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Distribution Fault Anticipation

Phase III: System Integration

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ABSTRACT

Reliability and operational economics both 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 use of detecting changes in electrical signals to determine when faults and incipient faults are developing on distribution feeders, and to use this information to target maintenance where actually 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 equipment failure. Project researchers developed algorithms to characterize collected data and demonstrated the ability to use this data to diagnose many faults and fault precursors.

All previous work was done in a research setting, some facets of which are not practical for widespread deployment and day-to-day use by utility companies. The current System Integration project is developing system concepts that enable the technology to be transitioned from research project to practical application. In addition EPRI has licensed the technology for commercial development. There is significant synergistic benefit to having the conceptual system integration work being conducted in parallel with the licensee's preliminary development of commercial grade hardware and systems, with the two projects feeding and complementing each other.

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- BC Hydro
- Consolidated Edision
- CPS Energy
- Exelon
- Keyspan Energy
- MidAmerican Energy
- Northeast Utilities
- Southern Company/Alabama Power Company
- Tennessee Valley Authority/Pickwick Electric Cooperative
- TXU Electric Delivery

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PROJECT BACKGROUND

Rationale and Justification

The advent of 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 the utility provided 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.

In today's environment, utilities must offer service at the lowest possible cost if they are to attract and retain customers. At the same time, there are ever-increasing pressures for providing more reliable service. Traditional means to achieve high reliability include significant expenditures in the area of preventative maintenance of system components. By its 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 microcomputer 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 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 have 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 microcomputer-based digital monitoring 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 that problems were developing and thereby avoid failures and outages by taking preemptive action – with less reliance on inefficient, time-based, preventative maintenance programs.

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 premise that detectable electrical changes occur as line apparatus begin to fail. 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 by means of continuous monitoring that detected subtle changes in a variety of electrical parameters and recorded high-fidelity data when such changes occurred. Researchers periodically connected to the substation-based data collection equipment via dial-up modem to retrieve newly captured data. A member of the research team then examined each data capture 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 or knew that anything was developing. 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 quite 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. All 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

In 2000, Texas A&M undertook the second phase of the EPRI-funded fault anticipation project. This effort expanded the number of monitored feeders significantly, increased the number of utility companies directly involved, 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 greatly enhanced in comparison to the systems used in the initial phase. This redesigned 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. Each prototype was designed to monitor between two and eight feeders, depending on the desires of the participating utility company and the configuration of the selected substation. A total of sixty feeders were instrumented and monitored at the aforementioned fourteen substations, as illustrated in Figure 1-1.

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.

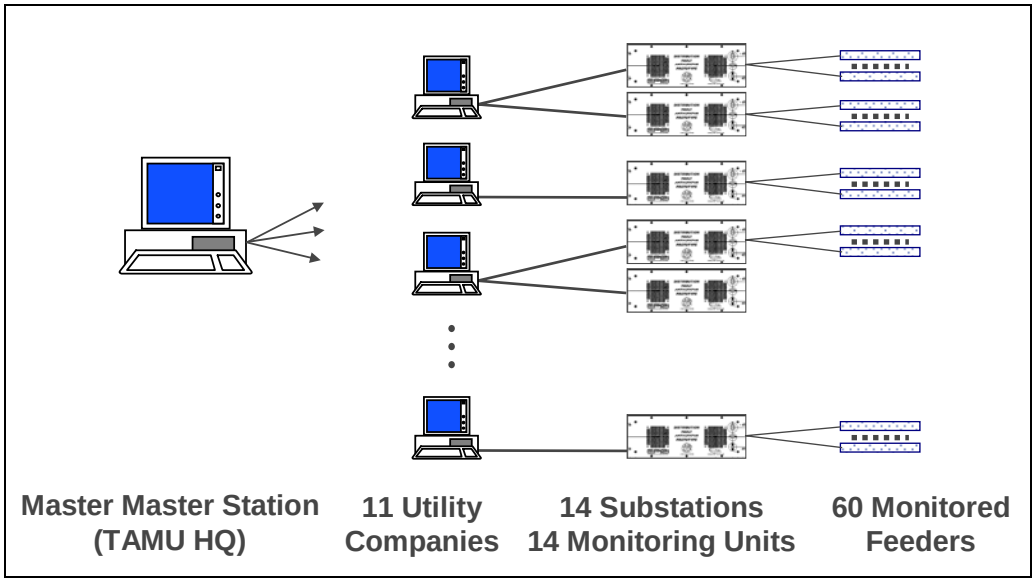

Figure 1-1
Network of Distribution Fault Anticipation (DFA) Prototypes

The system took advantage of the growing availability of high-speed Internet for data retrieval. It also created processes to automate the retrieval of data from the field equipment to master stations at each utility and a "Master Master" station at Texas A&M headquarters. This made data collection much more efficient and greatly reduced the level of manpower required for this function.

Participating utilities were more directly involved during the second phase as well. After installing prototype equipment in their substations, they had responsibility for investigating the cause of any interruption, outage or other abnormal occurrence on the monitored feeders. They also had responsibility for determining which data from their prototype was associated with these events. The utility companies needed direct access to the data to do this. Design of the prototype system therefore included master station software that allowed each utility to access the collected waveforms from its own prototype(s) and attach classification codes and other information related to those waveforms.

The expanded effort resulted in the acquisition of a large volume of data and the characterization of numerous normal and abnormal feeder events. When configuring data collection devices there is an inherent tradeoff involved – set triggers sensitively and capture a large amount of data, much of which is of little direct value or interest, or set triggers insensitively and miss some events that truly would have been of interest. 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 might manifest themselves electrically. A further consideration was that incipient faults do not occur with great frequency. Therefore 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 in terms of the types and levels of signals to be discovered, the data collection equipment was designed with considerable flexibility in its ability to be configured and initial default threshold settings were quite sensitive. The systems allowed remote reconfiguration to adjust sensitivity if 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 a large amount of normal system data would be captured and would have to be retrieved, processed, archived, etc.

As expected this data collection philosophy resulted in the capture of a very large number of events, the vast majority of which were normal system events such as capacitors switching, large motors starting, and the like. Project personnel developed considerable knowledge about the types and levels of signals that occur as various apparatus begin to deteriorate. They also became quite adept at analyzing captured waveforms and using these waveforms to recognize the underlying causal power system events. Utility engineers provided much-needed feedback to determine details about failures that occurred and the resulting captured data. 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.

A significant number of failure modes were documented during this phase of the project. During the current Phase III project, personnel have continued to take advantage of the now-installed network of prototype systems. Continued data collection and analysis help to refine classification methodologies. These efforts also continue to document additional types of failure modes and enhance the robustness of characterization and classification methods.

The Phase I and Phase II projects 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
- Repetitive 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
- Substation bus capacitor bushing failure
- Customer transformer bushing failure
- Capacitor problems
  - Controller failures (excess operations)
  - Failed capacitors
  - Blown fuses
  - Switch restrike
  - Switch sticking
  - Switch burnups
  - Switch bounce
  - VAR tolerance problems
  - Pack failure

Some types of failures were quite common and multiple instances were documented. As may be obvious from the list above, the most prevalent problems involved capacitor failures of one sort or another. Some types of failures are statistically less probable and less frequent than others. The project documented large numbers of certain types of failures but relatively few episodes of other types of failures. For some, there was only one example that occurred and was documented during the project.

Researchers developed methods for characterization and classification of many of the captured events. Clearly those failure modes with the greatest representation in the accumulated database provided the best opportunity to develop, test and refine classification methods, with events that occur less frequently providing more limited opportunity for this development. These methods continue to be evaluated and refined as additional time passes and new episodes occur on the monitored feeders.

Conclusions from Phase II Project

The large-scale data collection activity of Phase II of the Distribution Fault Anticipation (DFA) project demonstrated the ability to detect, characterize and recognize a wide variety 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 and classifying captured events. They created processes for running these algorithms on captured events 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 14 substations, the algorithms initially were developed in MatLab™ and were run on a computer server system at Texas A&M headquarters. This required all captured data to be retrieved from the substation devices to Texas A&M's server, via Internet connections to the substations. The volume of data was immense, but manageable for a research project monitoring 60 feeders. It would not be desirable to be forced to retrieve, store, archive, etc. such a volume 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 also meant an absolute requirement for high-speed data transfer (e.g., cable modem, DSL, and the like) to transfer this volume of data back to Texas A&M 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 and recognizing these signals and signatures. Some of the processes (e.g., archiving) were not fully automated and would be 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 is needed to develop the appropriate architectures and determine requirements for system integration. That work is the focus of the current project. In addition,

while the Phase II project 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 make it natural to continue learning from these in-place systems to further develop and refine characterization and classification algorithms. Therefore the current project focuses on development of concepts related to system integration to make DFA technology more practical and on continued data collection and algorithm development and refinement.

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SYSTEM INTEGRATION CONSIDERATIONS

Research efforts in pursuit of Distribution Fault Anticipation (DFA) technology have always had as their goal the development of concepts that can be put into practice to improve a utility's operations. Early phases of the research were directed toward validation of the concept of monitoring electrical signals for signs of degradation and imminent failures and toward developing techniques for recognizing subtle signs of failure and improper operation.

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 in utility substations and on feeders. The level of data acquisition, storage, processing and the like would have been impossible or at least cost prohibitive even ten years ago. Even with today's advances, careful attention must be devoted to providing sufficient digital capability to perform DFA functionality properly, without creating requirements that would make its practice cost prohibitive.

Current tasks are directed toward determining appropriate means for performing the DFA's basic tasks in ways that are practical for implementation in hardware and software systems for widespread deployment by utility companies. Because this work is in progress, the following discussion does not attempt to provide final details or solutions but rather a discussion of the chief considerations and constraints for such a system.

Important considerations conceptually fall into several broad categories, as discussed in the following. As will become clear to the reader, there is considerable overlap between these 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 circuit 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 specifications for the fidelity, rate, duration, etc. also are very different. Relaying applications, for example, generally require the ability to represent and recognize relatively high 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 absolute 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 circuit. 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.). Further a fault 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 have the ability to faithfully reproduce voltage and current waveforms and to do so 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 filter and otherwise condition signals 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 platforms 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 the resulting data would be able to discriminate a signals that was $20{,}000/2^{14}$ = 1.22 amperes. However the related electronics may introduce electromagnetic noise onto the signal path so that the A/D converter sees the real signal plus white noise at its input. Some signal-conditioning electronics can introduce white noise equivalent to several bits of the A/D converter's range, negatively impacting the effective 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 will be reduced from 14 to 11 and the effective ability to discriminate small changes in signals would become $20{,}000/2^{11}$ = 9.77 amperes. Signals and signal changes below this effective resolution are buried in electronic noise and are not useful for analysis. The cited resolution likely would be adequate for traditional applications such as relaying, but would not be sufficient for sensitive applications like the DFA. Parenthetically, it should be noted that digital signal processing techniques exist that can effectively recover bits lost to white noise but these work only on signals that are periodic and steady-state in nature. These techniques are not effective during transients or when signals are dynamically changing from one cycle to the next. It is during these dynamic periods that the DFA performs much of its function, making such techniques of little or no value to DFA applications.

Sampling rate is another key consideration with regard to data fidelity required for practicing DFA technology. As with most such considerations, there are tradeoffs involved. Every data sample must be acquired, moved, managed and processed by the processor. Applications like overcurrent relays are interested in fundamental frequency current and do not require high sample rates. Early digital relays used very limited sample rates, such as four samples per cycle. These devices were able to perform their protective function adequately with this limited sample

rate. Over time, sample rates have increased significantly, largely because of the recognition that sampled currents and voltages could be stored and used for other purposes. However many protective relay implementations still do not have adequate sample rates to provide for full practice of DFA technology, because of the relatively broadband signals that the DFA uses.

In summary there are multiple aspects related to data acquisition that directly affect the ability of a platform to support DFA technology properly and optimally. Requirements are being evaluated in terms of the various aspects discussed above.

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, determine whether protective devices operated correctly, and the like. Relays typically store several cycles of data per event and have the capability of storing multiple such events before exhausting their 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 most 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 actual physical contact only intermittently. During these contacts there may be sufficient electrical signal to be detected but when the limb mechanically moves away from the line (i.e., 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 long periods 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 commercial 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 longer 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 the vast majority of 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. The simplistic "FIFO" (first-in-first-out) approach of simply deleting events

and other data based solely on time results in "old" but important events being discarded while "new" episodes of routine system events are retained. Clearly this is not an optimal solution.

Requirements for these and other issues related to data storage and management are being studied and evaluated to determine appropriate approaches for performing DFA functions properly within commercial constraints and limitations.

Processing Architecture

DFA prototypes relied on all characterization and classification functions to be performed at a remote master station 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 the multiple field units each time such a change was made. One of the significant ramifications to this was that it required all data to be retrieved to Texas A&M's master station and it required the master station to perform all of the characterization 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 become 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 poletop recloser operation. The fault/trip/reclose sequence occurred again about an hour later when the limb again made contact. Then nothing further happened over the next sixteen hours. Following that the fault/trip/reclose cycle occurred 14 more times over the next few hours and finally resulted in the line burning down, causing a downed conductor situation and an outage for over 100 customers. The utility believes it could locate such a problem within a few hours of notification and thereby prevent the ultimate damage and outage, but to do so obviously requires notification as soon as possible after the activity begins. 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 is highly dependent on the communications 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 or the processing burden for a utility that fully deployed DFA technology 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 of the system hierarchy. Certain diagnoses can be made based upon individually captured events, while others require sequences of such events or information from events on other feeders (such as is the case when an event on one feeder causes sympathetic data captures on other feeders or when events upstream of the substation cause perturbations and event captures).

All of these aspects are being considered in the development of appropriate system architecture concepts for deployment of DFA technology.

Processing Burden

Another concern for any digital device that is responsible for real-time processing is the burden placed upon the processing assets. Clearly the processor must be able to meet the average processing burden, such as continually computing RMS values from samples, checking values against thresholds, and the like. For a truly continuous process, these functions must proceed without interruptions in the data stream or latency that would be significant enough to cause undesirable delays. In addition to this continuous, baseline processing, the processor and supporting systems must be able to characterize incoming data, without exceeding acceptable delays between the time an event occurs on the power system and the time at which information is brought to the attention of appropriate users. The amount of delay that is acceptable may be different depending on the type of event and the utility's planned response to that type of event. To use an example cited earlier in this report, 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 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 units, but all 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 fully deploy DFA technology on thousands of feeders, the processing burden soon would overwhelm a centralized system. Multiple centralized servers clearly could be used, but this still would not be an optimal solution because of the other issues, like transporting the voluminous data to the central location, requirements for high-speed communications at all locations, etc.

If all processing is not to be done at a centralized location, the most obvious location for it to occur is at the data collection device itself. Prototype systems had limited processing capabilities and the characterization algorithms were optimized for ease of implementation and evaluation, not for optimal processing. Issues related to distribution of processing responsibilities at various levels of the architecture are being considered and evaluated.

Communications

Prototype systems used for research required high-speed Internet to every field data-collection device. It is clear that making this a requirement going forward would limit the locations in which DFA technology could be deployed. The possibility and ramifications of applying the technology in distributed, pole-mount locations are receiving considerable discussion as well. Communications to these distributed locations generally will be more limited than in substations. Therefore one key to the deployment of DFA technology is to minimize its reliance on communications, particularly high-speed communications.

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 configuration required a utility to bring the CT and PT leads from all feeders that the DFA was to monitor to one 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 that had eight-feeder units generally having more difficulty than those with fewer feeders to monitor.

Some participants expressed their opinion that it would be quite difficult for them to deploy DFA technology on a widespread basis if they had to bring CT and PT wiring for a significant number of feeders to a central location. Therefore it is desirable to have the ability to distribute the sensing and data acquisition circuitry around the substation, so that CT and PT wiring lengths can be kept to a minimum. However doing this creates other technical challenges. For example it is relatively straightforward to synchronize the sampling of the data acquisition circuitry for multiple feeders when all of the feeder modules physically reside in a common chassis. This becomes less straightforward when the modules are distributed at multiple locations in the substation. While most DFA functionality does not strictly require absolute sample synchronization between the various feeder modules, it is necessary to maintain reasonable synchronization between the modules to best classify data captures that result when an event on one feeder causes sympathetic data captures on other feeders.

Sampling 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 unacceptable between dispersed modules 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 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 optic 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 and other devices. These existing platforms perform some of the same fundamental functions that are required for DFA technology. Each connects to power system sensors (e.g., CTs and PTs, or other sensors), conditions and digitizes electrical signals representative of currents and/or voltages on the power system, and performs some type of processing on these signals. Virtually all modern platforms also have the capacity to store current and/or voltage waveforms when the waveforms exhibit specific behavior, making these captured signals available to utility personnel for subsequent analysis.

It is obvious that integrating multiple functions in a single device would produce benefits as compared to having multiple, individual, single-function devices. There should be potential for savings in terms of the devices themselves. There also should be potential for considerable savings in terms of panel space and CT/PT wiring costs.

As previously outlined the DFA is able to detect subtle changes in electrical parameters and determine individual failure characteristics and trends. This places higher requirements on the system than most 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 modifications are needed to their existing designs to provide the foundation for practicing DFA technology in parallel with their existing functions. Ongoing work continues to assess these requirements.

Sensing

Current DFA prototypes receive their 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 these distributed points, there often will be no existing CTs and PTs and 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 current and voltage signals. Some are commercially available and others are in various stages of development or field testing. The cost of some of these sensors may be considerably lower than the cost of new CTs and PTs, particularly when considering total installed costs. Therefore it is natural to consider various alternative sensing means as inputs to the DFA.

Variations in the transfer characteristics of sensing devices will have an effect on 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 various 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 considerations. 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.

Summary and Current Status

Distribution Fault Anticipation prototypes currently are installed in 14 substations, monitoring 60 feeders. These installations have provided a wealth of data that has led to the better understanding of failure processes of line apparatus. Researchers at Texas A&M have documented numerous failures and failure precursors and have developed techniques for recognizing many of the underlying power system causes.

There are many factors to consider for successfully transitioning this technology from a research project to widespread availability and deployment by utility companies. Researchers currently are developing and refining requirements for system integration, in parallel with efforts by the commercializer of the technology to develop a standalone platform for further field demonstration of the technology in day-to-day utility operations. Results from the conceptual design efforts will be more fully reported in the final report when this phase of the project concludes at the end of 2007.

3
DATA COLLECTION AND SELECTED CASE STUDIES

The Phase II project resulted in instrumentation of approximately 60 feeders in 14 substations at 11 host utility companies. This created a substantial infrastructure of data collection equipment that continues to operate and collect data.

In addition to developing system integration concepts in the current Phase III project, researchers continue to collect data from this existing network of data collection systems. The project team also continues to support utility engineers in the interpretation of anomalies that occur on their systems and are recorded by Distribution Fault Anticipation (DFA) prototypes.

The DFA prototypes record numerous episodes of faults, incipient faults, and operational problems with power system apparatus. Many of these episodes are similar to events recorded one or more times in the past. For types of events that already have significant representation in the existing database, additional episodes allow researchers to assess the efficacy of characterization algorithms and to make adjustments where suboptimal performance is observed. For those types of events that have been captured previously, but for which there are relatively small numbers of episodes in the existing database, additional episodes allow researchers to make characterization algorithms more robust than they otherwise might be. Finally there are failures of types not previously recorded or documented during any previous phase of the project.

The following subsections provide three illustrative examples of events recently recorded. The utilities involved in these cases had no monitoring equipment to tell them failures were developing or to help them assess problems after they occurred, other than the DFA.

Case Study: Substation Cable Failure

One substation with a Distribution Fault Anticipation (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. Power 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.

Shortly after 11:00 AM on the day in question, there was a violent failure in one of the power 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 3-1 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.

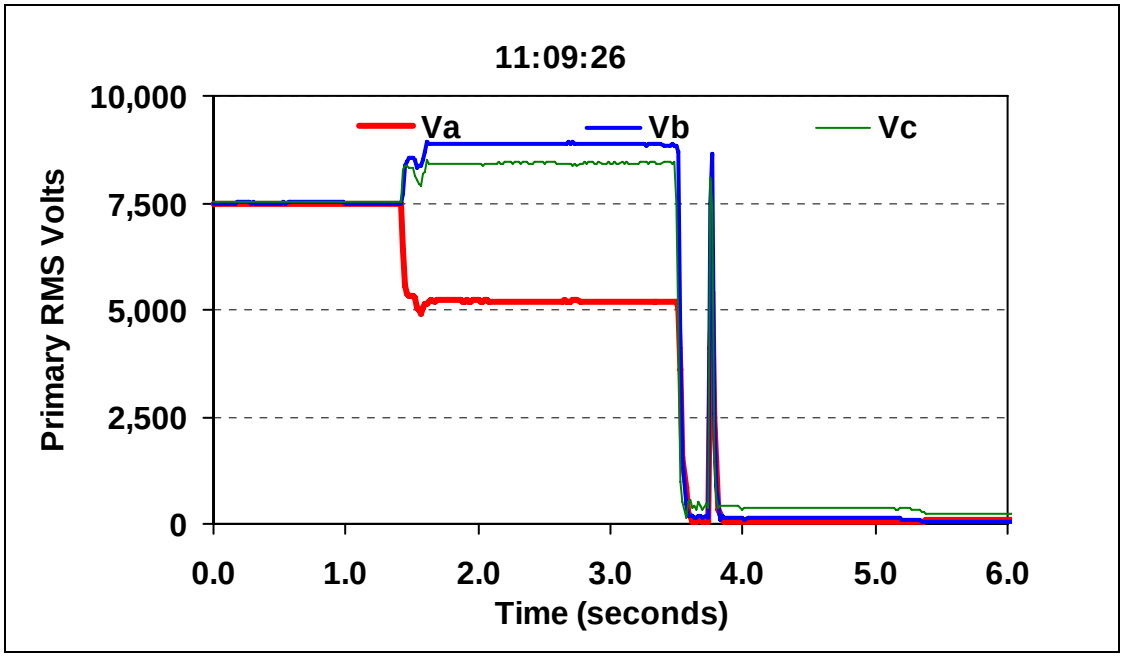

Figure 3-1
Voltages during Cable Failure

Interestingly, 13 cycles after substation protection tripped the transformer and removed power from the faulted cable, the voltage was restored 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). The utility is investigating the failure and fault and assessing the behavior of protective devices, but the preliminary assessment based on DFA data is that a normally open bus tie switch closed automatically in response to the transformer tripping off. This momentarily fed the fault from another substation transformer for this period of 1-1/2 cycles.

Figure 3-2 shows anomalous phase-A RMS 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 dips occurred in the phase-A voltage, one of which is illustrated in Figure 3-3. Then, 108 seconds after the initial anomalies, the ultimate fault of Figure 3-1 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 3-2)
- 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 3-3)
- 11:08:58 – Voltage dip recorded at bus
- 11:09:26 – Sustained voltage dip (final fault), followed by trip 2.1 seconds later (Figure 3-1)

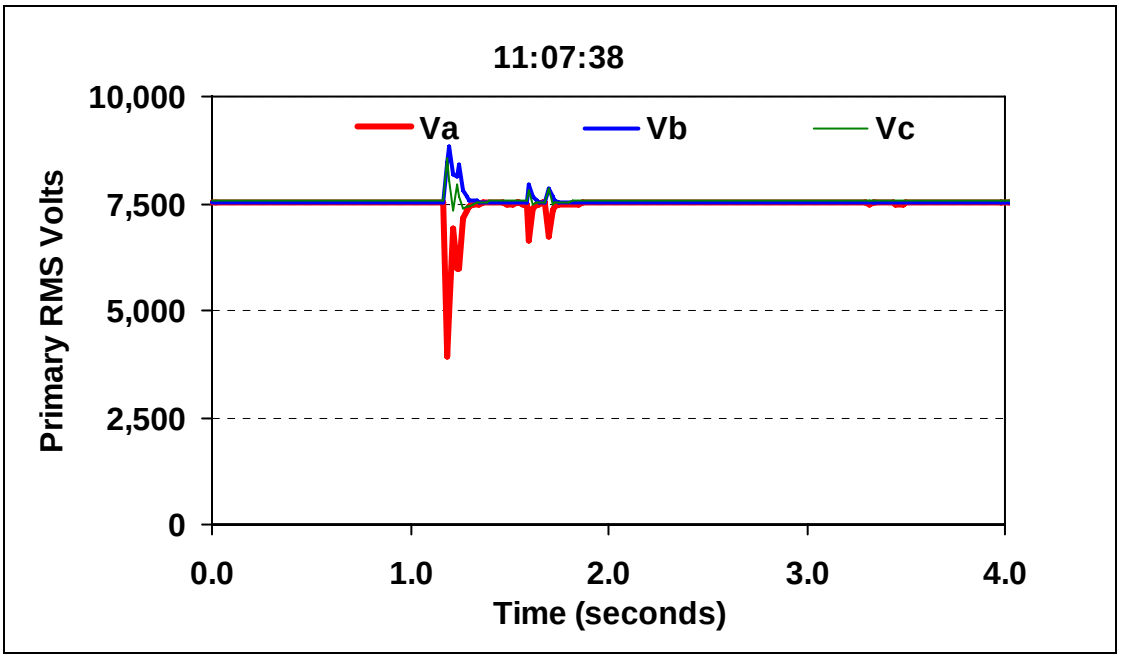

Figure 3-2
First Voltage Anomaly Preceding Cable Failure

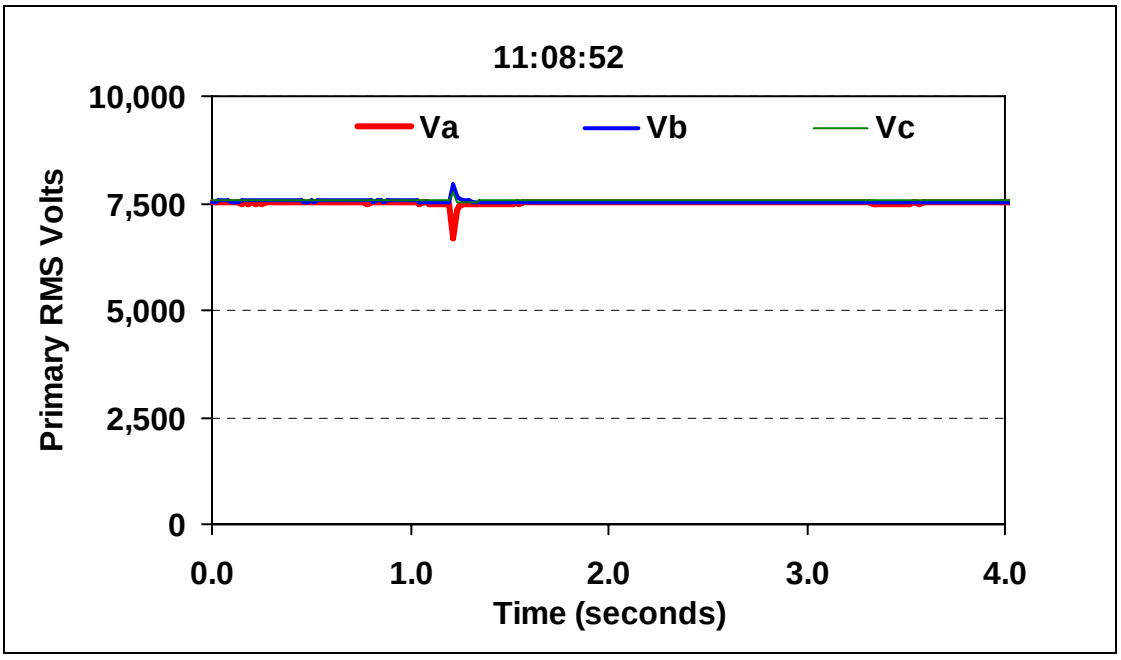

Figure 3-3
Fourth Voltage Anomaly Preceding Cable Failure

The DFA has recorded multiple instances of distribution cable failures. It also has recorded precursors prior to many of these episodes. The elapsed time between when precursors have been detected and when the cable ultimately fails varies considerably. In some cases there is no precursor activity 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.

The failure of this substation cable represents new knowledge for the DFA database. This is the type of event that is statistically infrequent but that can have significant impact on reliability when it does occur. A single outage affecting 26,000 customers for an average of 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.

The initial intent of the DFA has been to detect failures and developing 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 is such that its voltage inputs come 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 interesting. Analysis shows that the voltage characteristics before and during this substation cable fault were very similar to voltage characteristics before and during multiple previous examples of failures of cables that serve end customers. This is quite significant in that it seems reasonable to extrapolate from this incident to say that there is a high probability 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 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, previously documented examples of cables serving end users have shown that a significant number of these begin to 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 typically has in its distribution substations. Other than the DFA, the utility in this case had no other electrical information to help it perform a root-cause analysis. 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: Failing Transformer Bushing

A DFA prototype registered an overcurrent fault at 07:39:58 on December 11, 2005. The fault produced approximately 2 400 RMS amps of fault current. A single-phase poletop recloser (i.e., not the substation breaker) tripped it after two cycles and then the recloser closed back in two seconds later, at which point the fault did not persist. There was nothing particularly remarkable about this event. The protective device detected and cleared an overcurrent fault and there were no outages or customer complaints. The utility company was unaware that anything had happened, except from the DFA.

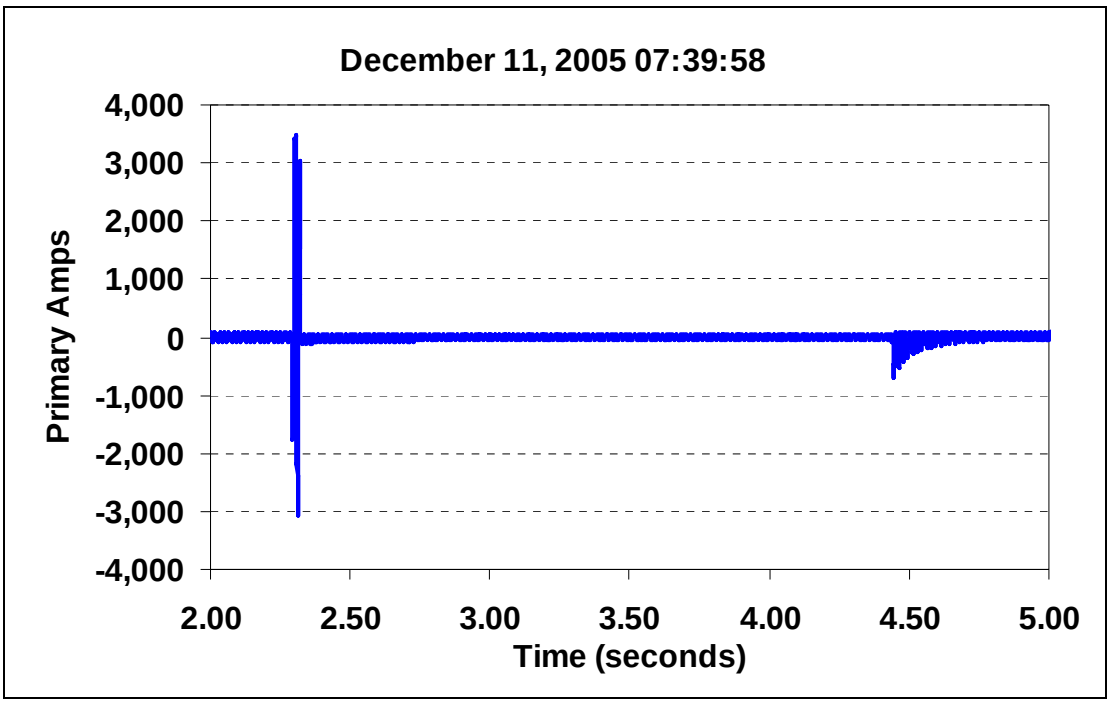

Figure 3-4
Routine Single-Phase Fault Cleared by Poletop Recloser

Another fault happened two days later, at 8:21:05 on December 13, 2005. The fault produced approximately the same current level as the event two days earlier and it was on the same phase. A single-phase recloser again interrupted the fault after two cycles and closed back in two seconds later. As before, there was no outage, there were no customer complaints, and the utility had no indication of the event, except from the DFA.

Alerted to these 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 to find the problem in less than one hour. They found a poletop service transformer (see Figure 3-5) with a damaged bushing intermittently causing a short circuit. They also found a dead squirrel at the base of the pole. The obvious conclusion was that the animal's body had caused the first short circuit (December 11, 2005). The poletop recloser cleared the fault properly. The squirrel's body fell away and did not result in a permanent fault. However, the short circuit across the transformer bushing caused permanent damage to the bushing. This compromised the bushing's insulating ability and resulted in the later fault.

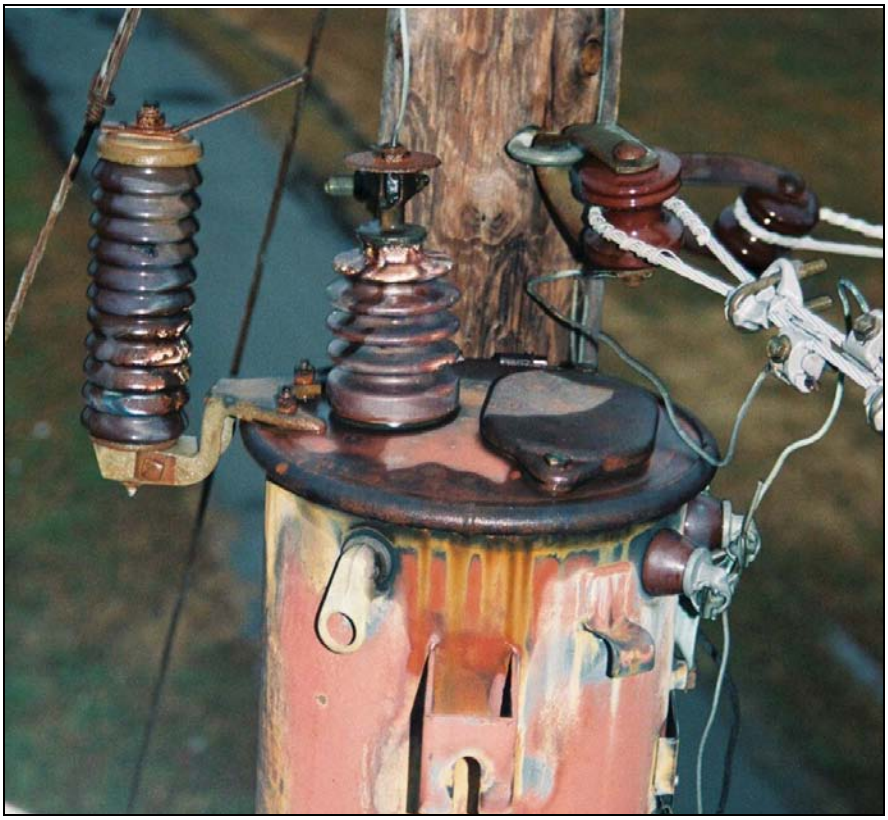

Figure 3-5
Poletop Transformer with Damaged Bushing That Caused Intermittent Faults

After identifying the problem, the utility added replacement of the transformer to its work list. Before the repair was made, 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 interesting and instructive from a research perspective. It provided evidence that the damaged insulator would continue to cause intermittent faults. Repetitive short circuits and arcs are known to escalate and create larger problems if left uncorrected. 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 that can ignite proximate items and structures.

The feeder on which the faults occurred was a long, rural circuit with approximately 20 reclosers on it. The utility used information from the DFA to narrow the search to a much smaller area, allowing them to find the failure efficiently. This is significant, because the normal process of finding an intermittent fault is tedious and time-consuming, particularly on a long feeder. A search often begins with a customer complaint about "blinking" or "flickering" lights. Customers generally are not able to differentiate between voltage sags and momentary interruptions. Therefore the utility has little clue about whether a problem really exists on the distribution system, what kind of problem it might be, and where it is located. It is common 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 found the problem in less than one hour in one trip.

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

- Identification that a problem was developing – Absent the DFA, the utility was unaware that a problem existed from any other source. No other device indicated any problem and there were no customer complaints to alert the utility to the problem.
- Locating the problem – Locating a fault can be difficult. It becomes even more difficult when it is an intermittent fault that has not caused an outage, particularly when the circuit is long and geographically dispersed. All of these factors came into play in the subject event. The utility was able to use the DFA to locate this problem with a two-man crew in less than one hour.
- Zero customer complaints – This incipient failure was detected and repaired without any event that caused any customer complaints whatsoever.

Case Study: Misdiagnosed Cable Failure

Customers reported an outage on the evening of April 2, 2006. A troubleman 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 a cause code indicating lightning as the suspected culprit.

Early on April 5, 2006, the same customers experienced another outage. The same fuse location that was blown three days earlier was blown again. It was not possible to restore service this time by replacing the fuse. 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 troubleman 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 troubleman did not have this information available to him, however, resulting in the incorrect diagnosis and the premature closing of the trouble ticket. Figure 3-6 illustrates waveforms recorded during the initial outage.

Several hours after the initial service restoration, the DFA recorded the precursor activity shown in Figure 3-7. This measurement indicated characteristics of a cable beginning to fail, but this episode did not result in an outage. Another episode (not shown) occurred on the afternoon of April 3, now some 18 hours after service had been restored on the evening of April 2. This episode also was characteristic of a cable failing, but again, no outage occurred.

There was no further activity until the third day after the initial fault, at which time the DFA recorded additional cable precursors that culminated in the fuse operating again at the final failure of the cable. Figure 3-8 illustrates current measured during this final failure.

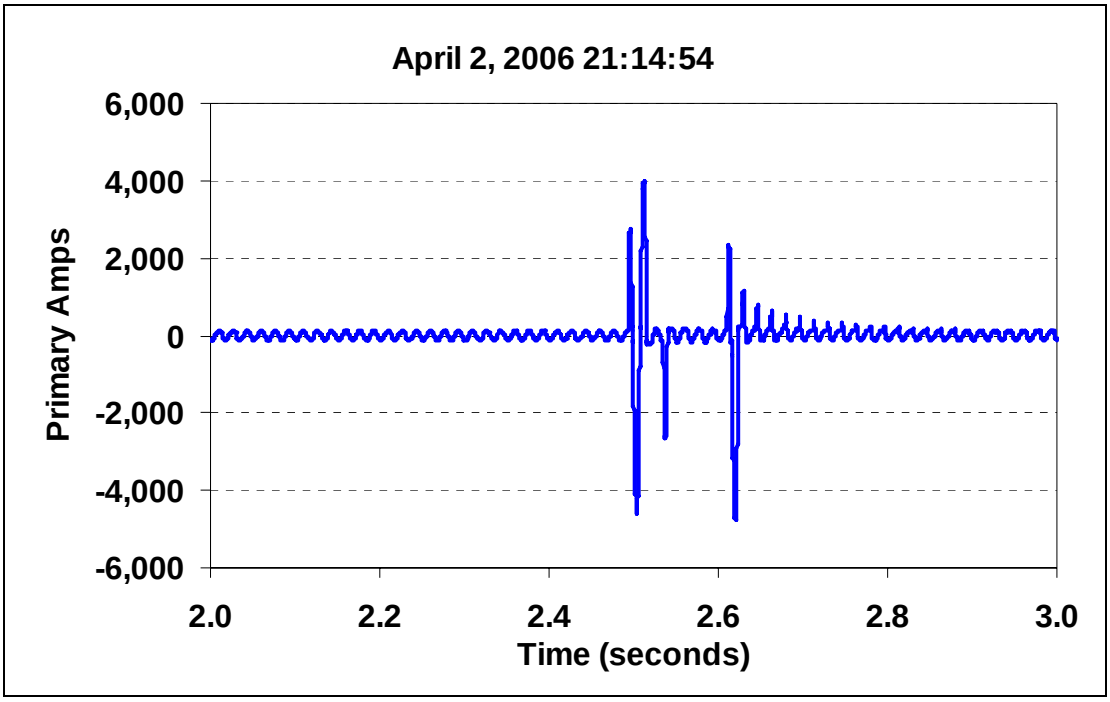

Figure 3-6
Current Waveforms during Fault on First Evening

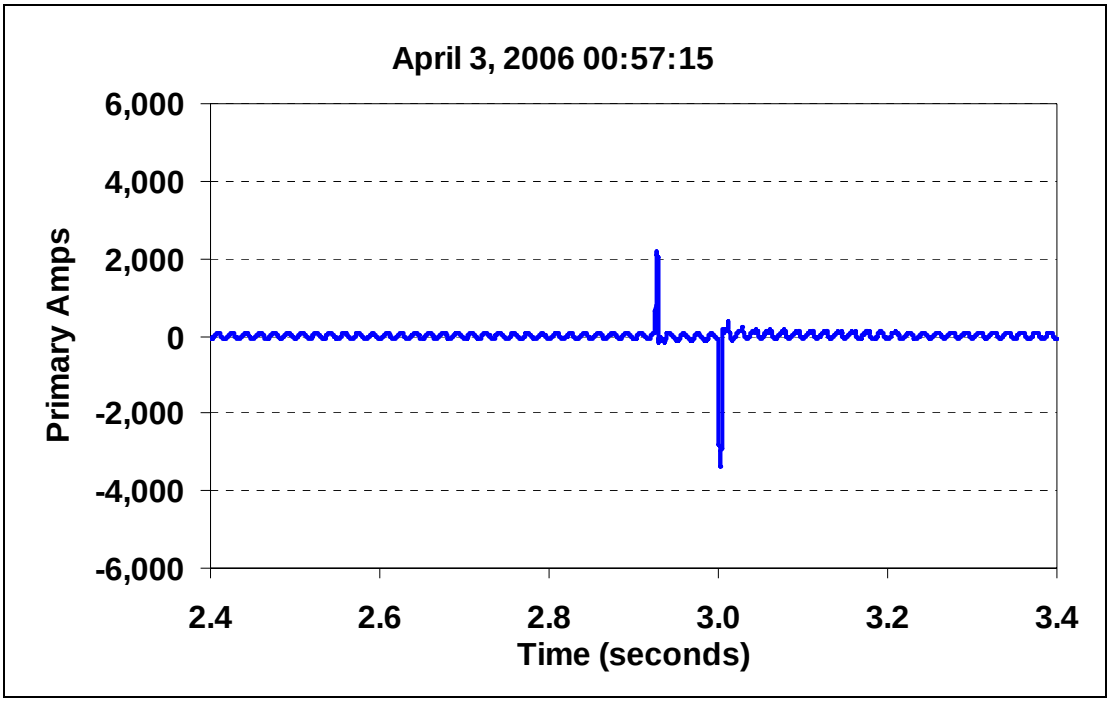

Figure 3-7
Precursor Signals Several Hours after First Service Restoration

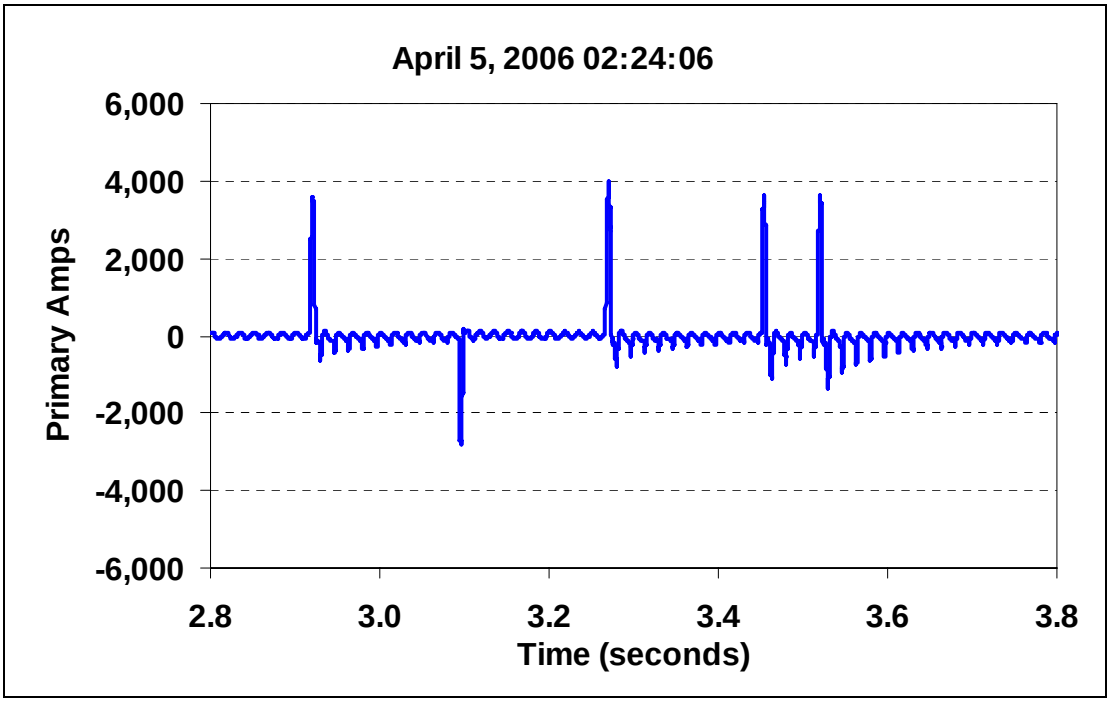

Figure 3-8
Final Failure of Cable on Third Day after Initial Outage

This case illustrates an interesting use of DFA technology. The initial failure on the evening of April 2, 2006, provided little precursor activity or warning period before the outage occurred. However the waveforms produced during that failure process were highly indicative of a failing cable. Armed with this knowledge, a troubleman could respond differently. He still may attempt to replace the fuse, to get service restored to customers quickly. However, he would not close the ticket but rather could make appropriate arrangements to put the cable on a repair list with high priority. That would allow a crew to make repairs during the multi-day period between the initial failure and the final failure and outage.

The additional precursor activity during the next 24 hours also provides an opportunity to respond differently. In the subject case, the troubleman saw no apparent cause for the fuse to be blown and 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 and then starts having additional signs of a cable failure over the next several hours, it becomes abundantly 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: Anomalous Substation Breaker Operation

Figure 3-9 illustrates a phase-B fault that drew approximately 3 400 amps. The substation 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.

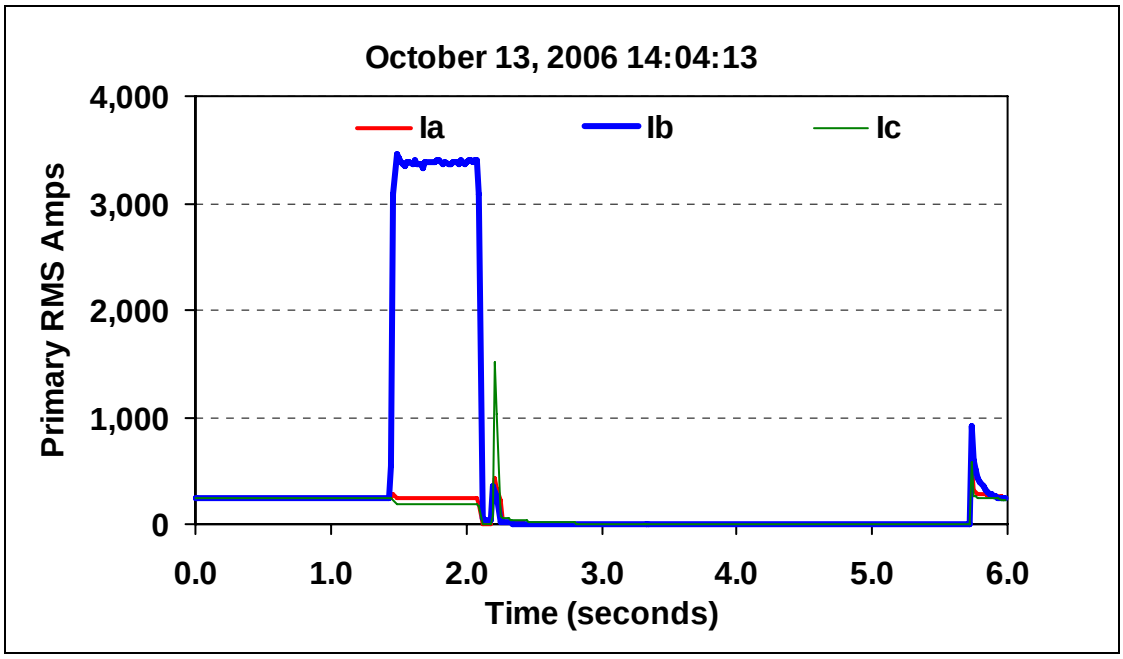

Figure 3-9
Single-Phase Fault Cleared by Substation Breaker Trip and Reclose

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

Figure 3-10 shows the waveforms associated with the fault and the current pulse. Figure 3-11 shows greater detail for the portion of the waveform containing the pulse. The current pulse begins 100 milliseconds after the breaker opened and lasts about 2-1/2 cycles.

This did not represent intended operation of the protection system and 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 that a possible explanation for the observed behavior is that the instantaneous "shot" of the reclosing relay at the substation may have closed its contacts while the overcurrent relay's trip contacts were still engaged. This caused the breaker to reclose but to immediately open again as soon as the reclosing relay's contacts opened. Based on this observed anomaly, the utility examined DFA records for prior operations of that substation breaker and found that it experienced a very similar sequence of events approximately six months earlier. At the time of this writing, the incidents and their causes remained under evaluation.

This case is an example of how DFA data can be used to identify anomalies and problems with regard to 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 unusual or improper protective operations.

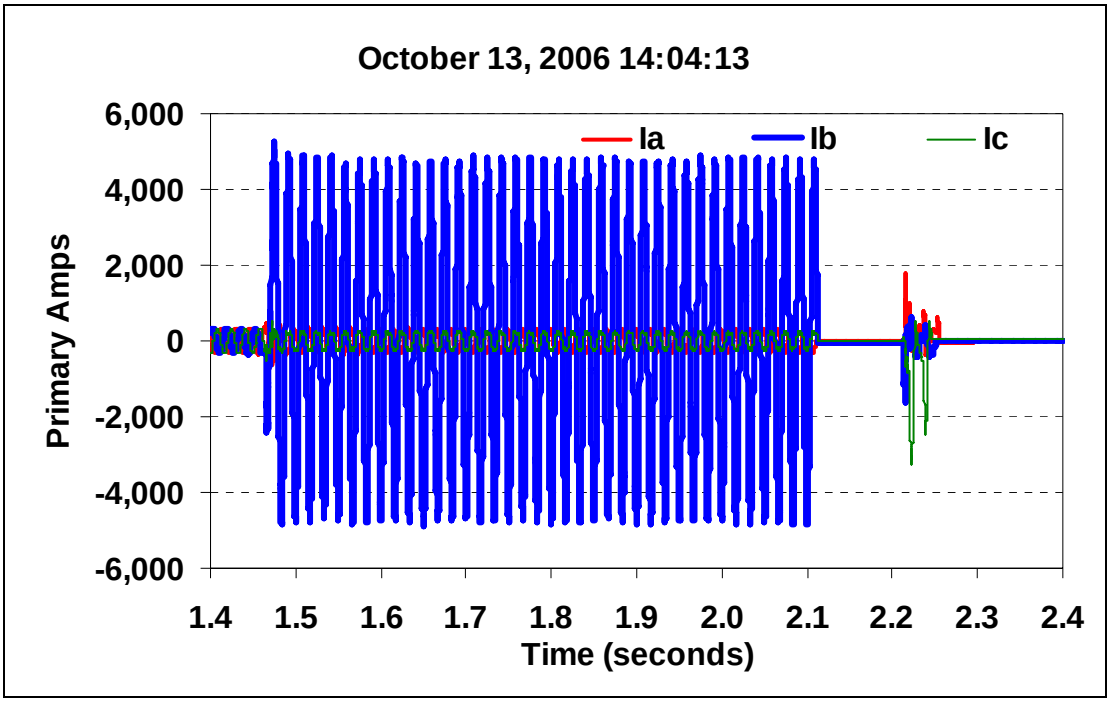

Figure 3-10
Single-Phase Fault with Short-Lived "Pulse" of Current after Breaker Tripped

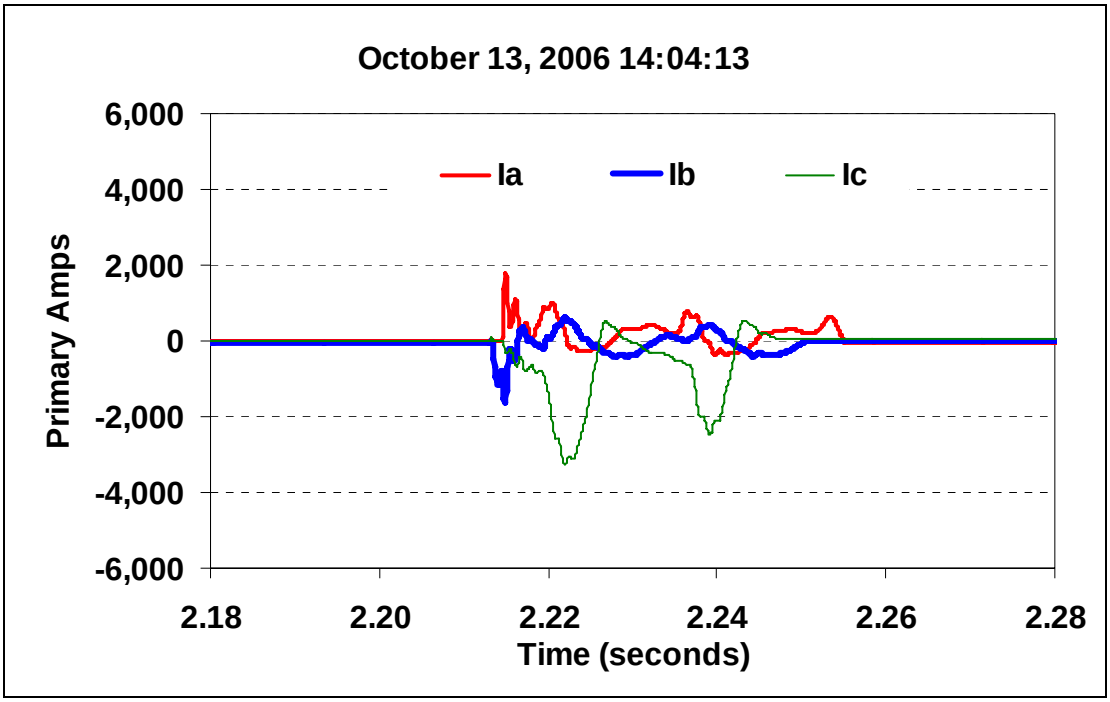

Figure 3-11
Detailed View of Current "Pulse"

Concluding Remarks

Researchers continue to take advantage of the network of prototype DFA monitoring systems put in place during Phase II of this project. They continue to provide 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. These provide the 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 have documented 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 several examples of the types of failures that the DFA detects. None of the utilities involved in these cases had information regarding the subject 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 most of the common failure modes on distribution feeders. Ongoing data collection efforts continue to take advantage of the existing system of monitors to gather data about additional failure modes that are statistically less common. It is important to note that failure modes that are statistically less frequent may have vastly more significant impact on system reliability when they do occur. The case study about the substation cable failure provides a dramatic illustration.

4
COMMERCIALIZATION STRATEGY AND STATUS

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.

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 previous phase of the DFA project. The model and the rational are reproduced here in their entirety 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 4-1 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.

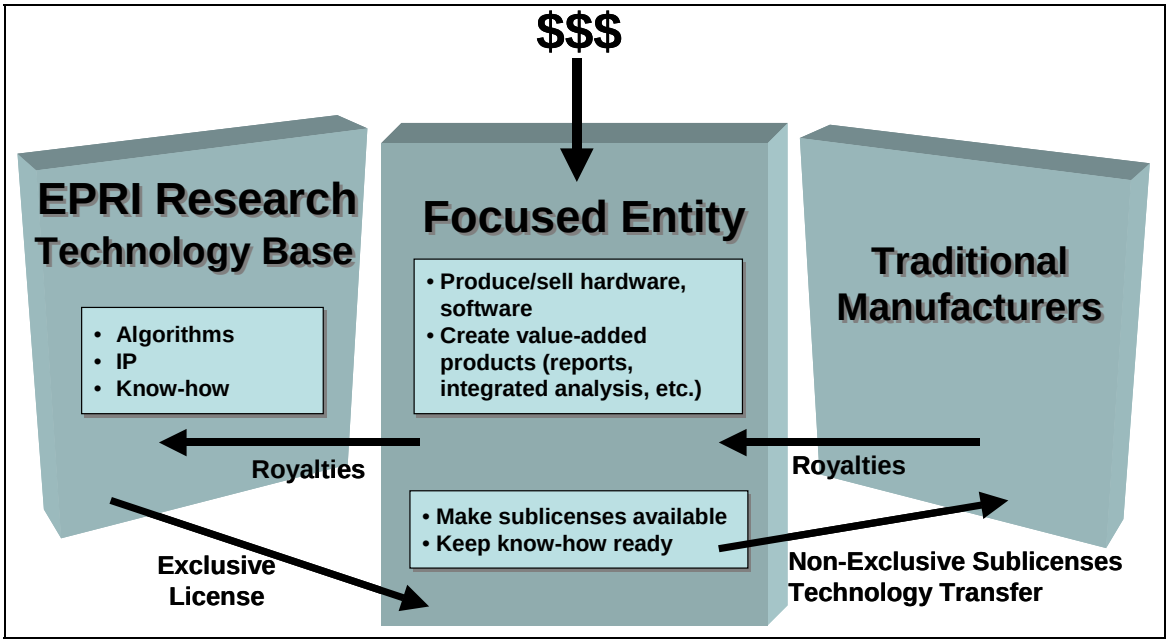

Figure 4-1
Commercialization Model for DFA Technology

Intent of Exclusive License

Figure 4-1 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 the third quarter of 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 very knowledge intensive technology. It also is apparent that DFA technology has much more potential to offer 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 currently is in discussions with multiple third-party manufacturers about how those manufacturers might incorporate DFA technology in their product lines. Participating utilities are encouraging their vendors of choice to consider adding DFA technology to their product lines as well.

5
CURRENT STATUS

EPRI-funded research at Texas A&M has demonstrated the ability to use sensitive monitoring to perform a variety of functions on distribution systems, including detecting precursors to incipient failures, recognizing operational problems with apparatus, and performing root-cause analyses when problems arise. Prior work on this project demonstrated these capabilities through prototype Distribution Fault Anticipation (DFA) equipment that monitors 60 feeders in 14 substations across North America. These devices help document the ability to detect the above-mentioned problems and give a flavor for the wide variety of uses for which such a system could be used in day-to-day operations.

The research team continues to take advantage of the existing network of prototype DFA equipment. They continue to collect vast amounts of data from these systems. The data includes additional examples of previously documented problems, allowing researchers to validate and refine existing characterization techniques. The data also includes previously undocumented events. These provide additional knowledge about equipment failure processes and their precursors, and suggest new functionality for the DFA. Some failure modes are statistically infrequent but may have very significant impact on system reliability when they do occur. A dramatic example of this is failure of a main substation cable. The first such failure to occur in a DFA-monitored substation did not happen until several years into the collection period. Though statistically infrequent, singular events of this type significantly impact reliability indices, as well as causing other problems for utility companies.

The DFA prototype systems were designed for research purposes and therefore use highly centralized approaches to data management, analysis, and characterization. The system hierarchy and implementation of the prototypes are not conducive to widespread deployment by utility companies or integration into their operational and business practices. The current System Integration project is studying concepts related to making Distribution Fault Anticipation (DFA) technology useful in widespread practical application and is examining a wide variety of interrelated issues. This effort is scheduled to continue through 2007.

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 allows PSI to market the 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 the vast majority of individual utility companies can obtain the technology from their preferential providers, rather than being captive to a single manufacturer. PSI will offer technology transfer and support services to third-party sublicensees who desire this service.

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