Using Event Recordings to Verify Protective Relay Operations

By

A. T. Giuliante	**ATG Consulting**
D. M. MacGregor	**Electrocon International**
A. & M. Makki	**SoftStuf**
A.P. Napikoski	**United Illuminating Co.**

Presented at the

Energy Council of the Northeast Spring Conference
Portsmouth, NH
March 11, 2004

Using Event Recordings to Verify Protective Relay Operations

A. T. Giuliante   D. M. MacGregor   A. & M. Makki   A.P. Napikoski

1. Introduction

Digital Fault Recorders (DFR) and modern microprocessor-based relays have records consisting of oscillographic waveforms and event logs that can give the necessary information needed to describe the nature of a fault. With the proper set of state-of-the-art software tools, an engineer can create summary files that can be played back into a relay system simulator used to evaluate the relay's response to a fault.

This paper will present techniques on how to read, interpret, modify and convert DFR files [1] stored in the COMTRADE format [2] so that they can be played back into a relay system simulator [3]. The relay system simulator calculates the relay's response by using detailed phasor models of the relay elements, including TOC curves and distance-element comparators [4 and 5]. In addition, the process of creating a COMTRADE file to perform a transient simulation test [6] will also be presented. These techniques will be used to analyze and validate actual relay performance during a line fault on a 345 kV line.

2. Sources of Digital Fault Records

As Utilities replace their aging infrastructure with serially accessible devices, the need to integrate all substation microprocessor devices onto one user-friendly platform becomes imperative. The ability to interrogate DFRs, microprocessor relays, smart meters and monitors quickly and efficiently becomes a high priority in a competitive customer oriented and down sized environment. Integrating and utilizing the present microprocessor arrangements for capturing data such as relay targets, or oscillographic data adds value to the Utility.

The capabilities to quickly retrieve fault information and to automatically assign a unique file name are the first steps in successfully obtaining a database of fault records. Once data is retrieved, fault records can be viewed in their native formats with a universal viewer and analyzed with the proper suite of analysis tools. Selected channels of three-phase voltages and currents can be easily converted into COMTRADE files and played back to relays to correctly evaluate a relay's response to a fault.

A common way to retrieve information today is to use a serial port switcher. These are serial ports that are directly connected to substation devices and can be remotely controlled using dial-up or LAN connections. The remote access routines provide secure communications via multiple passwords that are required to gain entry into the system. Once remote access is established, the user may port switch to any connected device. The port switch routines allow direct communications in ASCII or Binary and the received data records are assigned unique filenames and saved to the database of fault records (repository) as shown in figure 1.

Current application programs automatically establish remote access and switch to any connected device. The devices are periodically polled or polled upon demand. Periodic polling functions allow for continuous monitoring of device status in order to automatically detect the occurrence of events within a few seconds from actual occurrence. Upon occurrence, the event records are retrieved, saved in files and then transferred to the repository (report by exception.).

State of the art communication technologies offer real time capabilities with point-to-point connectivity. You can simultaneously gather information from multiple devices. These communication technologies allow for real time capture of fault records from large numbers of recording devices.

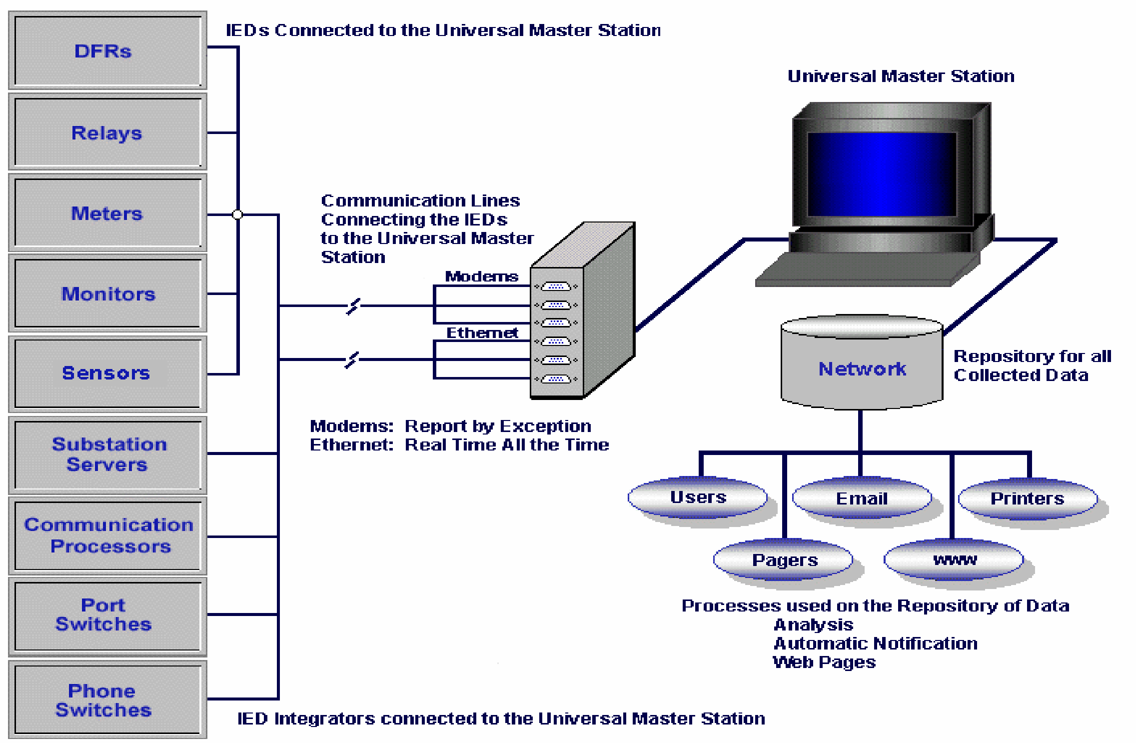

Figure 1 - Capture of Information.

3. The "Event"

On July 22, 2001 a phase C to ground fault occurred on a 345kV transmission line (line number 387) through tree contact. The relays at the remote end tripped via the carrier blocking scheme. No carrier tripping occurred at the local end. The local end tripped sequentially by the zone 1 electromechanical reactance type ground distance relay. The total clearing time was 8.4 cycles.

The lack of high speed local tripping created a concern and triggered an investigation to determine the relay system's response to the fault.

4. Analysis

Only one DFR was installed to monitor the transmission line, but fortunately it was located at the local-end substation where the analysis was required. The first part of the procedure used for the analysis was to:

1. Read DFR file
2. Select channels monitoring relay inputs
3. Set the order of channels
   Va, Vb, Vc, Ia, Ib, Ic
4. Save as a COMTRADE file
5. Validate waveforms
   a. Scaling – True peak versus RMS peak
   b. Phasing – Correct load flow

The DFR installed at the local-end substation was a multi-channel RIS 1620. Step 1 was to read the DFR file and to save it in the COMTRADE format with file name "3870722". The event record is shown in figure 2.

Step 2 was to select the three voltage and three current channels monitoring the relay inputs for transmission line 387. As shown in figure 2, the channels are:

Channel No.	Channel Name
7	387 IA C 387 LINE PH. A CURRENT
8	387 IB N 387 LINE PH. B CURRENT
9	387 IC A 387 LINE PH. C CURRENT
17	387 VBN A 387 LINE PHASE B-N VOLT
18	387 VCN B 387 LINE PHASE C-N VOLT
23	387 VAN C 387 LINE PHASE A-N VOLT

Steps 3 and 4 were to set the order of the channels for Va, Vb, Vc, Ia, Ib, and Ic and to save as a new COMTRADE file. The original file is legal record and must not be modified. Figure 3 shows the new COMTRADE file saved with file name "3870722 Voltages and Currents".

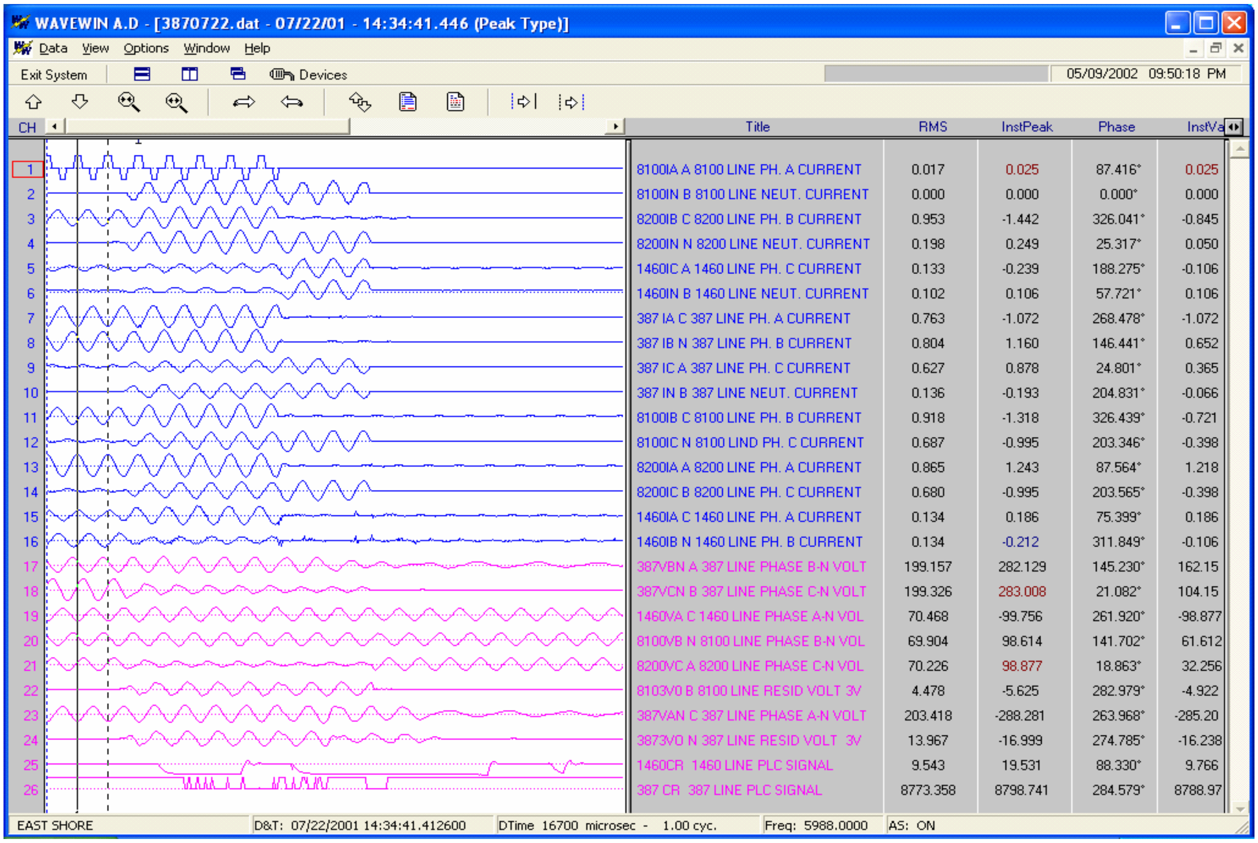

Figure 2 – 3870722 Event Record.

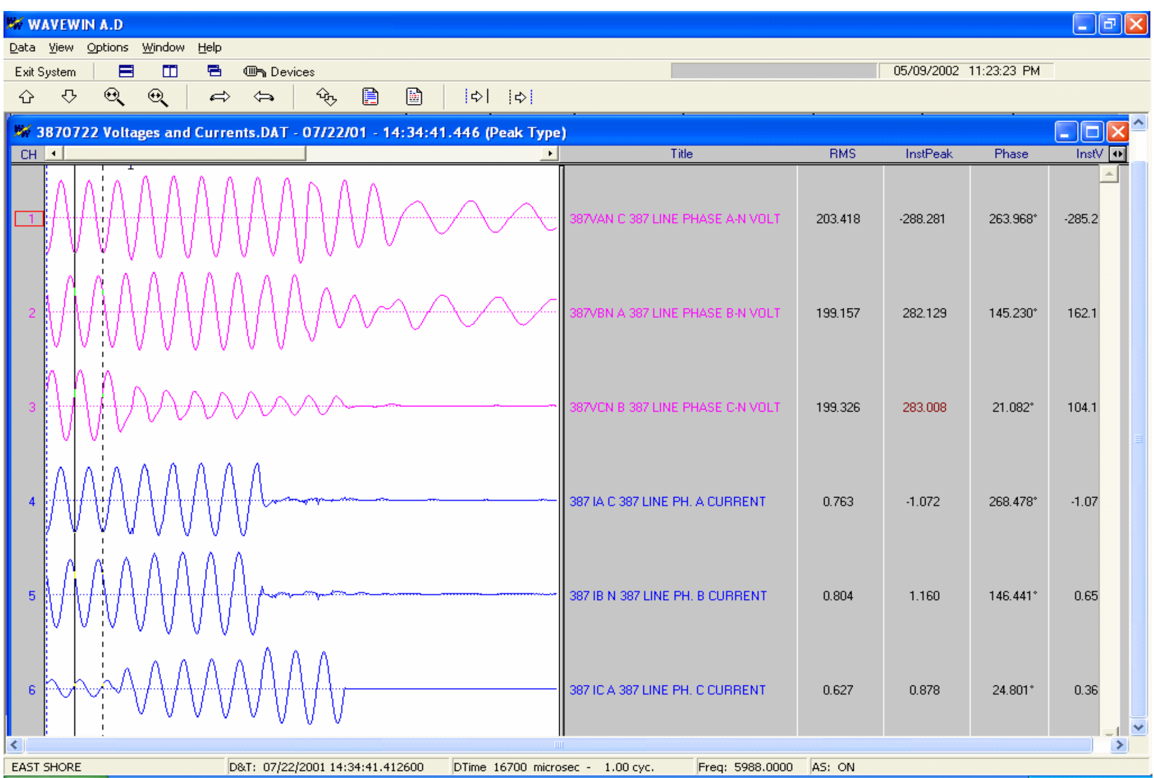

Figure 3 - 3870722 Voltages and Currents.

Step 5 was to validate the waveforms. This entails confirming that the scaling and phasing are correct. Some Utilities still use the practice of scaling their DFR systems to read RMS for peak value. This practice is a carry-over from the days of paper oscillographs where it was quicker and easier to obtain the RMS value by drawing a horizontal line from the peak of a waveform to the vertical axis that provided the scale for the measured channel.

For the 38700722 event, the voltages were checked and found to be calibrated in true RMS. For a 345kV system, the true RMS is 199.186 kilovolts (345/√3). Figure 4 shows the measured voltages with the correct values that range from 199.157 to 203.418 kilovolts RMS. The difference is due to the system unbalance.

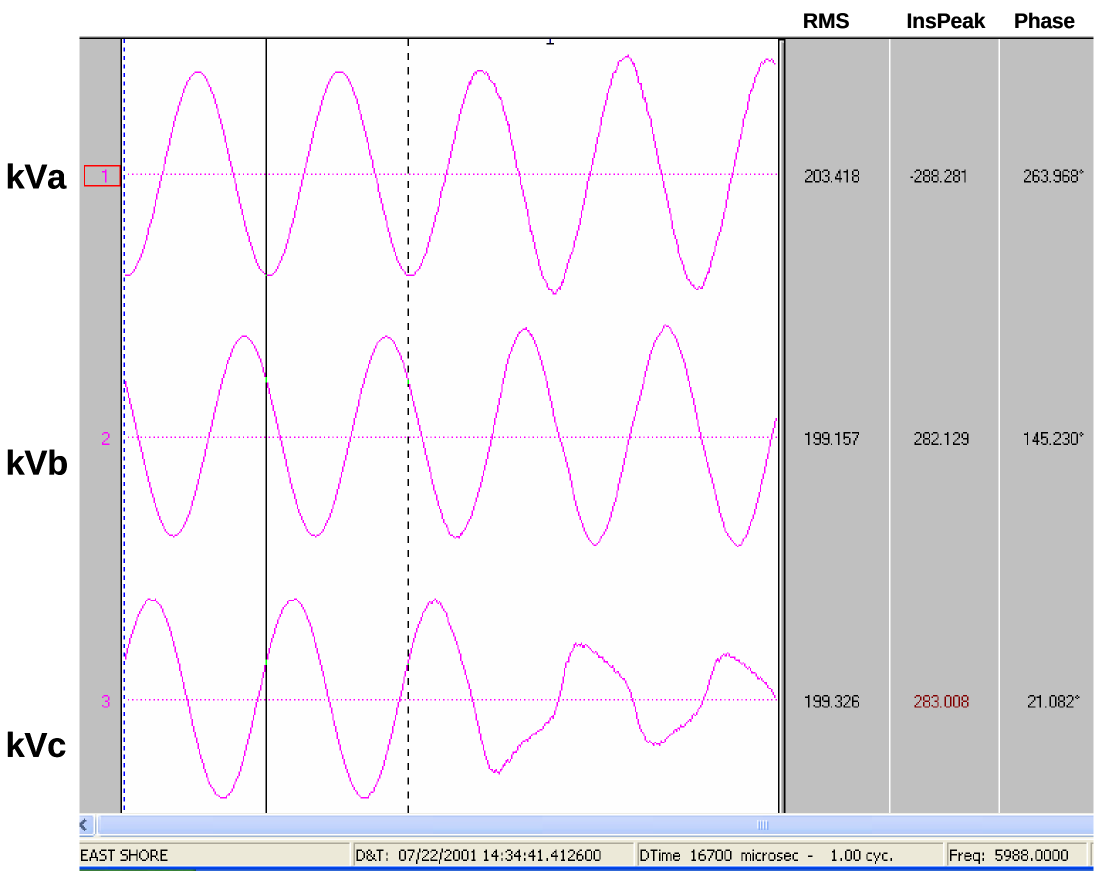

Figure 4 – Correct Scaling.

The phasing was checked next to confirm that the CT connections were properly wired. Figure 5 shows the summary of the measured magnitudes and angles at one cycle into the record before the fault occurred.

Time (cyc)	1.00	
	Pre-Fault	
Primary Values	Mag	Ang
kVa	203.418	263.97
kVb	199.157	145.23
kVc	199.326	21.08
kIa	0.763	268.48
kIb	0.804	146.44
kIc	0.627	24.80

Figure 5 – Measure of Load Flow.

Comparing the phase angles for each set of voltages and currents per phase indicates that the load flow before the fault was into the line since the phase angles per phase were approximately in phase with each other. However, the load flow was in the reverse direction indicating that the CT connections were incorrectly reversed when the DFR was installed. Therefore, to properly analyze the event, the current channels needed to be reversed.

To reverse the current channels, a universal viewer with state-of-the-art analysis features [7] was used. Figure 6 shows the use of the software analog channels to reverse the currents by defining the titles of the channels and the operator used to reverse the channel.

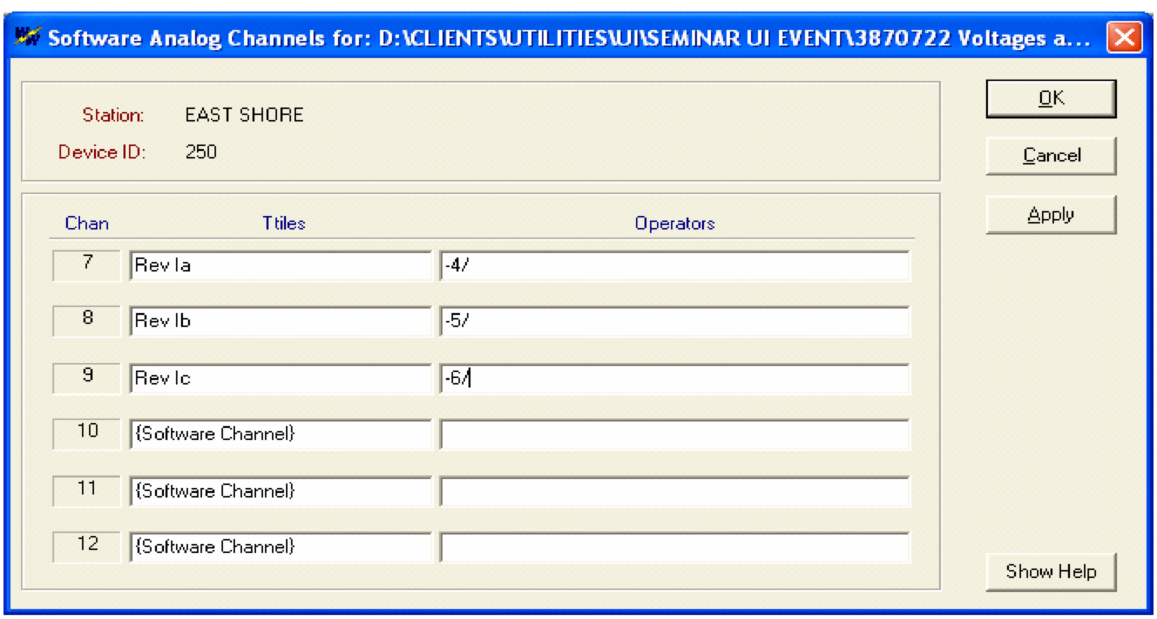

Figure 6 – Reversing the Current Channels.

Figure 7 shows the new COMTRADE file saved with file name “3870722 Voltages and Rev Currents”.

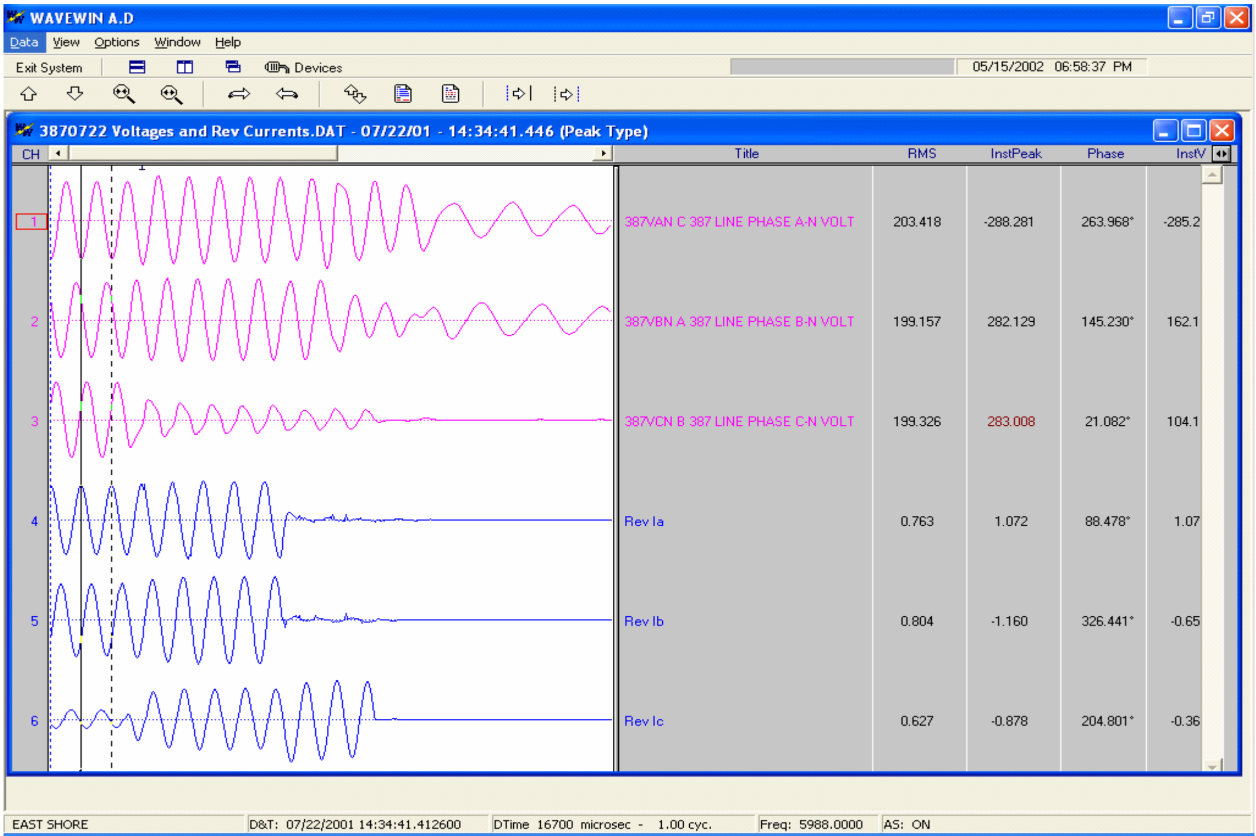

Figure 7 - 3870722 Voltages and Rev Currents.

5. Time Line and Measured Phasor Values

The next step was to create a time line of the event and measure the phasor values at each key time point. To determine when the fault occurred, the channels for 3Vo and 3Io were created by using the software analog channels feature. The time cursor was then moved to the location where the change in 3Vo and 3Io occurred. Figure 8 shows that the fault occurred at 2.26 cycles into the event.

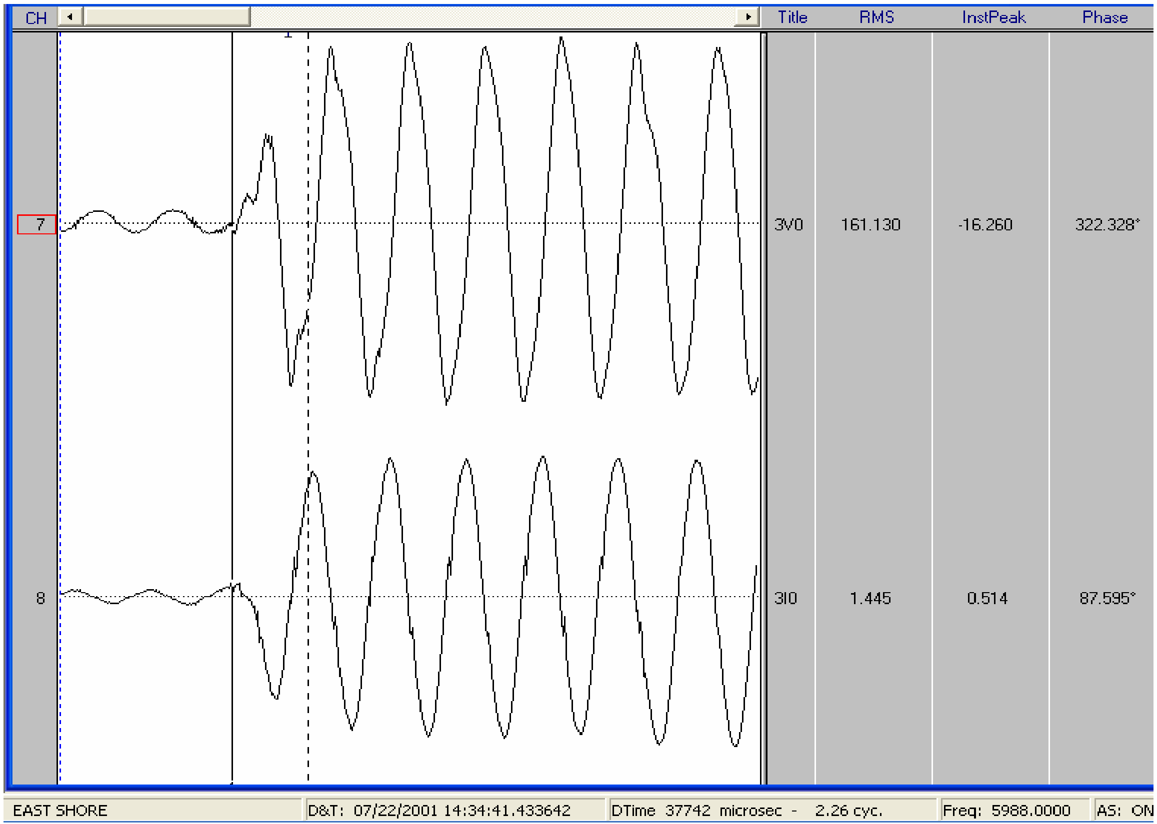

Figure 8 – 3Vo and 3Io waveforms used to find the time of fault.

In a similar way, the other key time points were determined. By moving the time cursor in the waveforms shown in figure 7, the times when the remote and local ends opened were found and noted in the time line shown in figure 9.

	Measure Pre-Fault	Fault	Measure Fault	/--------Remote End Opens--------\ Ph B	Ph A		Local End Opens Ph C
Time (cyc)		2.26		7.60	7.76		10.66

Figure 9 – Time line of fault.

For each of the key time periods shown in the time line, the six phasor values of voltage and current were noted. Figure 10 shows these values referenced to phase B voltage. Since phase B voltage was not faulted, it was used as a reference phasor. Fault 1 shows the initial fault values. Fault 2 shows the fault values with the remote end opened.

	Measure Pre-Fault	Fault	Measure Fault	/--------Remote End Opens--------\ Ph B	Ph A		Local End Opens Ph C
Time (cyc)	0.85	2.26	3.82	7.60	7.76	7.88	10.66

	Pre-Fault		Fault 1		Fault 2	
Primary Values	Mag	Ang	Mag	Ang	Mag	Ang
kVa	203.161	118.72	225.768	101.13	215.001	101.18
kVb	199.428	0.00	213.955	0.00	207.375	0.00
kVc	199.374	235.83	85.646	181.26	54.980	177.20
kIa	0.762	303.25	0.835	294.29	0.091	229.19
kIb	0.805	181.22	0.944	169.12	0.077	239.13
kIc	0.628	59.41	1.921	156.12	2.593	167.34

Figure 10 – Time line of fault with measured phasor values.

6. Fault Location

The accuracy of fault location calculations depends on a number of factors. Some of which are the:

- accuracy of the positive and zero sequence line impedances
- CT and PT accuracy
- method of fault location calculation – single ended vs. double ended

The "IEEE Guide for Determining Fault Location on AC Transmission and Distribution Lines", PC37.114, is a good reference for understanding fault location techniques [8].

For the 3870722 event, fault information was known only at the local end; therefore, a single-ended technique was used to determine the fault location. The 387 line data in secondary ohms is shown in figure 11 along with the K factor [9].

$$Z_{L1} = 2.8019 \angle 85.45^\circ$$

$$Z_{L0} = 8.6450 \angle 70.03^\circ$$

$$K = \frac{Z_{L0} - Z_{L1}}{3\ Z_{L1}}$$

$$K = 0.7126 \angle -22.56^\circ$$

Figure 11 – Line 387 Impedances (sec. ohms) & K Factor Value.

Since the remote end fault information was unknown, the accuracy of a "Takagi" single-ended calculation was unknown. Figure 12 shows the effect of fault resistance and load flow. If the "Takagi" method was used to measure the fault location during the initial fault (Fault 1), there could be significant error for a non-homogeneous system.

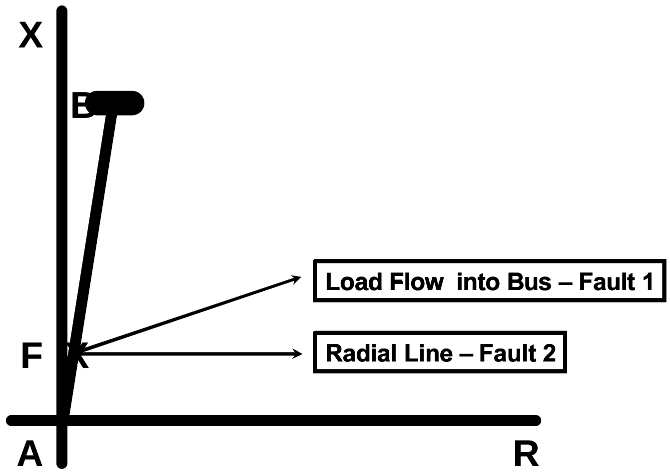

Figure 12 – Effects of Fault Resistance and Load Flow.

During Fault 2, where the remote end opened, the faulted line is radial and the error due to fault resistance and load flow is substantially eliminated. Figure 13 shows the line loop impedance parameters for the radial line during Fault 2.

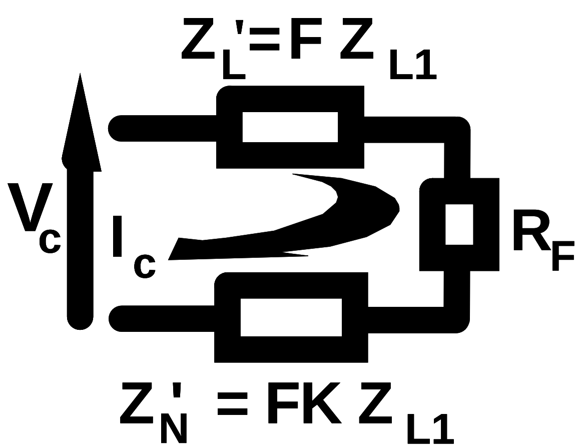

Figure 13 – Radial Line Loop Impedance.

Since the line impedance values were given in secondary ohms, the measured phasor values were converted into secondary quantities using CTR equal to 400 and PTR equal to 3000. Figure 14 shows the secondary values.

	Pre-Fault Mag	Pre-Fault Ang	Fault 1 Mag	Fault 1 Ang		Fault 2 Mag	Fault 2 Ang
Va	67.72	118.72	75.26	101.13	Va	71.67	101.18
Vb	66.48	0.00	71.32	0.00	Vb	69.13	0.00
Vc	66.46	235.83	28.55	181.26	Vc	18.33	177.20
Ia	1.905	303.25	2.088	294.29	Ia	0.228	229.19
Ib	2.013	181.22	2.360	169.12	Ib	0.193	239.13
Ic	1.570	59.41	4.803	156.12	Ic	6.483	167.34

Figure 14 – Measured Phasors in Secondary Values.

The secondary loop impedance was calculated for Fault 2 as shown in Figure 15.

$$Z_{Loop} = \frac{V_C}{I_C} = \frac{18.33 \angle 177.20}{6.483 \angle 167.34}$$

$$Z_{Loop} = 2.827 \angle 9.86 = 2.785 + j\ 0.484$$

Figure 15 – Calculated Loop Impedance for Fault 2.

The fault location can be determined by equating the imaginary parts of the calculated loop impedance to the circuit loop impedance defined by K and ZL1 [10]. See Figure 16.

$$F = \frac{\mathrm{Im}\{Z_{Loop}\}}{\mathrm{Im}\{Z_{L1}(1 + K)\}}$$

$$F = \frac{.484}{4.57} = 10.6\ \%$$

Figure 16 – Calculated Fault Location Using Loop Impedance Method.

As shown in figure 16, the calculated fault location was 10.6% from the local end. The actual fault location was found at approximately 3.2 miles from local end. With the total line length of 32.8 miles, the actual fault location was 9.8 % from the local end. The difference represents two to three tower spans.

7. Playback

Two types of playback methods were used to evaluate the relay performance. The first method used a relay system simulator that evaluated the relay operation using detailed phasor operating equations [11]. The second method used a transient simulation test to playback a modified COMTRADE file into a digital line relay using power system simulator test equipment [6]. The digital relay was evaluated to check how it would perform under the same power system conditions.

7.1 Relay System Simulator

A summary file of fault information was created in the required format to play it back into a relay system simulator used to evaluate the relay's response to the fault. The relay system simulator includes a library of detailed relay models of the relay elements [3]. The relay's response is presented graphically and shown in figures 17 and 18. They give a qualitative picture of the events and the relay's response.

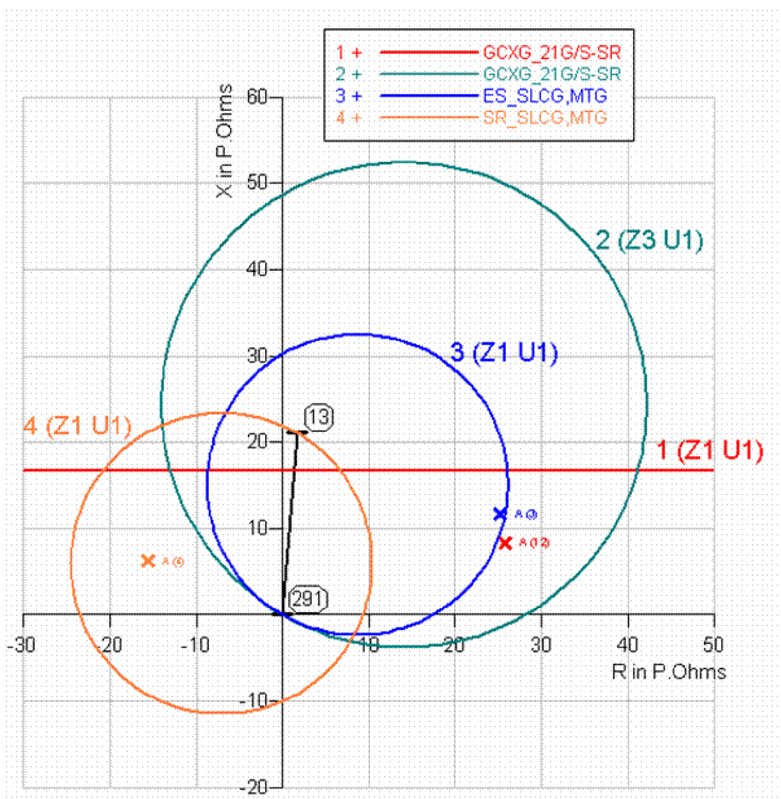

Figure 17 – Relay's Response to Initial Fault.

The relays at the local end see different apparent impedances because their zero-sequence compensation factors were set differently (70% and 60%) [4 and 12]. Hence, the same fault gives two different X marks on the plot. Neither relay operated for the initial fault. With the computed fault resistance (14 ohms), the static relay barely should have operated and the electromechanical relay definitely should have operated. However, the secondary phase current was 4.803 amps and it was low enough to increase the actual relay operating time to several cycles. The remote end pilot relay operated and opened the remote breaker. The apparent impedance seen by this relay is well within its characteristic.

Figure 18 shows the relay's response with the remote end opened. The fault resistance increased to 20 ohms after the breaker opened at the remote end. The electromechanical relay operated eventually, but the static relay did not: its operation was still marginal.

The "X" marks the impedance measured by the relay from the bus to the fault. This equals Vc/(Ic(1+K0)) when the remote breaker is open. Here Vc and Ic are the phase C voltage and current, and K0 is the scalar tap setting for zero-sequence compensation: (Z0/Z1-1)/3 = 0.6 (electromechanical relay) or 0.7 (static relay), where Z0 and Z1 are the zero-sequence and positive-sequence line impedances as approximated by relay taps. Hence the apparent fault resistance is 20/1.6=12.5 ohms for the electromechanical relay and 20/1.7=11.8 ohms for the static relay.

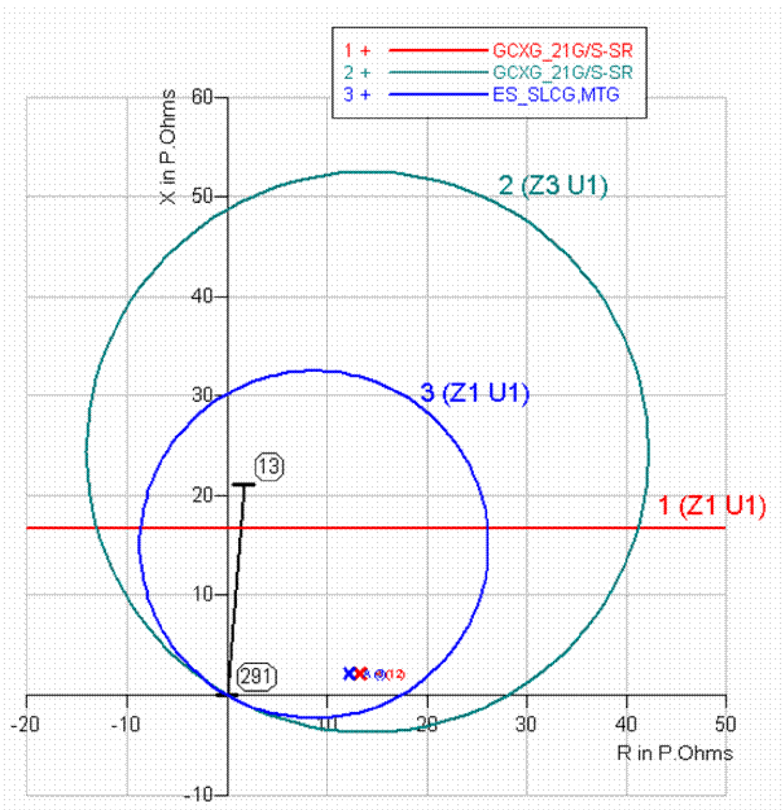

Figure 18 – Relay's Response with Remote End Opened.

7.2 Transient Simulation Testing

Transient simulation testing is defined as "Simultaneously applying fundamental and non-fundamental frequency components of voltage & current that represent power system conditions" [6]. The source of data either comes from captured events via a digital fault record or from EMTP (electromagnetic transient program). Over the years utilities have tried transient simulation testing with mixed results. The major problem many of them face is the failure to correctly create the digital fault record required for testing. The digital fault record presented in figure 7 was corrected, but it still needs to be modified for testing by:

- Converting to Secondary Values
- Adding Prefault Cycles

To convert the scale in a COMTRADE file, the configuration file must be modified. Figure 19 shows the configuration file for the digital fault record in figure 7.

```
EAST SHORE,250
6,6A,0D
1,387VAN C 387 LINE PHASE A-N VOLT,,,KV,  0.439453,0.0,0.0,-2048,2048
2,387VBN A 387 LINE PHASE B-N VOLT,,,KV,  0.439453,0.0,0.0,-2048,2048
3,387VCN B 387 LINE PHASE C-N VOLT,,,KV,  0.439453,0.0,0.0,-2048,2048
4,Rev Ia,,,KA,  0.005525,0.0,0.0,-2048,2048
5,Rev Ib,,,KA,  0.005525,0.0,0.0,-2048,2048
6,Rev Ic,,,KA,  0.005525,0.0,0.0,-2048,2048
60
1
5988.0000,3584
07/22/01,14:34:41.395.900
07/22/01,14:34:41.446.  0
ASCII
```

Figure 19 – Configuration File for Figure 7 COMTRADE File.

Notice the units and "a" factors for the voltage and current channels in the configuration file. The values are:

- Voltage Channels KV 0.430453
- Current Channels KA 0.005525

To convert to secondary values the "a" factors must be multiplied by 1000 and divided by their instrument transformer ratios (PTR and CTR). A new configuration file was created and named "3870722 SEC VOLTAGES AND REV CURRENTS.cfg". The configuration file is shown in figure 20.

```
EAST SHORE,250
6,6A,0D
1,387VAN C 387 LINE PHASE A-N VOLT,,,V,    0.146484333,0.0,0.0,-2048,2048
2,387VBN A 387 LINE PHASE B-N VOLT,,,V,    0.146484333,0.0,0.0,-2048,2048
3,387VCN B 387 LINE PHASE C-N VOLT,,,V,    0.146484333,0.0,0.0,-2048,2048
4,Rev Ia,,,A,    0.013812500,0.0,0.0,-2048,2048
5,Rev Ib,,,A,    0.013812500,0.0,0.0,-2048,2048
6,Rev Ic,,,A,    0.013812500,0.0,0.0,-2048,2048
60
1
5988.0000,3584
07/22/01,14:34:41.395.900
07/22/01,14:34:41.446.0
ASCII
```

Figure 20 – Configuration File for COMTRADE File with Secondary Values.

The data file "3870722 SEC VOLTAGES AND REV CURRENTS.dat" when viewed with the universal viewer is shown in figure 21.

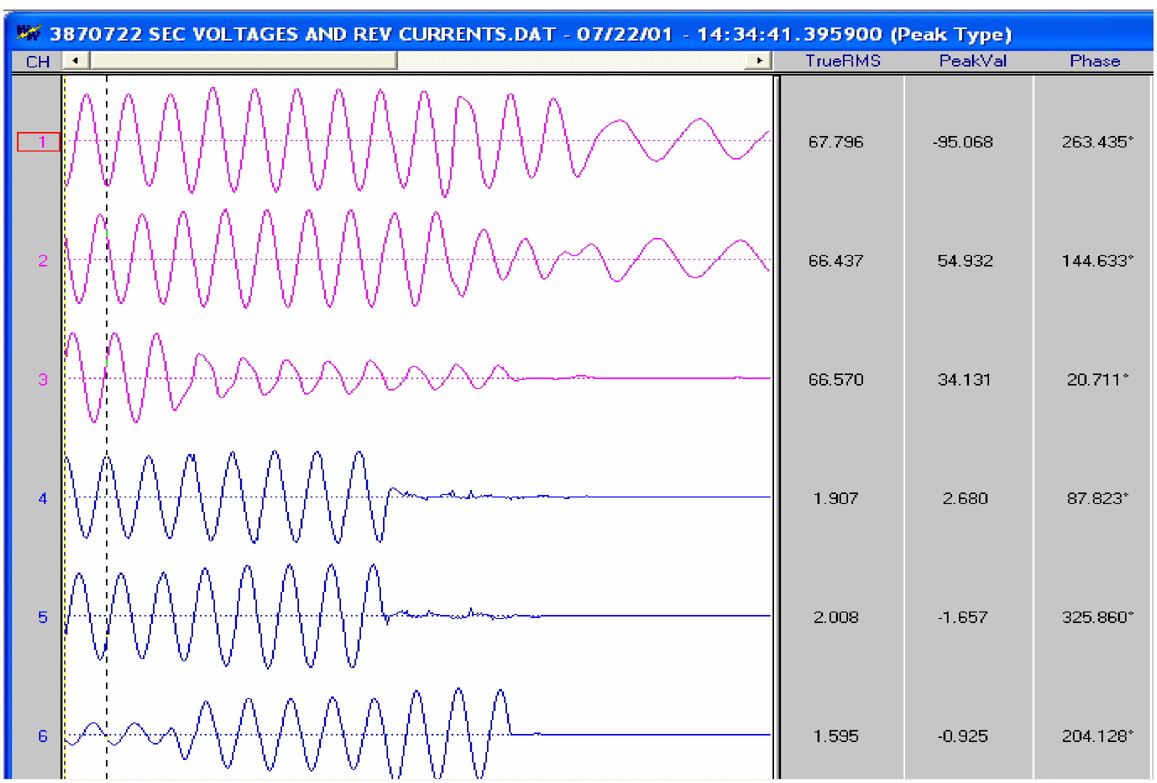

Figure 21 – Data File for COMTRADE File with Secondary Values.

The COMTRADE file with secondary values was imported into software that controls the power system simulator test equipment. Over sixty cycles of prefault waveform was added by copying the first cycle of prefault and duplicating the waveforms 60 times. The 60 cycle prefault time is needed to essentially place the relay in a state it would normally be in before a fault occurs. If the 60 cycle prefault was not included, the tests would be erroneous because of improper memory stored in the relay [13].

Figure 22 shows the transient simulation test waveforms.

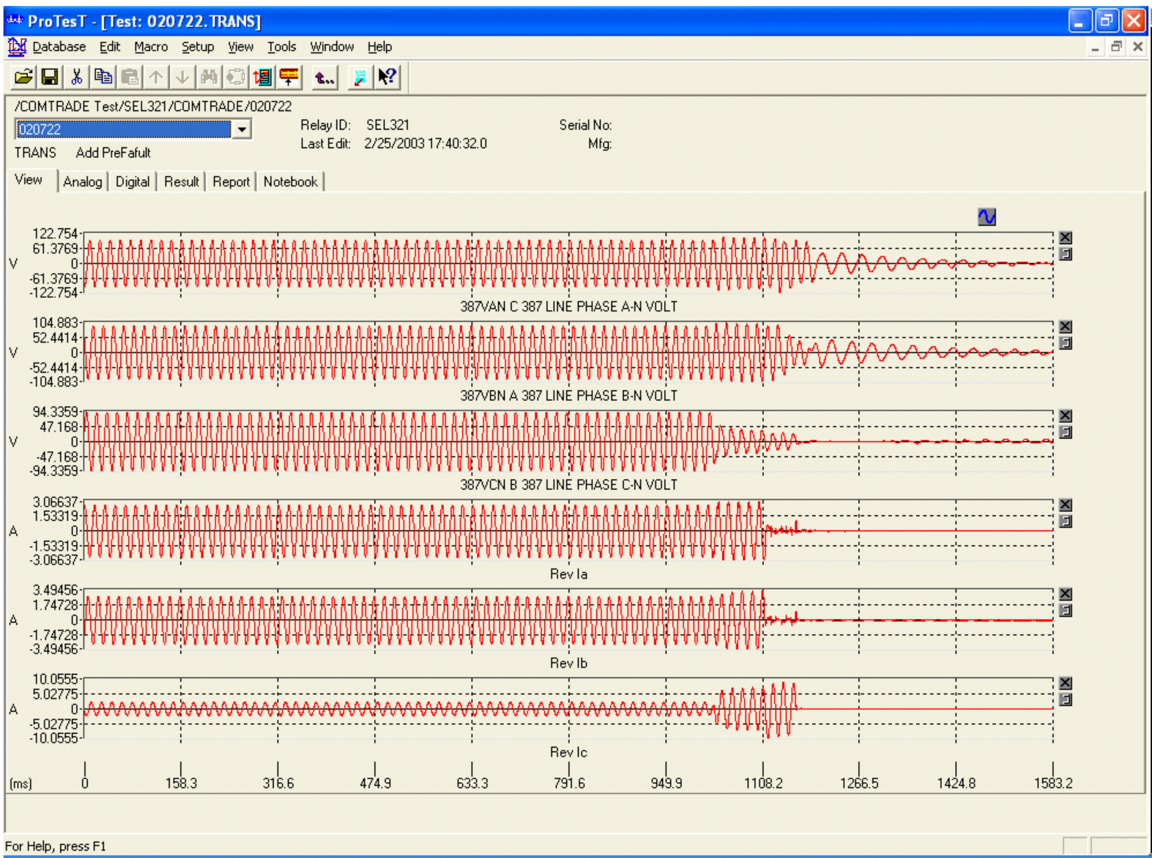

Figure 22 – Transient Simulation Test Waveforms.

7.3 Transient Simulation Testing of a Digital Line Relay

One of the advantages of playback is to test new relays to determine their response to “killer applications”. With today’s software tools and computerized hardware, a utility can play back these difficult applications to ensure that a new relay design will not have the same application problems as previous relay designs may have had.

A digital line relay was tested to determine its response compared to the electromechanical and static relay designs. The relay’s dynamic characteristic was used and its response is presented graphically in figure 23.

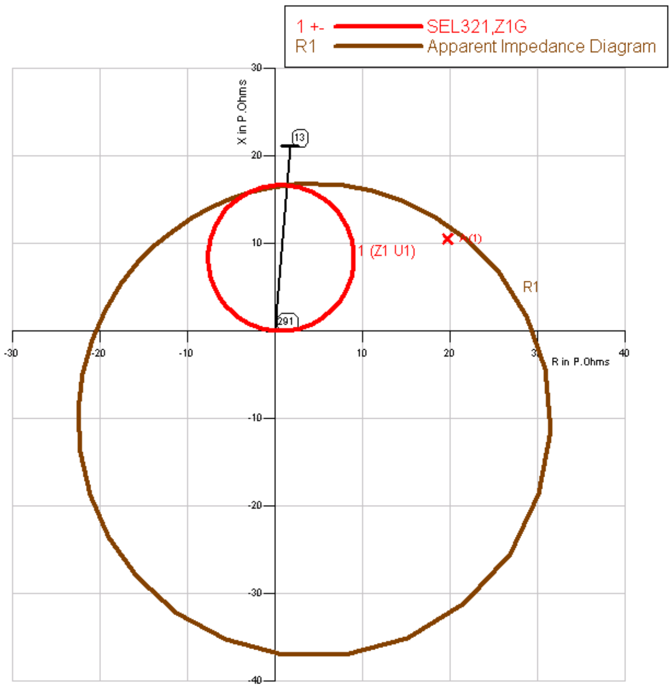

Figure 23 – Digital Line Relay’s Response to the Initial Fault.

Here, zone 1 of a digital line relay was set at 80 percent of the line, and the complex zero-sequence compensation factor (K) was set as (Z0/Z1-1)/3 which equals 0.71 at -22.56 degrees, to match the line. The relay sees the initial fault resistance as 20 ohms because of the remote infeed.

The larger circle shows the "relay view" [4]: the operating limits of phase C apparent impedance, Vc/(Ic + K*3*I0). These limits are computed from the actual operating equations. The circle diameter is approximately the reach setting plus the equivalent source impedance behind the relay. This positive sequence-polarized relay covers higher-resistance faults than those utilizing self-polarized mho elements, for which the diameter of the circle equals the reach setting.

Under a transient simulation test with the fault recording, the relay operated in about 50 ms because the fault plotted just inside its dynamic operating characteristic. The fault location given by the relay under test was 10.8 % from the local end.

8. Summary

The ability to use event recordings to verify protective relay operations is now a reality. Automatic data collection of fault records assures the timely capture of events. The automatic file-naming in a structured format provides the means to search large databases quickly to find the information required for analysis. Software analysis tools that allow the user to read, interpret, modify and convert digital fault files and then store them in formats required for playback are now available.

Selected channels of three-phase voltages and currents can now be easily converted into summary files and played back to relays to correctly evaluate a relay's response to a fault. A relay system simulator provides the calculations and graphical presentation of the relay's response by using detailed phasor models of the relay elements. In addition, the process of creating a COMTRADE file to perform a transient simulation test has been presented.

These techniques were used to analyze, validate and explain the actual relay performance during a high resistance line fault through tree contact on a 345 kV line.

Future research and development objectives include the integration of software that provides automatic data collection, file-naming, waveform analysis and playback into expert systems used to evaluate relay performance. The software will also create the test files required to replay COMTRADE records. The integrated information system will open the path for implementing old dreams of expert system/artificial intelligence concepts.

References

[1] A. & M. Makki, M. Taylor, L. Johnson, and A. T. Giuliante, “Relay Information Management” 28th Annual Western Protective Relay Conference, Spokane, Washington; October 2001.

[2] "IEEE Standard Common Format for Transient Data Exchange (COMTRADE) for Power Systems," IEEE Standard P37.111, 1999, Institute of Electrical and Electronics Engineers, New York, NY

[3] Paul F. McGuire, Donald M. MacGregor, John J. Quada, and Daryl B. Coleman, “A Stepped-Event Technique for Simulating Protection System Response,” presented at 6th Technical Seminar on Protection and Control, Natal, Brazil; September 27 - October 2, 1998.

[4] A. T. Giuliante, S. P. Turner, and J. E. McConnell, “Considerations for the Design and Application of Ground Distance Relays,” 22nd Annual Western Protective Relay Conference, Spokane, Washington; October 1995.

[5] Mark K. Enns and Paul F. McGuire, “Data Base Organization for Protection Engineering,” CIGRE Study Committee 34 Colloquium, Johannesburg, South Africa, October 1-3, 1997.

[6] "Relay Performance Testing," Special Report 96 TP 115-0 for the IEEE Protective Systems Relaying Committee (PSRC), 1996.

[7] A. & M. Makki, and A. T. Giuliante, “Software for Collection and Analysis of Digital Fault Records”, NETA World Magazine, Fall 2001.

[8] "IEEE Guide for Determining Fault Location on AC Transmission and Distribution Lines," IEEE Standard PC37.114, Institute of Electrical and Electronics Engineers, New York, NY; to be published.

[9] S. E. Zocholl, “Three-Phase Circuit Analysis and the Mysterious k0 Factor,” 22nd Annual Western Protective Relay Conference, Spokane, Washington; October 1995.

[10] S.P. Turner, "Simple Techniques for Fault Location," presented at 56th Annual Georgia Tech Protective Relay Conference, Atlanta, Georgia; May 1-3, 2002

[11] Donald M. MacGregor, A. T. Giuliante, Russell W. Patterson, “Automatic Relay Setting,” 56th Annual Georgia Tech Protective Relaying Conference, Atlanta, Georgia; May 1-3, 2002.

[12] George E. Alexander and Joe G. Andrichak, “Ground Distance Relaying: Problems and Principles,” 47th Annual Georgia Tech Protective Relaying Conference, Atlanta, Georgia; April 28-30, 1993.

[13] E. O. Schweitzer III and Jeff Roberts, “Distance Relay Element Design,” 46th Annual Conference for Protective Relay Engineers, Texas A&M University, College Station, Texas; April 12-14, 1993.

A.T. Giuliante is president and founder of ATG Consulting (previously ATG Exodus). Prior to forming his company in 1995, Tony was Executive Vice President of GEC ALSTHOM T&D Inc. - Protection and Control Division, which he started in 1983. From 1967 to 1983, he was employed by General Electric and ASEA. In 1994, Tony was elected a Fellow of IEEE for "contributions to protective relaying education and their analysis in operational environments." He has authored over 40 technical papers and is a frequent lecturer on all aspects of protective relaying, including electromechanical, solid state and digital based equipment. Tony is a past Chairman of the IEEE Power System Relaying Committee 1993-1994, and past Chairman of the Relay Practices Subcommittee. He has degrees of BSEE and MSEE from Drexel University 1967 and 1969.

Donald M. MacGregor is a Lead Engineer at Electrocon International, Inc. He received his B.A. degree with Honors in mathematics in 1970, from St. Catharine's College, Cambridge, England. He next attended University College of North Wales in Bangor, where he earned his Ph.D. in Electronic Engineering in 1973. He joined Electrocon in 1973 and has made significant contributions to software for fault analysis, the modeling of power transformers, and power system protection, including detailed models of multifunction relays.

Amir and Maria Makki are married with three children. In 1991, they created SoftStuf Inc., an automation and process control company based in Philadelphia, PA. Their main trademark is the Wavewin software, a common platform for collection, management and analysis of power system information. Amir, MSEE, is a graduate of Tennessee Technological University, Cookeville, TN and Maria, BSCS, is a graduate of Temple University, Philadelphia, PA. So far, their combined record of professional contributions has included over 20 publications, 5 U.S. Copyrights, and 2 U.S. Patents.

A. P. (Tony) Napikoski is a graduate of Worcester Polytechnic Institute with a Bachelor of Science in Electrical Engineering. He is a member of the IEEE Power Engineering Society and is active in the Power System Relay Committee as a member of the Line Protection Subcommittee and several working groups. He is also a member and past Chairman of the Transient Recorder Users Council. He is a licensed Professional Engineer in the State of Connecticut. He has been a protection and control engineer at The United Illuminating Company since 1981 and is presently the Principal Engineer -Protection and Control.