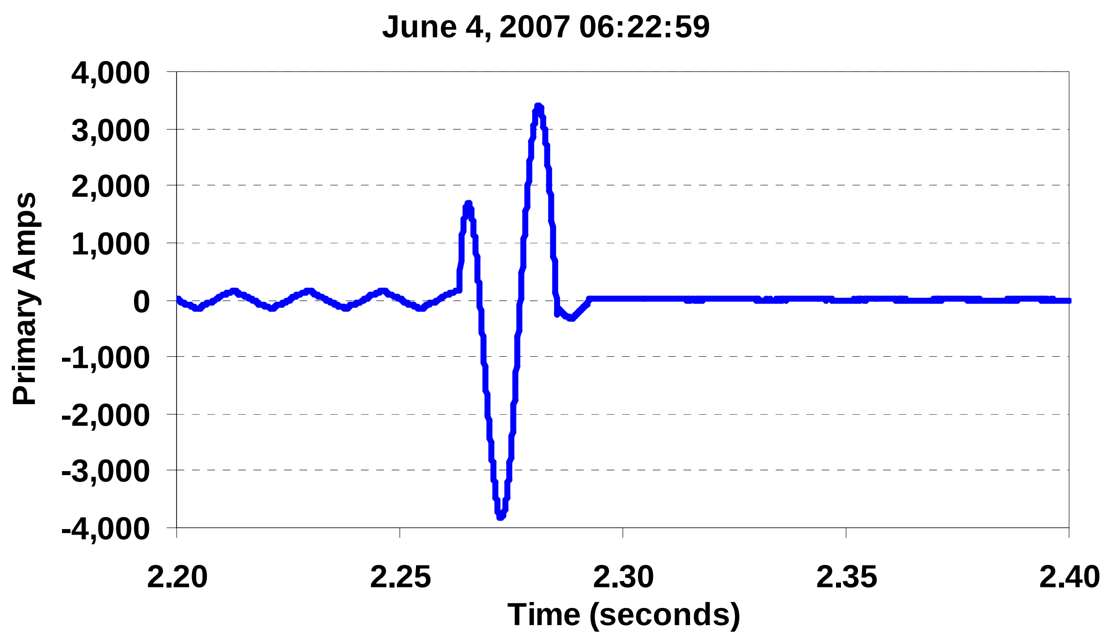


Figure 3-30
Second Internal Flashover of Transformer Primary Bushing

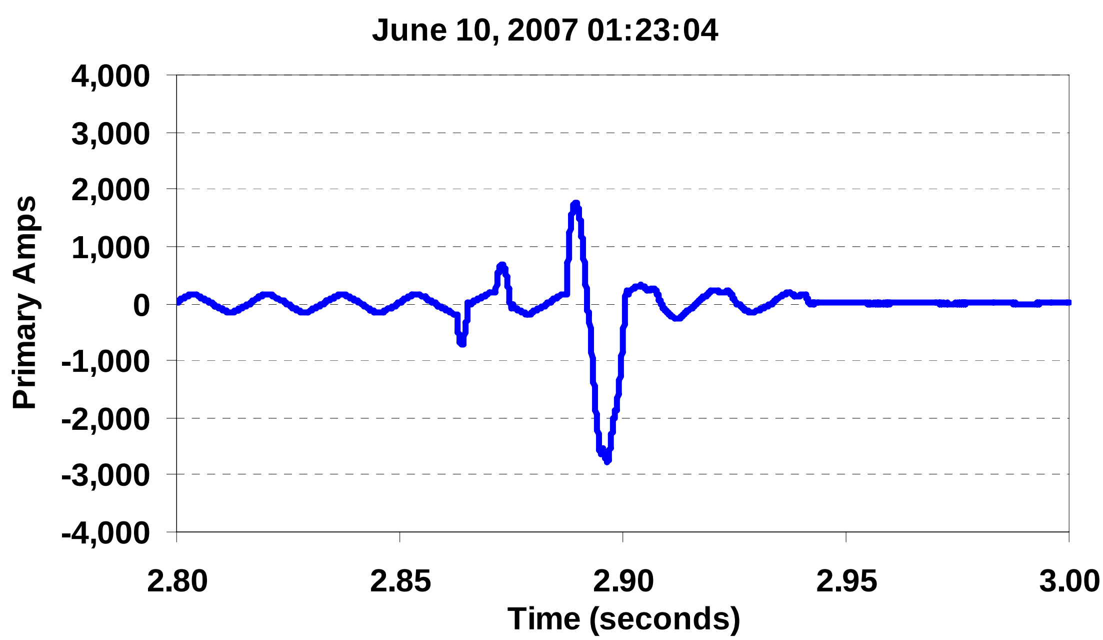


Figure 3-31
Final Internal Flashover and Failure of Transformer Primary Bushing

Figure 3-32
Failed Internal Transformer Bushing

Case Study #11: Capacitor Controller Malfunction (Extreme Case)

DFA prototypes have documented multiple cases in which capacitor controllers malfunctioned in such a way that they operate dozens or even hundreds of times per day, instead of the normal one or two times per day. Causes for such malfunctions have included electronic failures and incorrect settings. To study the natural progression caused by this kind of malfunction, one utility allowed such a problem to persist for a period of two months after learning that the problem existed from their DFA prototype. The capacitor operated more than 3,000 times over this 60-day period. The capacitor bank's switches were rated for only 1,500 operations and the excessive wear and tear resulted in internal failure of one of the switches. Prolonged arcing in the failing switch contacts caused significant, near-continuous transients for several days and resulted in failures, not only in the subject capacitor bank, but also in capacitor banks on the same feeder, and even on another feeder connected to the same substation bus. Other utilities have taken the approach of using the DFA prototype to actively correct problems, and they have identified and fixed similar problems within days of inception, thereby avoiding escalation of the problem and other failures.

Figure 3-33 illustrates the reactive power flow as a capacitor switched on a DFA-monitored feeder. There are two distinct items of interest here. First, only phase A shows a step change in reactive power, despite the fact that all capacitor banks on this feeder are configured to operate as balanced, three-phase banks. This indicates a problem with the bank, such as blown fuses or failed switches or control circuitry on phases B and C. This type of problems represents suboptimal operation and needs to be addressed by the utility, but the need is not urgent. Rather, it is the type of problem that likely should be reported on a daily or weekly list of capacitor problems, to be investigated and remedied in due course.

The second item is more interesting and more troubling. Prior to the time period illustrated in the figure, the capacitor had been energized continuously since switching ON earlier that day. At the illustrated time, the bank switched OFF, as indicated by a precipitous increase in reactive power on phase A. This is normal and can be caused by multiple control parameters, such as time-of-day, temperature, VAR flow, or line-voltage level at the bank. It is not normal, however, that the bank switched bank ON a few seconds later. It then proceeded to cycle OFF and ON periodically at intervals of approximately six seconds. It continued to cycle in this manner for the next 36 minutes, during which time it cycled OFF and ON approximately 350 times!

A touch of irony occurred several hours later, when a power supply in the prototype DFA monitoring equipment failed. This equipment had been in service in this location for several years. The fact that its power supply failed a few hours after the capacitor bank cycled 350 times is a good indicator that the hundreds of proximate transients caused failure of the power supply.

The repetitive switching stopped abruptly 36 minutes after it began. A cursory examination of the feeder did not reveal the problem, although a more thorough search might identify the culprit. There are at least two possible causes for a capacitor switching ON and OFF in this way. The switch itself could have mechanical failure, in which faulty contacts allow intermittent contact and conduction. Past experience in more than one instance has shown that this type of failure causes multiple transients per second, as sparking and low-level arcing occur between fouled contacts. The other is a malfunction of the controller logic or circuitry. The timing of the switching operations at precise, consistent six-second intervals makes this seem the more likely cause in the present case.

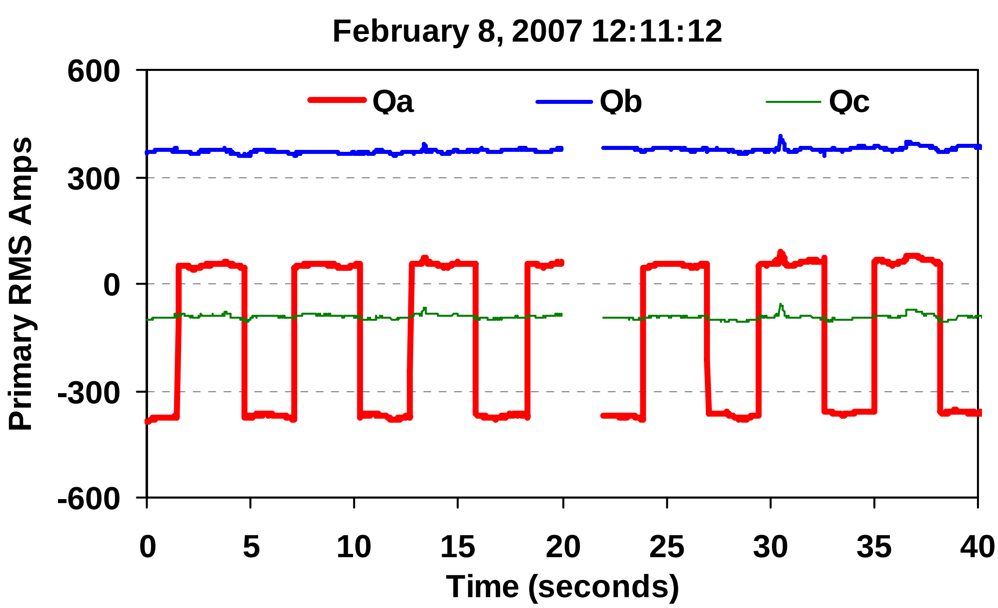


Figure 3-33
Malfunctioning Controller Cycling Capacitor Every Six Seconds

Case Study #12: Avoidable Main-Line Switch Failure

DFA prototypes have documented multiple failures of line switches, splices, and connectors. All are electrically similar events, in that each involves a poor in-line connection that is carrying load current. DFA prototypes have recorded multiple cases of this type of failure, and automatic algorithms can recognize their unique characteristics.

The present case study is a unique and interesting example of this type of failure, because it caused a substantial outage, and because the utility had other information indicating an old switch needed replacement, but did not have reason to treat its replacement with urgency.

In September 2007, an automobile accident damaged line equipment, requiring utility personnel to open line switches to energize the affected area and make repairs. The subject line switch was just outside the substation fence and carried virtually all feeder load. The crew had difficulty opening the switch. This was reported to the utility's reliability engineering group, which examined the switch shortly thereafter. The switch was found to be old and in need of replacement, but it was continuing to carry load current, so the need was not deemed urgent and replacement was placed on a routine work list.

On November 14, 2007, a fault occurred on the feeder with the subject switch. The underlying cause of that fault is immaterial to this discussion. It occurred at a position on the feeder for which the feeder breaker was the primary protection. The feeder breaker tripped and reclosed twice, and no permanent outage resulted for any customers. However, the subject main-line switch experienced the stresses of carrying the temporary fault current and the inrush transients of the reclosing operations. Substation-based RMS currents during this fault are illustrated in Figure 3-34, which shows that there was approximately 5,900 amps of fault current.

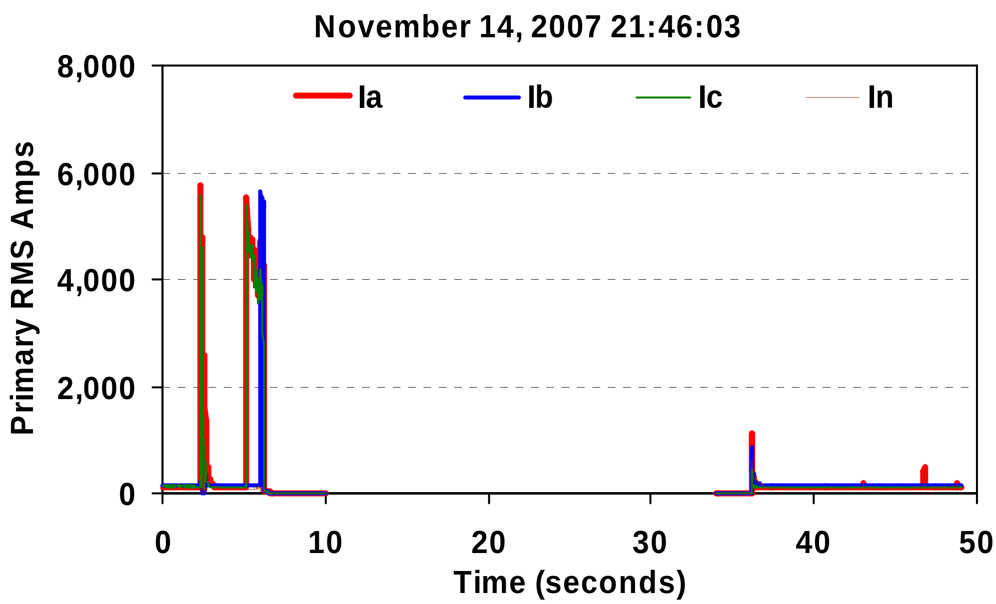


Figure 3-34
RMS Fault Current Requiring Two Trips and Recloses of Feeder Breaker

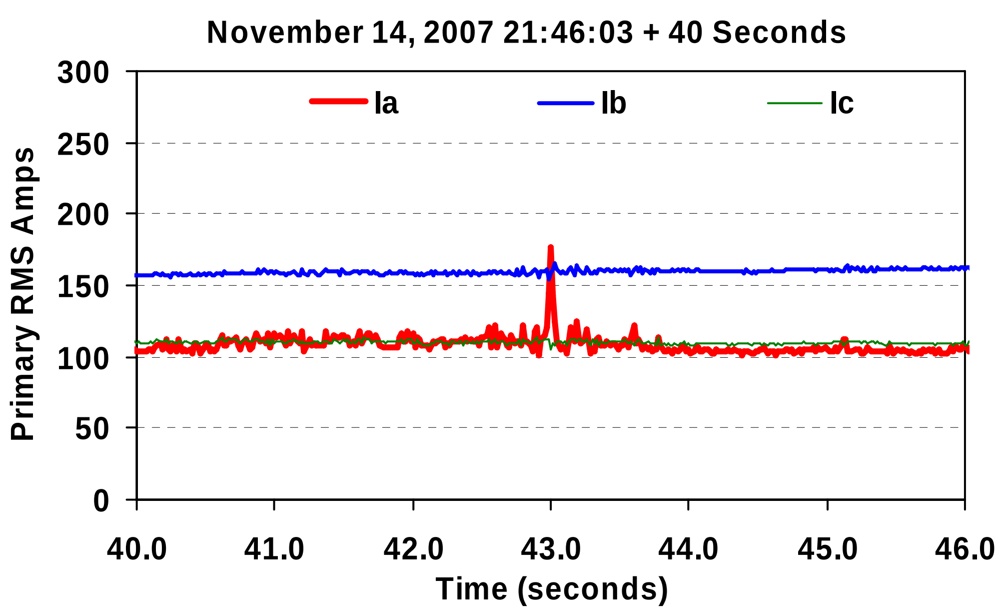


Figure 3-35
Anomalous RMS Current Shortly after Fault of Figure 3-34

Figure 3-35 shows substation-based RMS phase currents recorded shortly after the second reclose. The phase-A current is erratic. Detailed analysis revealed characteristics previously associated with in-line switch failures. However, because the DFA project was a research project, this information was not available to utility operations or reliability personnel, and no action was taken.

The erratic behavior in the phase-A current subsided in less than one minute. Approximately 1-1/2 hours later, a similar sequence occurred, again involving a high-current, evolving, multi-phase fault that required two trips and recloses of the feeder breaker. Again, no sustained outage occurred. Following this fault sequence, the erratic behavior in the phase-A current returned, only this time it was much more pronounced. It again subsided over the next minute or so.

Nothing further of interest occurred until a month later. Then, on December 15, 2007, another high-current fault occurred on the feeder. As before, its cause is immaterial to the discussion at hand. As in the November incidents, it produced thousands of amps of fault current and required two trips and recloses of the feeder breaker. The fault did not cause a sustained outage.

Immediately following the December fault, the phase-A current again exhibited erratic behavior. This time the erratic behavior did not subside over time, however. Instead, 1-1/2 hours later, the phase-A, main-line switch failed catastrophically, causing the feeder breaker to operate to lockout. The result was an outage to 294 customers that lasted approximately 2-1/2 hours (43,000 customer-minutes).

The entire sequence can be summarized as follows:

- September 2007 – Line crew had trouble opening switch. Reliability engineer inspected switch and put it on list for routine replacement.
- November 14, 2007 – High-current fault was cleared by feeder breaker, followed by switch-failure precursor signature in phase-A current. Entire process repeated later in evening, at which time failure signature was more severe. In each case, failure signature subsided within minutes.
- December 15, 2007 – High-current fault was cleared by feeder breaker, followed by switch-failure precursor signature in phase-A current. Later in the evening, phase-A switch failed catastrophically, requiring feeder breaker to operate to lockout, and causing a 43,000-customer-minute outage.

If a utility reliability engineer were presented with the September and November information (known-bad switch plus indication of incipient failure of a close-in switch), he could expedite replacement of the switch. The subject utility in this case believes that it would have avoided this outage altogether, if presented with this information.

Case Study #13: Reliability Improvement through Situational Awareness

This final case study involves a wildlife-induced fault, not an incipient failure. However, it is included here because it demonstrates an important concept from the *Evolution of DFA Premise* section of Chapter 1 (see page 1-2).

At 6:33 AM on October 25, 2008, a fault occurred on a DFA-monitored feeder. Using highly automated processes, the waveform was captured, analyzed, and summarized within minutes, making the following information available:

- Faulted phases: ABC
- Fault magnitude: 6 215 amps
- Protective operation: trip/blow, without reclose
- Per-phase load interrupted: A: 662 kW; B: 644 kW ; C: 635 kW (29%, 28%, and 30% of pre-fault load levels)

Automated techniques developed during the DFA project provide this information, automatically, with no human intervention. They do this based solely on analysis of waveforms recorded from conventional, substation-based CTs and PTs, without digital status inputs or communications with any device outside the substation.

Because 29% of the feeder load was lost, there is only one protective device on this circuit that could have been involved: the primary, fused switchgear for a specific shopping center. If this information were made available to dispatchers, it would be sufficient to dispatch a crew and provide very specific information about location. This could have happened by 6:45 AM.

Because the DFA system was part of a research project and not available to dispatch personnel, they had no indication whatsoever that a fault had occurred, until a customer at the shopping center called at 8:18 AM, a full 1-3/4 hours after the outage began.

A crew was dispatched shortly after 8:18 AM. They found that wildlife had gotten into the subject switchgear and blown all three 40-amp fuses. They made repairs and restored service at 10:03 AM. Ironically, the amount of time between the fault and the first customer call was the same as the amount of time between that call and the eventual service restoration. Had dispatch personnel had the information shown above at 6:45 AM, service restoration would have occurred much sooner and the outage would have been much short, probably by about one hour.

Concluding Remarks

Researchers continue to take advantage of the network of prototype DFA monitoring systems put in place during this project. They continue to capture high-fidelity recordings of waveforms from normal and abnormal events on 60 feeders at 14 substations across North America.

The monitoring systems provide additional examples of apparatus failure modes that already exist in the DFA database, thereby providing an opportunity to further assess characterization algorithms and to improve them when improper or suboptimal behavior is discovered. This results in more robust algorithms. The monitoring systems also continue to document failure modes that previously did not exist in the DFA database, offering opportunities to assess these new failures and implement or improve algorithms.

Case studies documented in this chapter provide multiple examples of the types of failures that the DFA detects. Except where specifically noted, none of the utilities involved in these cases had any information regarding the incipient failures, except from the DFA. Utilities are discovering potential and value in the anticipation of faults and failures. They also are discovering myriad uses for the data outside the initial purpose of anticipating faults.

The database now contains multiple examples of many common failure modes on distribution feeders. Ongoing efforts continue to gather data about additional failure modes that are statistically less common. It is important to note that failure modes that are statistically infrequent may have significant impact on system reliability when they do occur. The case study about the substation cable failure is a dramatic illustration.

Reference

1. Daniel J. Ward, “Overhead Distribution Conductor Motion Due to Short-Circuit Forces,” *IEEE Transactions on Power Delivery,* Vol. 18, No. 4, October 2003, pp. 1534 – 1538.

4
COMPLEMENTARY PROJECTS AND ACTIVITIES

EPRI supports the basic research behind Distribution Fault Anticipation (DFA) technology. This has been the primary means of demonstrating basic concepts, developing system integration concepts, and creating a library of waveform signatures related to apparatus failures, failure precursors, and malfunctions. Texas A&M has been and continues to be involved in parallel projects that are complementary to the ultimate objective of making DFA technology commercially viable and available. It is beyond the scope of this current report to provide detailed information about these parallel efforts, but it is appropriate and instructive to give the reader a cursory overview, to provide a better overall picture concerning the status and future of the technology.

Sensor Characterization

DFA prototype monitoring equipment uses conventional current and potential transformers (CTs and PTs) to derive its inputs from the power system. This is appropriate and in line with early direction to avoid expensive, specialized sensing or active sensing that injects signals onto the power system.

The *Sensing* section of Chapter 2 discusses the desirability of using non conventional sensors for DFA deployments in substations and in distributed feeder locations. The primary motivation is to achieve a total installed cost that makes widespread deployment more economically feasible than possible with conventional CTs and PTs. This applies to DFA technology and to present and future application of other advanced monitoring functions.

The Power Systems Engineering Research Center (PSERC) is funding a project to perform comparative characterization of multiple non conventional types of sensors. Texas A&M University leads this effort. The project will install multiple types of non conventional sensors electrically in parallel with conventional PTs. It will use DFA equipment that has been modified to accept low-energy inputs, to monitor the outputs of the non conventional sensors. An unmodified DFA unit will monitor conventional PTs to provide a basis for comparison. This is a voltage-only comparison. Similar types of comparisons are needed to quantify current sensors.

Waveform data will be collected when normal and abnormal events occur naturally on the subject feeder. The data will be retrieved and analyzed. The result will be a comparative characterization of the various non conventional sensors and conclusions about their ability to provide appropriate sensing for sensitive, advanced functions.

Pilot Demonstrations

The United States Department of Energy (DOE) funded a project to perform pilot installations of systems based on DFA technology. Pilot installations began in 2008 and are ongoing.

Under this project the DFA prototype that was designed, implemented, and deployed in the Phase II EPRI project was adapted and implemented in a commercial-beta system. This involved making hardware components for field installation more modular and rugged, and moving most of the data processing responsibility from a centralized server to the field devices, thereby making the system more scalable for widespread deployment and relieving communications and centralized storage burdens. Several photographs show the hardware platform used for the pilot demonstrations:

- Figure 4-1 shows the front panel of two substation-based Feeder Monitors installed in a 19” rack. The hardware is packaged such that two Feeder Monitors can be installed side-by-side in a single 19”-wide tray, for installations with limited rack space.
- Figure 4-2 shows the rear panel of one of the Feeder Monitors, which shows the terminal-strip connections for conventional current and potential transformers. It also shows connectors for DC power; Ethernet; an optional weather-station; and sample synchronization.
- Figure 4-3 shows a Feeder Monitor packaged in an open-frame, dual-plate configuration. This alternative packaging requires an external housing, such as a NEMA-style enclosure. It was done for distributed, pole-mount pilot locations. A chief concern in such installations is thermal survivability of the electronics. The open-frame packaging provides better air flow and cooling than does the fully enclosed, rack-mount packaging shown in Figure 4-1. Neither package has had rigorous thermal testing or any specific thermal rating. However, limited comparative testing has confirmed that the open-frame, dual-plate package provides lower internal temperatures for the electronics than does the rack-mount package. There are connectors on the top plate for conventional CT and PT inputs; 12VDC power; and Ethernet. Because pole-mount Feeder Monitors will not generally be installed with weather stations or in the vicinity of other Feeder Monitors, the dual-plate packaging does not provide connections for a weather station or sample synchronization.
- Figure 4-4 shows a pole-mount installation, with a dual-plate Feeder Monitor installed in a NEMA-style enclosure near the bottom of a pole. The enclosure also houses ancillary equipment, such as CT and PT isolation switches, a radio, an AC-to-DC converter, and a battery. Conventional CTs and PTs are shown near the top of the pole. A radio antenna also is mounted near the top of the pole, to provide Internet service for the Feeder Monitor. The dual-plate monitor is circled near the top of the enclosure shown in the right-hand photograph.

Figure 4-1
Photograph of Substation-Based Feeder Monitors Installed for Pilot Demonstration

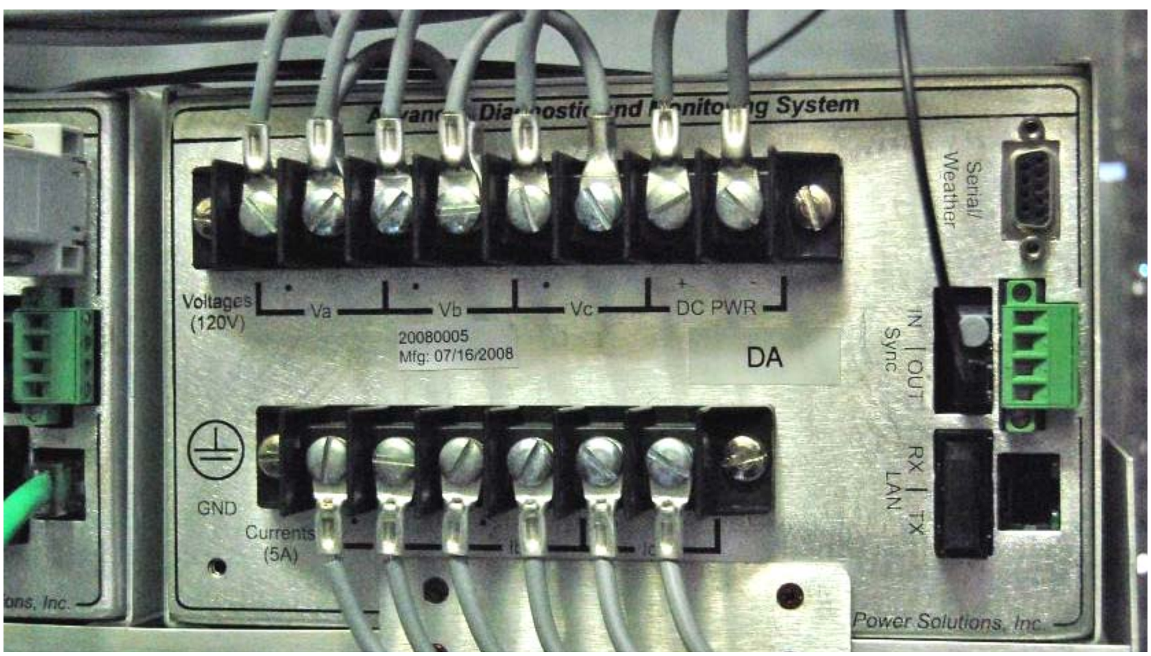


Figure 4-2
Photograph of Rear Panel of Substation-Based Feeder Monitor

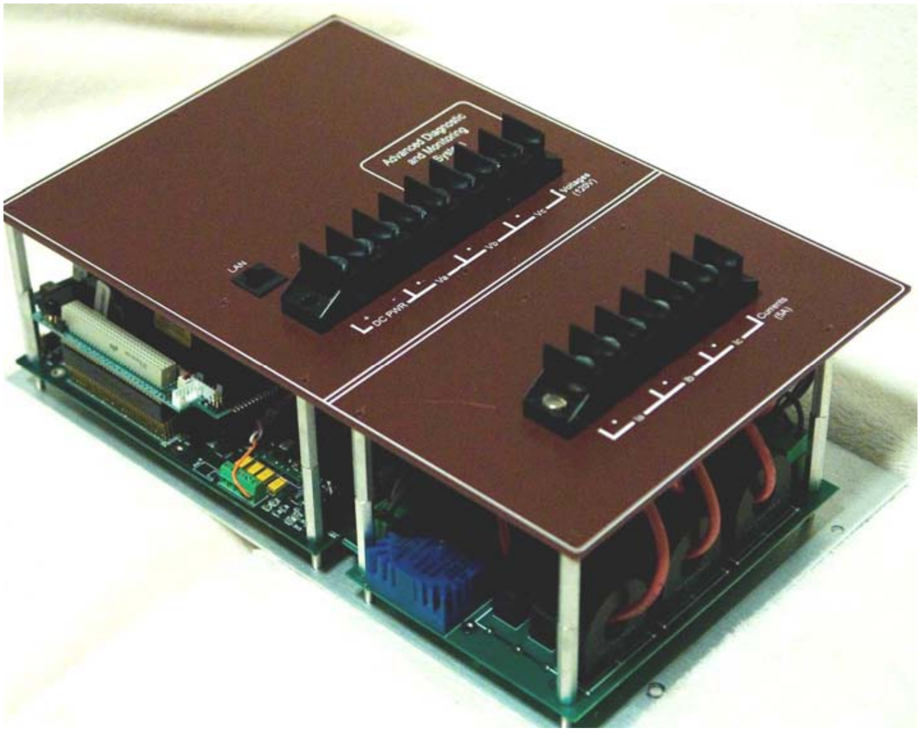


Figure 4-3
Photograph of Feeder Monitor in Open-Frame, Dual-Plate Package

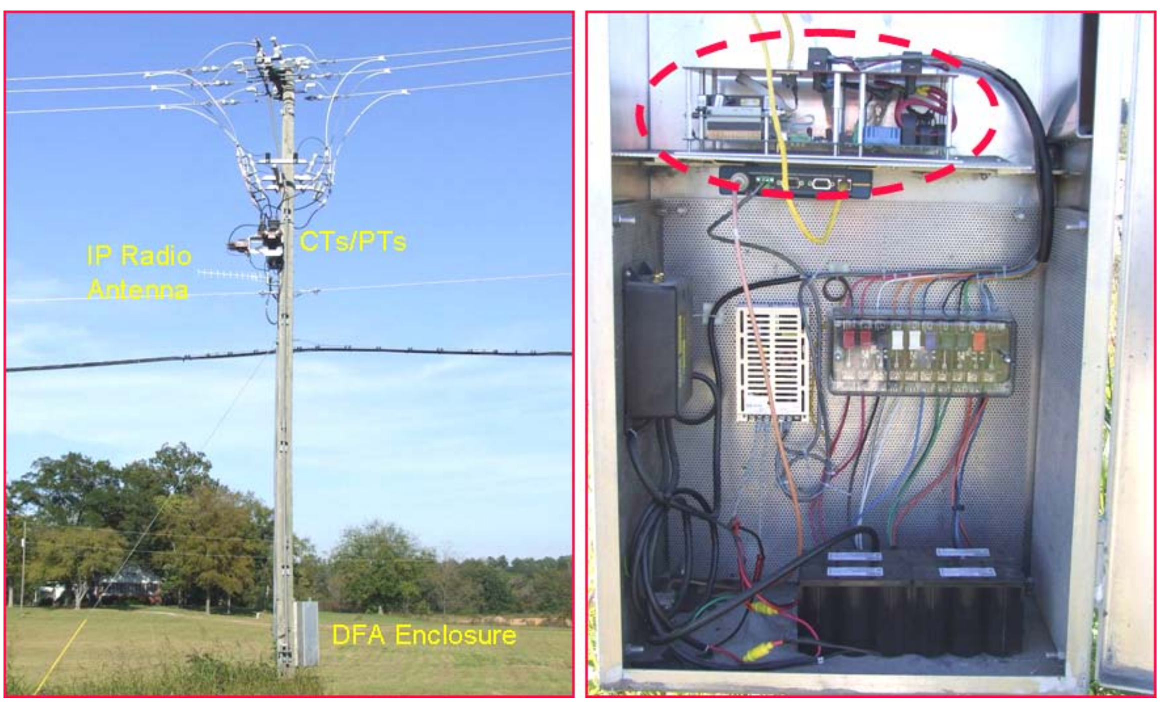


Figure 4-4
Photographs of Pole-Mount Enclosure (left) and Dual-Plate Monitor in Enclosure (right)

This effort involves interaction with utility personnel responsible for engineering, operations, dispatch, and maintenance. The intent is to make the technology useful in daily operations. Diverse "stakeholders" have diverse uses for data and information made available by the DFA. Issues are being addressed concerning how to make the right information available, to the right people, in the right form, in the right timeframe. This present report contains case studies about transformer failures, cable failures, and recurrent faults that illustrate specific examples of information capable of enhancing reliability, but the information must be targeted to the right groups within a utility, in the right form and in the right timeframe, to make it useful in real operations.

Texas A&M University leads this effort. Southern Company and Oncor Electric Delivery have been the primary utility partners, serving as initial demonstration sites. Oncor formed and led a focus group that provided early project guidance. This group identified multiple stakeholders and began the process of mapping which stakeholders need access to which types of information from DFA systems.

The DOE-funded pilot demonstration project and the EPRI-funded efforts have been highly complementary to one another. The EPRI project has provided conceptual guidance on system requirements and also continued to grow and refine the library of documented failure signatures, while the DOE effort adapted the hardware and software system to make it capable of implementing and exercising system concepts and algorithms and determining how to make results available and useful to end users in day-to-day operations.

Distributed Application

All initial DFA efforts were directed toward acquiring and processing signals and other information at the whole-feeder level. These efforts have documented measurements related to failures and failure precursors of apparatus on the feeder and all measurements have been from substation-based CTs and PTs.

There are multiple potential benefits to applying DFA technology on a distributed basis, using a topology similar to the one illustrated in Figure 4-5.

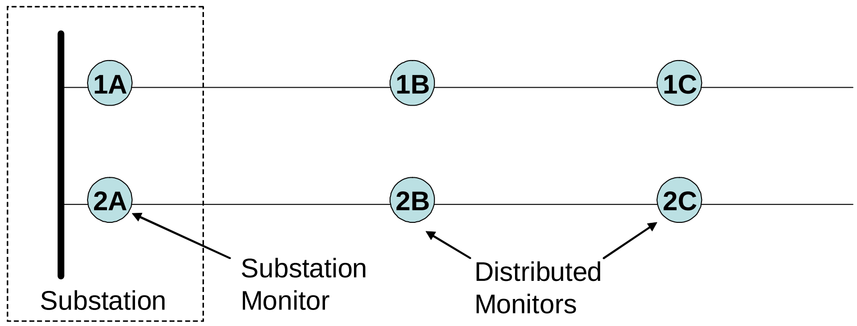


Figure 4-5
Distributed Application of DFA Monitoring

The most obvious potential benefits are in the areas of sensitivity and location. By definition substation-based devices measure total feeder current, which combines normal loads, transients, etc. with anomalous signals of interest. Measurements at points downstream of the substation also contain the signals of interest for those anomalies that are downstream of those points, but they contain less of the normal load signal. For instance a failing transformer near the far end of feeder 2 in Figure 4-5 will be seen in currents measured at points 2A, 2B, and 2C, but measurements at points 2A and 2B will contain more load current than the measurement at point 2C. Because failure precursors may be very subtle, lesser amounts of load current may make detection and characterization more reliable.

It also seems likely that distributed application of DFA technology could help better estimate the location of faults, failures, and failure precursors. A case study presented earlier in this report involved precursors to a failure involving an internal transformer winding (see *Case Study #9: Precursors Related to Internal Transformer Winding Failure*, page 3-21). Knowing about these precursors would have helped repair crews better diagnose the problem after the first outage occurred. Before the initial outage, however, if one simply knows that a transformer on a particular phase of a particular feeder is beginning to fail, it can be quite challenging to find which of the numerous transformers on the same phase of the same feeder is the culprit.

Techniques such as thermal and radio-frequency (RF) surveys can pinpoint some types of incipient failures. However, application of these techniques to situations like the aforementioned incipient, internal transformer failure is hampered by the fact that failure precursors tend to be intermittent. In that example, numerous individual precursors were recorded, but there also were long periods of time during which no precursors were recorded. RF scans may fail to identify the failing transformer unless it happened to be scanned at the precise moment of precursor activity. Periods of active precursors constituted a small fraction of the total time during that one-week period, calling into question whether RF scanning would have identified it. Further the magnitude of the precursors was limited to a few amperes. In some cases this might be enough to raise the temperature of a small service transformer sufficiently to be detected with thermal imaging. Temperature rise is a function of instantaneous power integrated over time, so the temperature rise will be significant only if the activity persists for a substantial period of time.

Precursors in this and many other cases, however, consist of a limited number of small-magnitude bursts, each a few cycles in duration. This would not be likely to raise the temperature noticeably, certainly not enough to differentiate the temperature of the subject transformer from other transformers with different levels of normal, long-term load.

Distributed application of DFA technology may provide better information about the location of these and other types of failures and incipient failures. A failing transformer at the remote end of feeder 2 in Figure 4-5 should produce signals measurable at points 2A, 2B, and 2C. This could allow the search area to be narrowed to that section of the feeder that is downstream of point 2C. By contrast, a failing transformer located between points 2B and 2C should produce signals measurable at 2A and 2B, but not at 2C, allowing the search to begin between 2A and 2B.

The initial distributed effort has instrumented a total of four distributed points on two feeders coming from one substation. This effort is scientifically significant, because it is the first-ever collection and analysis of distributed data with this sensitivity and fidelity. However, a larger number of more diverse sites clearly would be more desirable. Multiple utility companies have expressed interest in hosting pilot demonstration sites, and some of these are considering instrumentation of distributed locations in addition to substations. At the writing of this report, potential projects are being defined with multiple utility companies.

Reliability Based Vegetation Management Project

Vegetation management is the largest single cost item in the maintenance budgets of many utility companies. Vegetation management typically is driven by calendar-based cycles. PSERC (Power Systems Engineering Research Center) funded a project at Texas A&M in an attempt to study and better understand the relationship between reliability and electrical measurements that indicate vegetation encroachment. As part of that project, researchers staged experiments in which they used tree limbs to bridge the normal separation between a phase conductor and a neutral conductor on a 12.47/7.2-kV primary distribution system. They used high-fidelity instrumentation to record measurements from the substation serving the test facility.

These experiments created a better understanding of the electrical behavior that occurs when a tree limb bridges two primary conductors. In short these experiments found that:

- A tree limb making contact with a single phase conductor is not likely to produce high levels of fault current, because the current must pass through contact impedance and the significant impedance of the tree’s limb, trunk, and root structure to find a return path through the earth. This scenario produced only a few amperes of fault current during experimentation. There was considerable heat generated at the point where the tree contacted the primary conductor, however, which may lead to fire or weakening of the conductor, thus causing faults, outages, and safety hazards.
- A tree limb bridging two primary conductors produces an interesting sequence of events that can produce momentary interruptions, sustained outages, conductor damage, and burning vegetation. Initial contact typically does not produce significant current immediately, but scintillation does begin almost immediately at each point where the limb contacts the

conductors. This produces localized heating, which begins to burn and char the surface of the limb. The charred portion of the limb becomes conductive, but the portion of the limb that is not charred continues to limit fault current to a low level. The process evolves, with the surface of the portion of the limb immediately adjacent to the already charred portion beginning to scintillate and thereby becoming charred itself (see Figure 4-6). The charring process occurs preferentially in the direction toward the limb's contact point with the other conductor. As the charred path from each end point grows longer, the length of limb that is not yet charred becomes progressively shorter. Over a period of several minutes, if no mechanical movement of the limb or conductors disturbs the process, the charred paths from the two points will meet somewhere in the middle of the portion of the limb between the conductors. This provides a continuous path of relatively low impedance and the level of current rises precipitously. The larger current may cause operation of an overcurrent device (e.g., fuse, recloser). In many cases this does not happen, however. Instead the fault current begins flowing in the low-impedance path created by the burning plasma along the surface of the limb (see Figure 4-7). The heat of the plasma causes it to rise. Much of the fault current follows this preferential low-impedance path as it rises and elongates, thereby exhibiting the well known Jacob's Ladder phenomenon shown in Figure 4-8. When the arc becomes too long to be sustained by the available voltage, it extinguishes. The char and burning plasma along the surface of the limb enable quick formation of a new arc and the process repeats. The process repeats until 1) system protection locks out, 2) the limb burns in two, 3) mechanical movement causes loss of intimate contact between the limb and one or both conductors, or 4) the limb burns off and causes loss of contact. If system protection trips but then recloses before the conductors or limb move, the charred, burning surface readily initiates a follow-on fault. However even slight movement can cause delays between bursts of fault current, as new paths must char before producing high-amplitude fault currents. Depending on fault geometry, the time for this to happen can exceed the reset time of reclosing logic, allowing a vegetation contact to cause multiple high-current events over a long period of time, without tripping protection to lockout. A DFA prototype previously recorded this exact scenario, in which a tree limb that spanned between primary phase and neutral conductors caused 17 recloser operations over a 24-hour period, ultimately burning down a line and causing an outage to 140 customers.

The PSERC vegetation project was hampered by the fact that utilities with installed DFA prototypes follow relatively conservative tree-trimming cycles, which has limited the number of data captures associated with vegetation contact. Experimentation efforts and ongoing monitoring have documented some cases of vegetation contacts and provide some insight into the electrical behavior caused by vegetation. Researchers continue to document such data captures when they occur and can be documented.

Figure 4-6
Carbonization, or "Char," Created when Vegetation Bridges Conductors

Figure 4-7
Arcing and Burning of Tree Limb Bridging Two Conductors

Figure 4-8
Arcing Rising with Hot Plasma and Forming Jacob's Ladder

Summary

In summary, the project that is the subject of this report has significantly advanced DFA technology. This effort is being supplemented and supported by other projects that address ancillary topics that are important, but that are beyond the scope of the fundamental EPRI project. This chapter has provided an overview of some of those activities, to give the reader a high-level perspective on the status of the technology.

5
COMMERCIALIZATION STRATEGY AND STATUS

Intellectual Property and Commercial Licensing

Through all phases of the Distribution Fault Anticipation (DFA) project, a key requirement has been to focus on and develop technological solutions that can be commercialized and put to practical use by utility companies. A further requirement has been the development of a commercialization strategy that considers the features of the technology, the ultimate users of the technology, and potential manufacturers of this type of technology.

EPRI-funded DFA research has resulted in the development of significant intellectual property (IP). Texas A&M filed eleven confidential IP disclosures with EPRI. Five patent applications have been filed and are pending with the United State Patent and Trademark Office, and additional patent applications are being prepared for filing. It would not be appropriate to detail those disclosures in a published report. However, it is anticipated that multiple patents will be granted to protect the IP. In addition to patentable IP, there is significant know-how that is more difficult to quantify, and which takes the form of confidential trade secrets. EPRI has exclusive commercial licensing rights to the patentable IP and the know-how.

The following subsections outline user requirements, the manufacturing landscape, and the commercialization model that was developed. This model was presented to and discussed with DFA Users Group members and members of EPRI's Distribution Council on multiple occasions and was included in the 2005 final report for the Phase II project. The model and the rationale are reproduced here for the reader's convenience, followed by comments on the current licensing status.

Utility User Requirements for Commercial Products

From the beginning of the project, the focus has been on discovering and developing techniques that will benefit utility companies by enhancing reliability, reducing operating costs, or both. Participating utility companies have consistently expressed their desire to see this technology made available in ways that will provide practical benefit to them.

Based on the stated desires and direction of EPRI and its member utilities, and based on the research team's prior experience in commercializing EPRI/Texas A&M technology, several guidelines emerged for the commercialization of fault anticipation technology. The following list gives these guidelines, along with comments about how the commercialization process can meet them.

- The technology should provide the user with useful information, not just data. Modern electronic devices (e.g., relays, power quality monitors) collect waveforms and other data from power systems. The data generally contains useful information, but utilities often cannot take full advantage of it, because they do not have the manpower to process the mountain of data that the devices collect. DFA technology should provide useful information in a way that helps the user understand and deal with problems.
- The technology should be available in a variety of platforms. Ideally, the technology should be integrated with a variety of existing and future electronic devices, such as relays, meters, etc. Some DFA functionality requires high-quality, high-capacity data flows. The quality and capacity are readily realizable in modern electronic design, but certain devices (e.g., relays) may not incorporate this level of capability, if the primary functions of those devices do not require it. Therefore, individual devices must be evaluated to determine their ability to support DFA technology, or some subset of the technology.
- The technology should be available from multiple manufacturers. Otherwise, a utility that does not use equipment from a given manufacturer can be "locked out" of the market if that manufacturer has exclusive access to the technology.

Traditional Commercialization Models

Texas A&M evaluated requirements and other input from EPRI and member utility companies to determine the most effective way to meet these objectives in the commercialization of the DFA technology. To this end, they evaluated traditional commercialization models to determine their applicability and their likely effectiveness.

A traditional licensing agreement is conceptually quite simple. The licensor, in this case EPRI, grants a manufacturer the right to use and sell a technology. The manufacturer develops and produces a product or a line of products and markets and sells these products to third parties, typically end users of the technology. In return, the manufacturer pays royalties to the licensor in amounts established by the license agreement.

In this type of agreement, the licensor can grant a manufacturer an exclusive license or a non exclusive license. If the license is exclusive, then the licensor cannot grant licenses to other manufacturers.

Variations are possible. For example, a license can grant a particular manufacturer the exclusive right to make and sell products using the technology in a niche area (e.g., standalone devices or embedded in relays). A license to practice in a niche area can be exclusive or non exclusive in that area, while permitting the granting of exclusive or non exclusive licenses to third parties in other niche areas.

Several problems with traditional approaches make it unlikely that they would succeed in the commercialization of DFA technology:

- An exclusive license limits access to the technology and limits future advancements of the technology. DFA technology incorporated into a specific manufacturer's product line means that every utility would be required to adopt that manufacturer's products in order to have DFA access. Utility participants have stated their strong aversion to such an arrangement.
- Traditional manufacturers are unlikely to invest the significant capital that will be needed to develop the technology into a product line, unless they can obtain exclusivity, at least for a considerable period of time.
- DFA technology has demonstrated that it can provide significant benefit to utility companies, but the technology currently uses research-grade algorithms in research-grade hardware. In addition, the DFA has not yet demonstrated its market viability. It will take significant effort and expense to fully develop the commercial product line and to develop a viable market. Traditional manufacturers tend to be averse to the risk associated with bridging the gap between laboratory and marketplace, particularly if they do not have the benefits associated with an exclusive license.
- DFA technology has developed significant capabilities that are ready for commercialization. However, EPRI, Texas A&M, and utility participants recognize that significant additional benefits remain to be discovered and realized from this revolutionary technology. Past experience with the commercialization of new technologies suggests that advances cease and development stagnates in the hands of a traditional manufacturer, particularly if that manufacturer has exclusive access to the technology.
- This project has produced considerable new knowledge and know-how. Algorithms and other discovered intellectual property are being patented, and a licensee will have the right to practice the technology covered by resulting patents. However, the project also has produced knowledge and know-how that are not readily reduced to writing or patentable form. In industry, this would be known as unpatented trade secrets. Access to the patents that are expected to issue will be necessary to practice the technology, but it will not be sufficient to practice the technology successfully. Also, past experience in the commercialization of EPRI technology suggests that traditional manufacturers may not develop the high level of internal expertise necessary to fully implement, support, and advance the technology. Therefore, the commercialization plan needs to provide for keeping this expertise base intact and ready, even after the initial technology transfer to the first manufacturer(s), so that it is possible to transfer the technology to additional manufacturing partners in the years ahead. Traditional commercialization plans do not provide for this flexibility.

DFA Commercialization Plan

It is clear that there are difficulties associated with using a traditional commercialization path for DFA technology. Therefore, a non traditional plan has been developed and is being pursued. Figure 5-1 illustrates this model.

A focused entity will be responsible for commercializing DFA technology. The key word here is "focused." The commercialization entity will have a team that is focused on advancing DFA technology in the commercial domain. Commercialization of DFA technology will not just be one of many tasks for this team, but instead will be the team's central focus. It is the intent of this entity to bring this technology to the market in two distinct ways that are meant to address the previously outlined user requirements and concerns.

- The commercializing entity will develop and produce systems for practicing DFA technology. The technology likely will be provided in a standalone system that provides DFA functionality and other related functions that are natural to provide in a platform with the DFA's capability. Royalties will flow back to EPRI based upon sales.
- In addition, the commercializing entity will be responsible for maintaining the expertise and know-how necessary for practicing DFA technology. It will provide sublicenses to third-party manufacturers that wish to integrate DFA technology into existing product lines or to develop new product lines around the technology. It also will provide these third parties with the know-how needed to successfully develop products and take advantage of the technology.

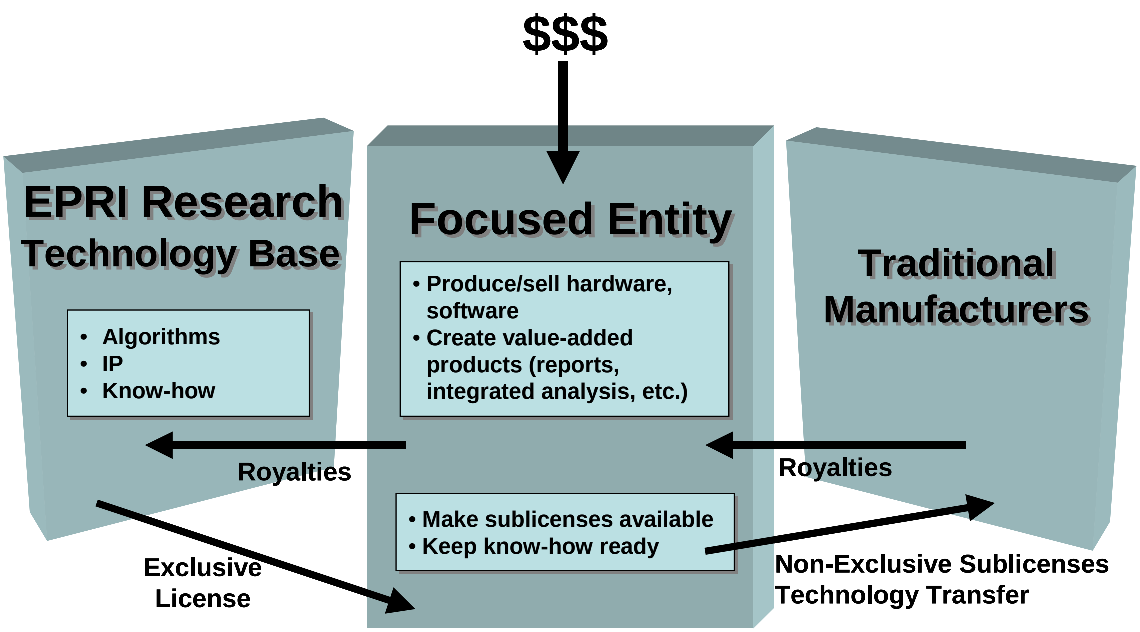


Figure 5-1
Commercialization Model for DFA Technology

Intent of Exclusive License

Figure 5-1 shows an exclusive license from EPRI to the focused commercialization entity. An exclusive license usually implies that only one manufacturer will supply the technology to end users. That is not the intent here. Rather, while the commercializing entity will have an exclusive license from EPRI, that license will carry with it a requirement that the entity make sublicenses available to third parties. The commercializing entity also will maintain the necessary expertise and know-how for practicing the technology, and provide this to third-party sublicensees to develop and provide DFA technology as part of their product lines. In short, it is not intended that the commercializing entity be the exclusive provider of the technology to end users. Rather, the commercializing entity will keep the necessary skills, know-how, and expertise intact and make them available to multiple third parties, as previously outlined. Both the license and the expertise will reside with this commercialization entity, which will in turn make them available to third-party manufacturers.

Commercialization Status

The preceding sections provide a review of the commercialization plan that was discussed with EPRI members during 2004-2005 and that was published in the 2005 report. With this model as a guide, EPRI negotiated a license with Power Solutions, Inc. to serve as the focused entity for commercializing DFA technology. These negotiations were successful and resulted in a license being issued to Power Solutions in 2006.

Power Solutions (PSI) has available to it key members of the research team and its leadership. Maintaining this expertise is critical to the successful development and commercialization of an advanced technology like Distribution Fault Anticipation, which by its nature is a knowledge-intensive technology. It also is apparent that DFA concepts have more potential than has been discovered and exploited to date. PSI is uniquely qualified to support the technology, perform technology transfer to third-party manufacturers, and continue improving the technology in the future. Of historical note, PSI holds the license to technology for detecting high-impedance, arcing faults on distribution systems, which also is a technology that was developed at Texas A&M with EPRI funding and support. PSI was successful in transferring that technology to a major manufacturer, which markets the technology to the utility industry.

Power Solutions makes DFA technology available in a custom platform. This platform is in use in pilot demonstrations at multiple utility companies, and other utility companies are considering pilot projects that will use this custom platform.

Power Solutions also currently is in discussions with multiple third-party manufacturers about how those manufacturers might incorporate DFA technology in their product lines. Utilities are encouraged to discuss with their vendors of choice the addition of DFA technology to their product lines as well. More is said in Chapter 6, *Areas for Further Research*, regarding opportunities to work collaboratively with utility companies and manufacturers to implement and deploy DFA technology commercially.

6 AREAS FOR FURTHER RESEARCH

Distribution Fault Anticipation (DFA) technology can detect and recognize incipient apparatus failures (e.g., failing switches) and improper feeder device function (e.g., capacitor bank controller operating too often). It also can provide greater general situational awareness, by automatically analyzing data to characterize conventional faults, based strictly on waveforms from conventional CTs and PTs. This includes recognition and characterization of operations of distributed sectionalizing devices such as reclosers, without the need for communications with those distributed devices. Recent DFA efforts are demonstrating the type of web-based reporting that is suitable for use by utility dispatchers, reliability engineers, capacitor maintenance crews, etc. However there are several obvious areas in which future research could enhance the technology.

Fault Location

When DFA research was first undertaken, it was the conscious, consensus decision of EPRI and EPRI-member utility companies to first concentrate on demonstrating that incipient faults could be detected and recognized, deferring considerations about their location until later. That time has now come.

The DFA platform provides the necessary data structures and fidelity to implement conventional fault location techniques. Impedance-based methods exist for locating faults on transmission systems. Underlying these methods is a fundamental assumption that line impedance is the primary factor determining fault magnitude. Measured fault currents and voltages are used to calculate impedance, which can then provide a location estimate. These techniques have been adapted for use on distribution systems, and are used with some success for locating high-current, "bolted" faults. However, distribution circuit topologies are more complex than transmission circuits, making precise location more difficult.

Locating incipient faults is considerably more challenging than locating high-current faults. Line impedances and other power system parameters only weakly influence the level of current produced by subtle, low-current, arcing failure precursors. Local arc-gap and contact impedances are primary determinants. For example, when a tree limb contacts a line at a point on a circuit where the available fault current is 5,000 amps, contact impedances may limit current to only 20 amps. Furthermore the 20-amp fault may be time-varying and intermittent in nature, producing current only when the wind blows a particular direction. System and line impedance to this location may be one the order of one ohm, but the impedance of the tree and any associated arc gap may be hundreds of ohms. Furthermore, these impedances are unpredictable and time-varying. Therefore, using the measured 20-amp current for a conventional impedance calculation has little value. Other methods must be explored.

There are multiple categories of potential methods that can be examined for their potential relevance and efficacy for locating subtle distribution failures. DFA efforts to date have been constrained primarily to substation-only measurements of electrical signals. Current work involves a small number of distributed, pole-mount DFA monitoring points that will allow some assessment of additional value and limitations from such measurements.

Electrical measurements could also be coordinated with other methods, such as RF (radio frequency) detection, thermal imaging, etc. Other potential approaches include the use of temporarily or permanently installed faulted circuit indicators (FCIs). FCIs currently available on the market are intended for high-current events that cause permanent outages, and likely are not directly suitable for locating incipient faults. However, some of the underlying technologies currently employed (clamp-on sensing, wireless interrogation, etc.) may be adaptable and provide benefits. Integration with utility GIS/mapping systems may also provide benefits for locating incipient faults, because circuit topology affects interpretation of electrical measurements.

EPRI currently has research efforts underway with regard to locating conventional faults on distribution systems. Methods outlined herein for incipient-fault location may serendipitously result in methods beneficial to locating conventional, high-current faults as well, although their primary intent is not location of high-current faults.

There are multiple candidate technologies and categories of technologies that may have merit for the location of low-current, incipient faults. Much depends on the constraints imposed: substation-only measurements versus substation-distributed hybrid; electrical signals only versus other types of inputs; GIS/mapping or not; the list goes on. The process naturally falls into three phases:

1. Research, enumerate, and describe potential methods for incipient fault location.
2. Determine constraints to be imposed and select candidate methods for detailed study.
3. Perform detailed research, analysis, and testing on methods so chosen.

The first phase would culminate with a report enumerating and describing potential methods. The second phase should include significant input and direction from EPRI member utilities, probably in the form of a meeting to review candidate technologies with industry advisors and receive their input. The scope of the third phase would be determined based on the outcome of the first and second phases.

Integration with Specific Manufacturers' Product Lines

EPRI and EPRI-member utility advisors have been consistent and clear on their desire for DFA technology to be made available from multiple vendors. The commercialization structure previously outlined was conceived with that goal in mind (see Chapter 5, *Commercialization Strategy and Status*). This report has outlined key factors that must be analyzed when considering the implementation of DFA technology in any particular platform (see Chapter 2, *System Integration Considerations*). Greater specificity in each area requires consideration of specific manufacturers' platforms, which was beyond the scope of the current project.

Manufacturers have largely taken a "wait and see" approach to the adoption of new, advanced technologies like DFA. They are hesitant to commit the resources necessary to implement, market, sell, and support a new technology, when they have not yet sensed clear direction from their customer base, regarding future purchases of the technology. Conversely, many of their customers, which are largely utility companies, desire to see product offerings demonstrated before committing to large-scale purchase and deployment.

This "chicken and egg" problem is not unique to DFA technology, but it is nevertheless a significant hurdle. A possible approach would be a multi-party collaboration, involving one or more utility companies and a preferred manufacturer of those utilities. Such an approach may require pooling funds from multiple parties, including the manufacturer and the participating utility companies. It should be noted that there could be multiple, parallel efforts, each involving a particular manufacturer and one or more utility companies. It is believed that such an undertaking would entail steps similar to the following:

1. Determine utility companies willing to guide and provide funding, and identify a manufacturer acceptable (ideally, preferred) to those companies.

2. Determine selected manufacturer's fundamental position on adding new technologies to existing and new product lines.

3. Work with manufacturer and utilities to determine feasibility, constraints, limitations, etc. for implementation in one or more of manufacturer's products or product lines.

4. Estimate level of effort and projected pricing structure for final product line and review with participating utility companies.

5. Determine appropriate funding structure and participants.

6. Proceed collaboratively with manufacturer and utility companies, to perform technology transfer, implementation, deployment, and testing.

It is implied that the research team needs to be intimately involved in each step.

Adaptation of Technology to Transmission Application

Research to date has focused on medium-voltage distribution systems. However, the automated concepts and architectures devised to perform the acquisition, handling, analysis, and presentation of large quantities of data, without human intervention, should be generically applicable to multiple levels of the power system. Specific types of failures, failure processes, and thus the resulting failure signatures, would be expected to be different on transmission systems than those seen on distribution systems, but the generic, systemic processes should remain the same or similar. Multiple utility companies have expressed interest in participating in a research project to investigate application and adaptation of DFA technology to transmission systems. A project would include steps similar to the following:

1. Select multiple transmission circuits for medium-term (i.e., two years, at a minimum) monitoring. This amount of time is believed necessary, because failure events are relatively rare on transmission circuits – although they have significant impact when they occur. The likelihood of experiencing a meaningful number of naturally occurring failures is roughly proportional to the number of circuits monitored, and the length of time monitored.
2. Use system concepts and the hardware/software platforms developed for the distribution project, to collect data from these circuits.
3. Record failures, failure precursors, and other anomalies as they occur naturally.
4. Carefully investigate and document failures, and waveform signatures before and during the failures, to determine causal relationships.
5. Evaluate where existing system concepts are suitable and where they may require adaptation.

This plan is similar to the early days of the distribution project, in that the types of failures, failure precursors, and electrical signatures have never before been investigated with this level of sensitivity and fidelity, and therefore their subtle characteristics are unknown. However, this project will have the advantage of building on the system developments and the experience gained in the distribution project.

Continued Advancement of DFA Technology

DFA technology has significantly advanced the state of the art in automated data capture, retrieval, management, analysis, and presentation. However, significant fundamental potential remains to be tapped. For example, there were multiple occasions during the DFA research in which the cause of measured anomalies was not determined. This was largely a result of the fact that neither the research team nor participating utility engineers had ever seen some of the anomalies, and therefore had little guidance on how to begin determining their cause. As additional systems are deployed, and particularly as they are deployed as an operational tool, rather than a research project, more utility dispatch, engineering, and maintenance personnel will have direct access. It is believed that such day-to-day use will lead to discovery of the relationship between anomalies and their underlying power system events. As those relationships are discovered, additional algorithm development and testing will be necessary.

The real-time and historical database created to support DFA functionality contains much information useful for other purposes. For example, statistics about basic power system quantities (e.g., amps, volts, watts, VARs) are computed and stored for each feeder at regular intervals (e.g., 15 minutes). This information can be useful for planning purposes, but the analysis, interpretation, and presentation processes need to be highly automated, to avoid manpower-intensive processes that simply do not get done because of a lack of time. There are multiple other examples of valuable functions made possible by the database and highly automated processes underpinning DFA technology.

Texas A&M University has established a DFA Technology Consortium, with memberships available to utilities and manufacturers. The principal researchers who have been responsible for the research to date use this consortium to continue advancing DFA technology and exploring and exploiting additional benefits. The consortium allows utility and manufacturer members to stay abreast of DFA technology advances and to influence future direction.

7 SUMMARY

EPRI-funded research at Texas A&M University has demonstrated the ability to use sensitive monitoring to improve distribution system operations and reliability. Field installations have characterized failures and precursors to failures. The presence of intelligent monitoring systems also has proven to be an enabling technology for a wide variety of other functions, beyond the initial focus of the project. Such systems enable the implementation of operations and maintenance tools to increase reliability, solve "mystery" problems, increase the efficiency and effectiveness of certain maintenance practices, and generally improve situational awareness.

Project efforts resulted in prototype equipment being installed to monitor 60 feeders in 14 EPRI-member substations across North America. The majority of these installations remain functional, and researchers continue to use them to collect data on failures, incipient failures, and normal and abnormal system operations. This enables new knowledge and understanding about equipment failure processes and their precursors, and suggests new functionality for the DFA platform.

Prototype monitoring systems were designed to facilitate research objectives and therefore used highly centralized approaches for data collection, analysis, characterization, and management. These prototype devices were appropriate research tools, but were not intended to support widespread deployment by utility companies or integration into their operational and business practices. The current System Integration project has defined multiple, interrelated issues and constraints related to making Distribution Fault Anticipation technology useful in widespread, practical application.

A fundamental conclusion of this effort is that large-scale data collection efforts can realize maximum value only with highly automated processes that require minimal human intervention and interpretation, rather than manpower-intensive data management, analysis, and interpretation processes. Another fundamental conclusion is that it is desirable to perform the maximum possible amount of processing and "intelligence" at the individual device level, passing only highly processed results to a central master station for aggregation and presentation to end users.

Complementary projects have occurred concurrently with EPRI-supported DFA work. Pilot installations that began as part of a DOE-funded effort are testing and demonstrating integration of DFA technology in utility business and work practices. An effort funded by the Power System Engineering Research Center (PSERC) will perform comparative characterization of non conventional voltage sensors, to determine whether sensors with lower installed costs can meet requirements for DFA and other advanced technologies.

EPRI has licensed the DFA technology to Power Solutions, Inc. (PSI) for commercialization. PSI has available to it individuals who have had significant involvement in the research and development, and that therefore have intimate familiarity with the technology. The license provides for PSI to market DFA technology directly and to grant sublicenses to third-party manufacturers. The intent is to make the technology widely available, by granting sublicenses to multiple manufacturers, so that, to the extent possible, utility companies can obtain DFA technology from their preferred providers, rather than being captive to a single manufacturer. PSI makes available a platform for practicing DFA. PSI also offers sublicenses and technology transfer services to third parties wishing to incorporate DFA technology in their product lines.

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