A GUIDE TO TRANSFORMER DIGITAL FAULT RECORDING EVENT ANALYSIS

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Abstract

Proper interpretation of fault and disturbance data is critical for the reliability and continuous operation of the power system. A correct interpretation gives you valuable insight into the conditions and performance of various power system protective equipment. Analyzing records is not an intuitive process and requires system protection knowledge and experience. Having an understanding of the fundamental guidelines for the event analysis process is imperative for new power engineers to properly evaluate faults. As senior power engineers retire, detailed knowledge of how to decipher fault records has the potential to be lost with them. This paper addresses fundamentals of power system fault analysis and provides the new event analyst with a basic foundation of the requirements and steps to properly analyze and interpret fault disturbances.

Introduction

The analysis of power system faults requires extensive system protection knowledge, and experience. In addition, one also needs to know, in detail, the design characteristics of each power system element and how it behaves under certain power system conditions. When analyzing power transformer faults, a profound understanding of transformer protection schemes, relay setting principles and transformer design characteristics is necessary in order to properly analyze transformer faults. Once the relay engineer has acquired extensive experience in these fields, the analysis process becomes simpler. One can find out that there is only one way to apply and connect a differential scheme correctly, but there are many different ways to apply and connect them incorrectly. Avoiding these mistakes is a manner of experience, requiring familiarity with classic errors. Since the analysis of power transformer faults is a broad subject, it is the intention of this paper to introduce the new system analyst with transformer fault real case study.

Purpose of Fault Recording

Fault records are one of the most important pieces of evidence that event analysts can have during system event investigations. They can provide the reasons for premature equipment failure, supply waveforms and status of equipment behavior during an event, and give necessary information to perform post-fault event analysis. Proper use and interpretation of event records can lead to corrective action for a given system problem resulting in improved performance and reliability of any generation, transmission, and distribution system. Fault records are now captured by microprocessor relays but records are limited to sampling rate and record length. Some use digital filters that do not reflect the real captured waveform (1). Digital fault recorders offer specialized, specific, and dedicated microprocessor equipment with far superior sampling rates, record lengths, and unfiltered recording abilities. Utility engineers have to make balanced decisions as to what equipment is better to use for pre- and post-event analysis. Regardless of the equipment employed, both come at some economic cost. Nevertheless, as expected maximum use of their recording capabilities assures maximum return in their investment.

Fault recording has been used for decades now, generally for two main purposes:

- Recording of system events
- Monitoring of system protection performance

Recording of System Events

Recording of system events can be classified as fast transient recordings and slow swing recordings.

- Relays and recorders are capable of recording fast system events such as power system faults, lightning strikes, switching events, insulator flashing, etc. These types of transient events are usually short-lived and fast; therefore, they do not require long record lengths unless faults have cascaded into multiple system elements or a fault has remained in the system longer than normal. In these cases longer transient records are needed to capture the entire event. These types of records let the analyst know the current and voltage magnitudes, time, and duration that were observed during the course of the event. This information can then be analyzed and dissected to look for potential problems in the timing as well as current and voltage magnitudes. Analysts can detect abnormalities such as current transformer saturation, breaker restrikes, ferroresonance, CCVT transients, etc. Investigation of current magnitudes can also be used to determine the deviation of actual fault values vs. calculated values from software. Short circuit databases, due to their large composition, can contain errors that yield misleading fault values. Comparing actual and calculated values is a good practice to check for possible inconsistencies. Transient records can further improve the analysis of such events by providing the symmetrical component quantities of the current and voltage during steady state and fault conditions. The positive, negative, and zero sequence components can be used to determine their individual magnitudes during the transient event. They can also be used to verify the type of fault. This process is further expanded in the section below about deciphering power system faults. Another type of system event is incipient faults such as early signs of insulator failure. Such conditions require longer record lengths to capture the early development of the event and are better handled by DFRs because of their record length capabilities.

- Slow swing recordings are designed to capture the power system's response in RMS values following a power swing or disturbance. These records can usually help to determine how well the system is designed. These types of records can capture the response of generators, power swings on transmission lines, load variations caused by voltage and frequency fluctuations, and transient phase angle changes (2). Since these records measure system response, swing recorders are required in specific spots and under different owners of an interconnected system. Swing records do not have the fast rise or sharp current changes that transient records have, since they are sampled at very slow rates. Therefore, accurate time stamps are needed to analyze system event records from many pieces of recording equipment. The records themselves need to cover a much longer period than transient records. There are some microprocessor relays capable of swing recording data, but they are limited by record length. DFRs have swing recording as part of their design and can capture incredibly long records. It is recommended to use maximum record length.

Monitoring Power System Performance

Fault recording devices have proven to be invaluable assets in identifying proper as well as improper behavior of system protection schemes and associated equipment. The ability to record protection system performance such as relays, circuit breakers, and control systems has resulted in design improvements and corrections of the power system. Consequently, companies have prevented future equipment damage and failure, generating economic savings and improving the overall performance of the power system.

Some practical applications of the fault recording devices include monitoring the "failure of a relay system to operate as intended, incorrect tripping of terminals for external fault zones, determination of the optimum line reclose delay, impending failure of fault interrupting devices and insulation systems (2)." Another application is to monitor trip coil energization. Monitoring of trip surges is far superior to monitoring breaker auxiliary contacts. Monitoring the coil energization tells precisely when the breaker command was received. The coil is de-energized by a 52a contact, indicating the precise time when the contact motion began, which can sometimes be quite long. This data can be combined with the line current information revealing when the last breaker interrupted the current, though not the first. Other record events that help to monitor the credibility of a protection system include: lockout relays, transfer trip keys, and receipts. The advantages of trip coil and transfer trip monitoring are expanded in the sequence of events section below.

Triggering of records should be sensitive enough to capture all local faults independent of relay response. Most importantly, the goal is to trigger for many events without resulting in local tripping so power system response can be reviewed. Secondly, it is important to capture a record of a local fault accompanied by a relay failure. Fault recorders have an advantage over recording relays in this regard.

Monitoring circulating zero sequence currents (Io) in autotransformers is very useful since they capture all local and most remote ground faults. Triggering for under-voltage conditions during voltage depressions is also advantageous. A wide variety of local and remote faults can be captured since faults will tend to depress or collapse the voltage. Also, complex line relaying schemes with weak feed provisions can mis-operate on these voltage depressions, so it is good to capture them. A combination of under-voltage and zero sequence current triggers will capture almost all faults near the recording equipment.

Sometimes initial triggering setup does not capture problems associated with mis-operating systems. This is particularly true when the protective scheme operates during non-fault events. Changing the sensitivity of the triggering and adding specific events such as high speed current relays or surge trip detectors can enable the identification of a particular cause or at least capture useful clues. Portable recording units can certainly be used as another tool to identify incipient faults because of their flexibly and mobility.

Many people have questioned the value of digital fault recorders in an era of digital relays with recording capabilities. Nevertheless, digital fault recorders offer far advanced recording capabilities which results in better analysis of system problems and economic savings. Advantages of fault recorders include:

- They are independent of a failed or partially failed relay that a DFR maybe monitoring.
- They do not filter analog signals as many digital relays do.
- They offer more memory capacity, enabling longer records.
- They have faster sampling rates.
- They have broader frequency response.
- They are designed with more triggering options.
- They can monitor many power system components simultaneously.
- They can be used to monitor power quality issues, especially with connections with windfarms, FACTS, static VAR generators, arc furnaces, and variable frequency drives.
- They are useful in studying problems associated with current inrush where large autotransformers are applied in parallel combinations.
- They offer a wide spectrum of system responses during faults.

Once a new engineer has sufficient experience with relay design and the behavior of power transformers, analysis of power transformers is best done by hands-on examination of real events.

Transformer Fault Analysis

The best analysis is often completed as a team (preferably an experience analyst working together with a young analyst, so that knowledge can be passed along). There are many ways to analyze faults and engineers approach the analysis differently. A new event analyst can probably benefit by creating an outline (sample shown below) to keep work on track with the final goal.

Transformer Protection System Performance:

- Review System Design
- Extract Relay Settings
  - Overcurrent Settings
  - Differential Settings
- Fault Behavior
- Fault Magnitudes and Equipment Performance
- Recommendations

External Fault on the Tertiary of an Auto-Transformer

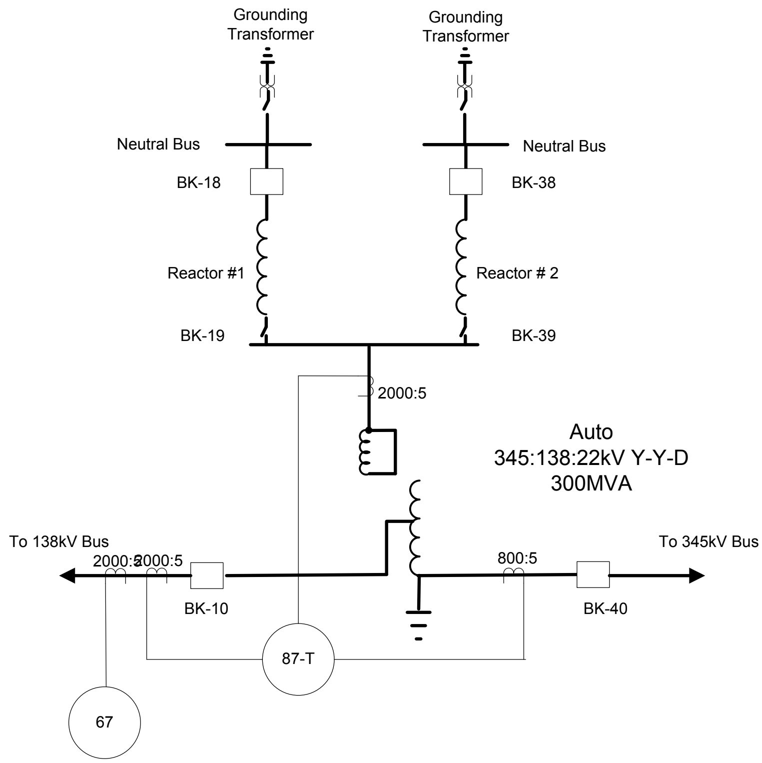

Figure 1: System Oneline

Figure 1 shows a system one line of a 300MVA transformer that interconnects 345kV and 138kV systems. The transformer voltage ratings are 345:138:22kV Wye-Wye-Delta. The delta section of the autotransformer is connected to two reactors that are used to control the voltage levels of the substation buses. For this event, a crew personal isolated the grounding transformer switch for reactor number one. The grounding transformer was connected between the neutral bus of the reactor and ground. A few minutes later, the technician opened the switch for the grounding transformer for reactor number two. At that instant, the lightning arresters in the tertiary of the transformer failed and relays protecting the transformer issued a trip. This is what is known about the fault event. We need to find out what caused the lightning arrestors to fail.

At this point, a protection engineer becomes a detective and starts looking for clues that can help reveal what might have caused the failures. It is recommended that drawings, records from relay and digital fault recorders, eyewitness accounts, relay settings and any other information related to the fault be collected. This information will provide invaluable clues that will help determine the cause of failure. For this event, we will follow the outline above in order have a path that can uncover possible issues with design.

Relay Setting Extraction: For this case, we have extracted the settings from a differential and overcurrent settings from a transformer differential microprocessor relay. The settings are shown in Table 1.

```
Current Transformer Data
CTRS    := 160      CTCONS  := Y        CTRT    := 400      CTCONT  := Y
CTRU    := 400      CTCONU  := Y
Potential Transformer Data
PTRV    := 700      PTCONV  := Y        PTCOMPV := 0.00     VNOMV   := 197
Voltage Reference Terminal Selection
VREFS   := OFF      VREFT   := OFF      VREFU   := V
Differential Element Configuration and Data
E87TS   := 1
E87TT   := 1
E87TU   := 1
ICOM    := Y        TSCTC   := 11       TTCTC   := 0        TUCTC   := 11
MVA     := 300      VTERMS  := 345.00   VTERMT  := 22.00    VTERMU  := 138.00
TAPS    := 3.14     TAPT    := 19.68    TAPU    := 3.14     O87P    := 2.00
SLP1    := 35.00    SLP2    := 70.00    U87P    := 16.00    DIOPR   := 1.20
DIRTR   := 1.20     E87HB   := N        E87HR   := Y        PCT2    := 15
PCT4    := 15       PCT5    := 35       TH5P    := OFF      87QP    := 0.10
SLPQ1   := 10       87QD    := 5.000
```

Winding S Overcurrent Elements Terminal S
E50S := P
Terminal S Level 1
50SP1P:= 93.00
CTR=160:1 Primary Amps = 93*160=14880 Amps
67SP1TC := 1
67SP1D := 8.00
Terminal S Level 2
50SP2P := OFF

Winding U Overcurrent Elements Terminal U
E50U:= P E67U:= N
Terminal U Level 1
50UP1P := 57.12
CTR=400:1, Primary Amps = 400*57.12 = 22848 Amps
67UP1TC := 1
67UP1D := 8.00
Terminal U Level 2
50UP2P := OFF

Winding T Overcurrent Elements Terminal T
E50T := P,Q
Terminal T Level 1
50TP1P := 30.00
CTR=400:1, Primary Amps = 400*30 = 12000 Amps
67TP1TC := 1
67TP1D := 8.00
Terminal T Level 2
50TP2P := OFF
Terminal T Neg-Seq Level 1
50TQ1P := 22.50
CTR=400:1, Primary Amps = 400*22.50 = 9000Amps
67TQ1TC := TF32Q
67TQ1D := 8.00
Terminal T Neg-Seq Level 2
50TQ2P := OFF

The relay setting extraction uncovers the active settings (and the trigger levels such settings are supposed to issue a command). For the differential settings, it is a good idea to review the tap, the minimum operate current (IOmin) per unit values, the slope percentages, the high differential setting (IU), harmonic restraint and blocking settings. If IOmin settings accounted for CT error, transformer load tap changers or light through faults, then paperwork should exist to indicate why such trip levels were selected. Slope 1 and 2 percentage settings are usually based very closely on through faults where CT saturation can pose a problem to the differential algorithm. A report should be available that justifies such setting selection. If no report is selected, then proper studies and simulations should be performed in order to come up with the correct settings.

The overcurrent settings are usually selected based on a fault study that determines the minimum and maximum fault current levels. The trip levels depend on the philosophy of the company. When performing fault forensic analysis for over-currents, it is a good idea to convert all setting values to primary values so that they can easily be superimposed with the faulted waveform.

Once the relay settings have been examined and settings errors have been eliminated as possible causes for the transformer failure, it is time to look at the waveforms. At this point, all the records from DFRs and relays should be collected and shown in a single graphical screen as shown in **Figure 2**. This figure contains the relay waveforms that captured the fault. The first two traces are the 138kV current and voltages which indicated the fault inception. These two traces were captured by the overcurrent microprocessor relay, located at breaker 10. The rest of the currents in Figure 2 were captured by the transformer differential relay. Let's take a look at the overcurrent and differential settings performance.

<u>Overcurrent Setting Performance:</u> The relay settings indicate that each winding of the differential relay has a 67 direction elements. The high side 67 element picks up at 14880 primary amps, with a time delay of 8 cycles. The low side of the transformer picks up at 22842 amps, with a time delay of 8 cycles. The tertiary 67 element picks up at 22000 primary amps, with a time delay of 8 cycles.

For this event, the primary and secondary elements did not pick up since the fault current values are below the tripping settings. However, the 67 element of the tertiary did pick up since the tertiary was exposed to a fault value close to 40000 amps. Unfortunately, the differential relay did not provide enough pre-fault cycle data where we could have observed the inception of the fault in the tertiary side of the transformer. However, the microprocessor overcurrent relay located in breaker 10 did provide the voltage and current traces for the inception of the fault. It can also be observed that the tertiary 67 element cleared the fault before the 87T element.

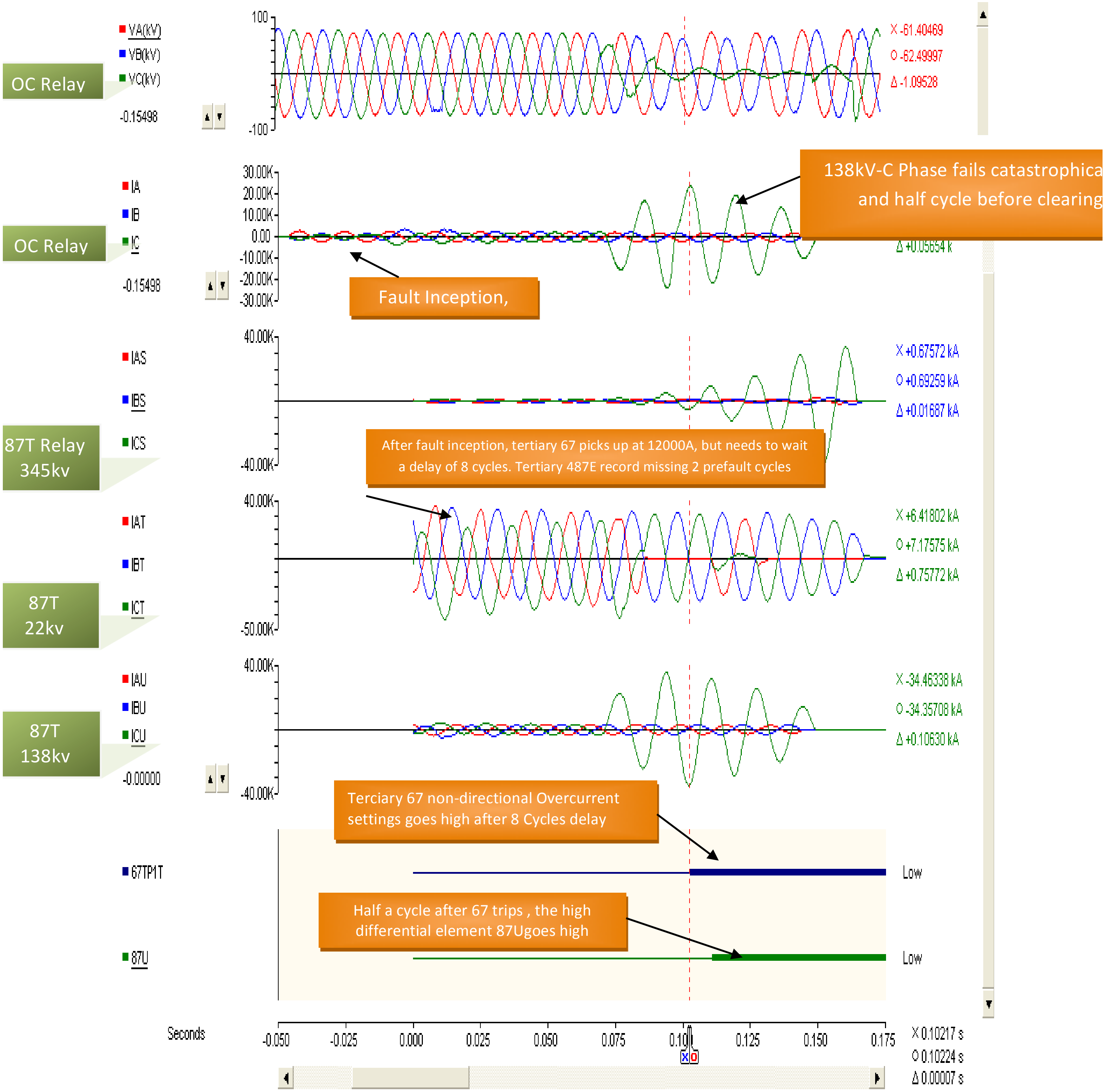

Figure 2: Sequence of Events

Transformer Differential Performance: The through fault seen by the 300MVA transformer is shown in **Figure 3**. An easy way to determine whether or not the fault is external to the transformer zone of protection is to overlay the currents from the same phase, as shown in Figure 3. As can be observed, the high side current IAS and low side currents IAU were feeding the tertiary current IAT. This is verified by looking at the traces as IAS and IAU are 180 degrees apart from IAT. An internal fault developed 1 cycle before the non-directional 67 element asserted. Half a cycle after the 67 operation, the high differential settings 87U of 16 p.u. current asserted and issued a trip. The 87U setting is similar to an instantaneous overcurrent setting where it does not need a time delay to operate. Similarly, the 87U does not need any restraint current to operate. Once the current reached a value of 16 p.u, the 87U setting was asserted.

The AutoT2 IAC residual current, which is the fourth trace on **Figure 3,** was captured by the TESLA 3000 DFR. This current monitored the Delta circulating currents in the tertiary and indicated that the internal fault started developing two cycles before the 87U trip. The internal fault probably developed in the tertiary bushings of the transformer which is internal to the 87T zone of protection. This time period seems to be quite long, possibly due to the high IOP differential settings of IOP = 2.0 p.u, where the operating current (IO) and restraint currents (IR) need to be quite high in order to get into the operating region. The IO and IR current behavior is shown in **Figure 4**. For a differential element to operate, the IO needs to be above the IR current. It can be seen that IO current never surpassed the IR current throughout the process. However, since the IO value reached the 87U (high value operate setting of 16 p.u.), the function asserted, regardless of the restraint current.

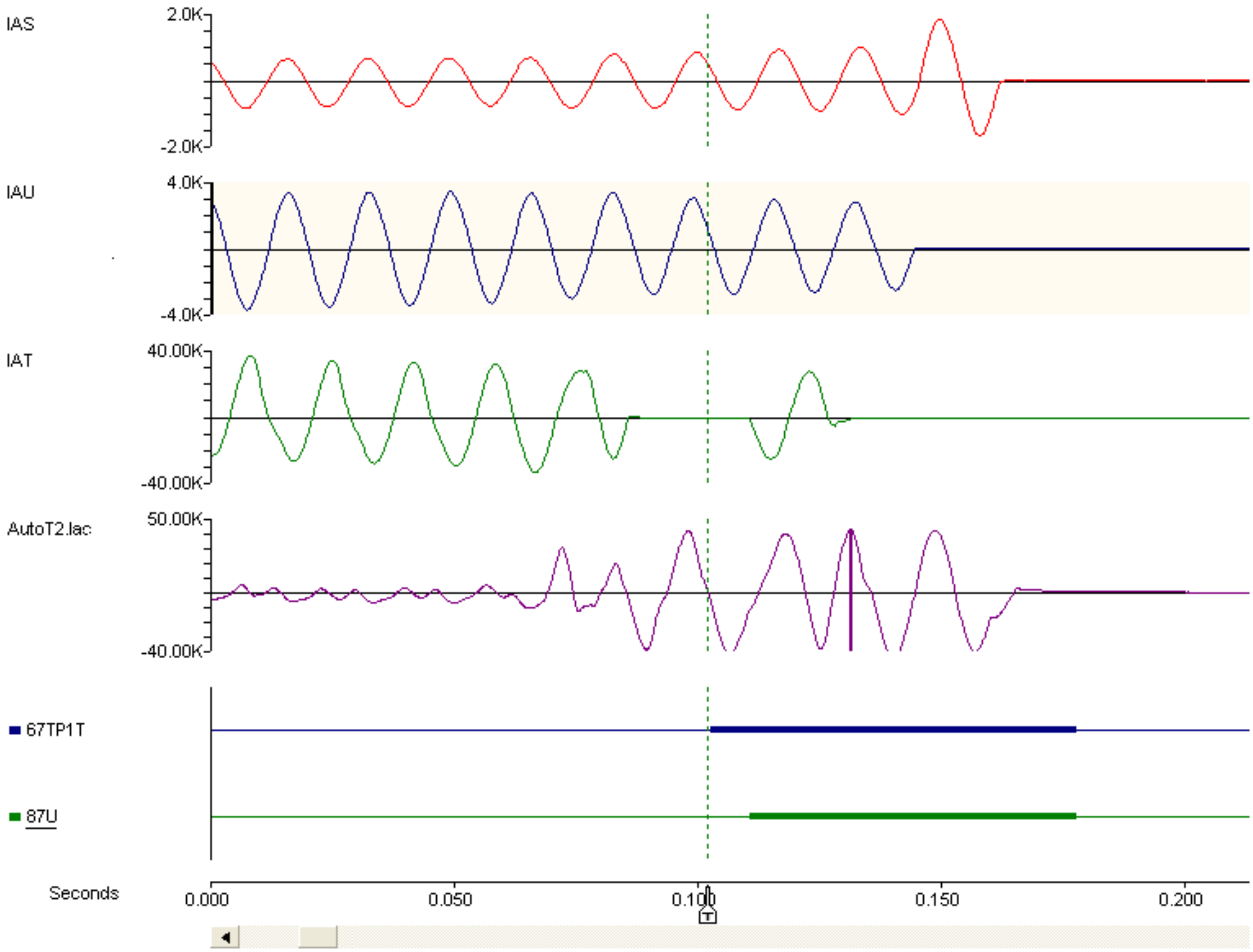

Figure 3: 87U Differential Operation

The IOP should be set as sensitive as possible to detect internal faults. The phase differential settings 87B of most protective relays are not as fast as 87N residual or 87Q negative sequence differential functions would be. Common practice is to set 87B to be as sensitive as possible since it is inherently slower. In addition, study CT saturation, transformer load variations and lead burdens, to determine how sensitive the differential functions can be set in order to avoid tripping during external faults.

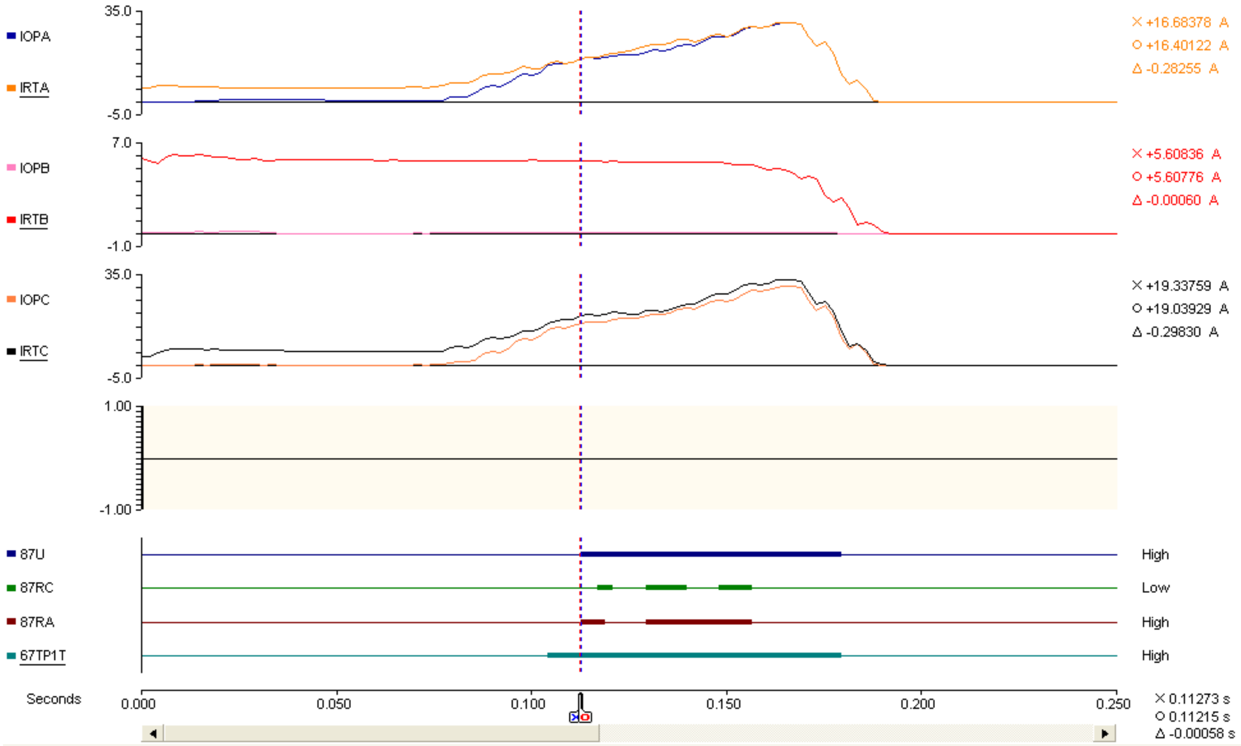

Figure 4: Operate and Restrain Currents

Fault Behavior and Lightning Arresters

At this point, we should look out for current and voltage behavior other than high current magnitudes or low voltage magnitudes due to the fault. We are essentially looking for CT saturation, high DC offset or noisy signals that might contain high or low frequencies, transformer over-excitation or any other data with clues about what happened during this fault. By taking a closer look at the 138kV current traces (second trace) in **Figure 2**, we can determine that the overall fault initiated as a phase-to-phase fault between A-B phases. This unsymmetrical fault is verified by looking at the positive, negative and zero sequence components, as shown in **Figure 5**. The value for A-phase is twice as much as B and C phases. A and B Phases are 180 degrees apart. By analyzing the symmetrical component values, we can see the presence of positive and negative sequence values, which validates that the fault is a phase to phase fault. However, three cycles after the fault inception, the unsymmetrical fault evolved into a symmetrical three phase fault. The three phase fault is verified by the presence of only positive sequence currents, as seen in **Figure 6**.

As a result, the records indicate that the fault began as an unsymmetrical fault and evolved to a three phase fault in the tertiary load side of the transformer. According to field personnel, the fault began after the grounding transformer switch of the second reactor was opened. Note that the first reactor grounding switch had been opened a few minutes before with no problems.

Assuming the reactors were still connected to the transformer tertiary, when the second grounding switch was opened, the stored energy of the first and second reactors tried to discharge back to the system and to ground. The three phase symmetrical fault provides evidence that such a hypothesis can be validated. The amount of energy discharged to ground through the lightning arresters reached a critical limit until they failed. **Figure 7** shows the current behavior captured by the differential relay and tells an overall view of the fault's progress. **Figure 8** shows a more detailed view of the fault. We can observe that the IAT current went to zero. At this moment, the IAT lightning arrester failed and such energy does not go to ground but it goes to ICU or the 138kV C Phase since this current increases to over 100A. This could be due a flash over from the tertiary A-Phase to the secondary A-Phase. The transfer of energy produced a catastrophic fault resulting in ICU lightning arrested failing. It can also be seen that the 138kV breaker opened first by observing the IAU, IBU and ICU currents go down to zero, and then the 345kV opened later. There isn't a digital input that can tell us why one breaker opened first. This could have been proven by looking at the trip coil energization times, but such inputs were in the 345kV recorder which did not capture the fault.

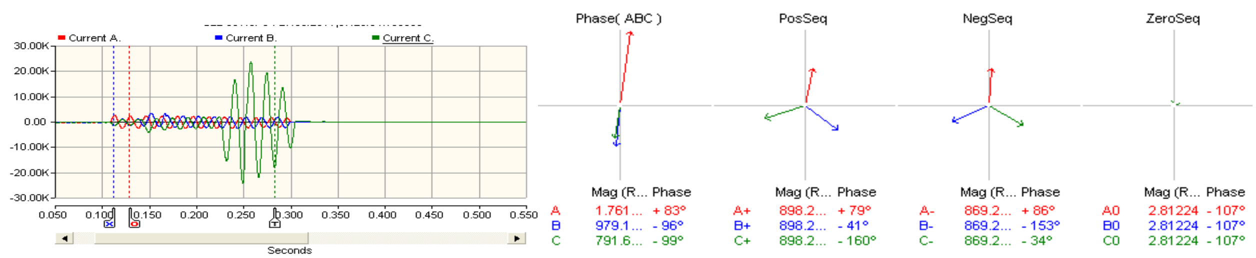

Figure 5: Phase-to-Phase Fault during Inception of Fault

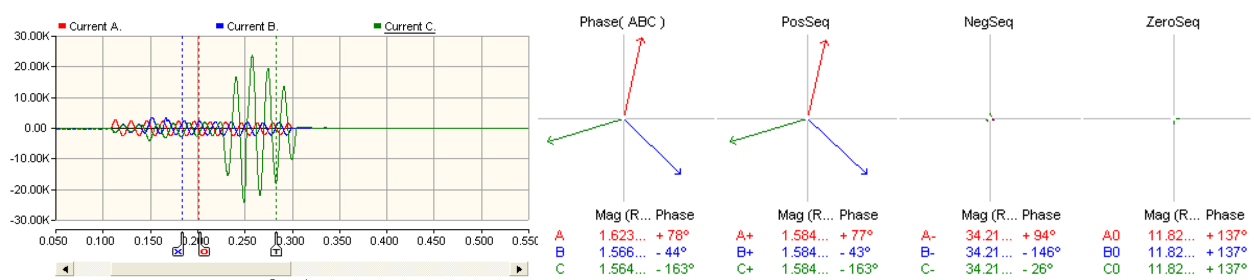

Figure 6: Phase-to-Phase Fault during Inception of Fault

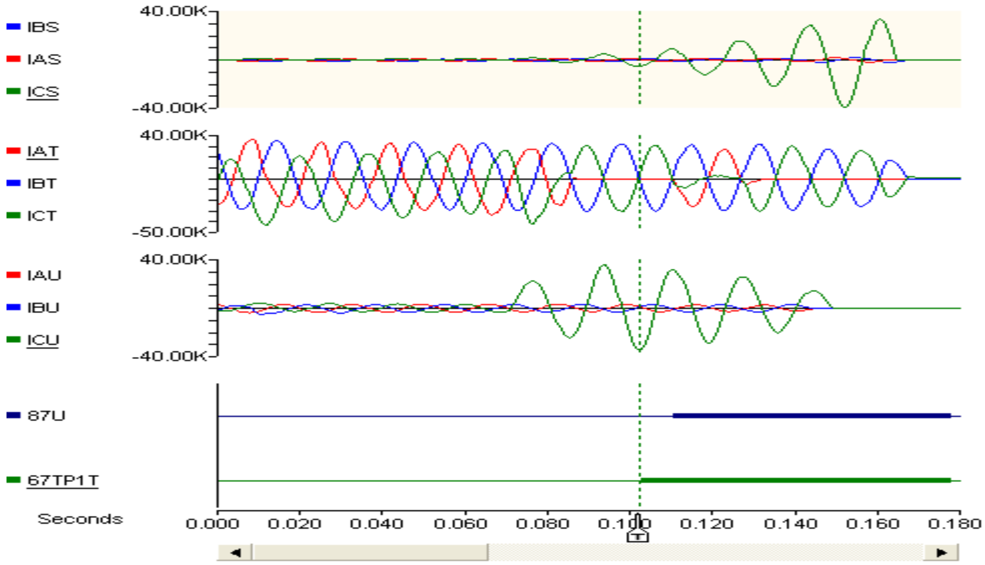

Figure 7: Differential Relay Operation

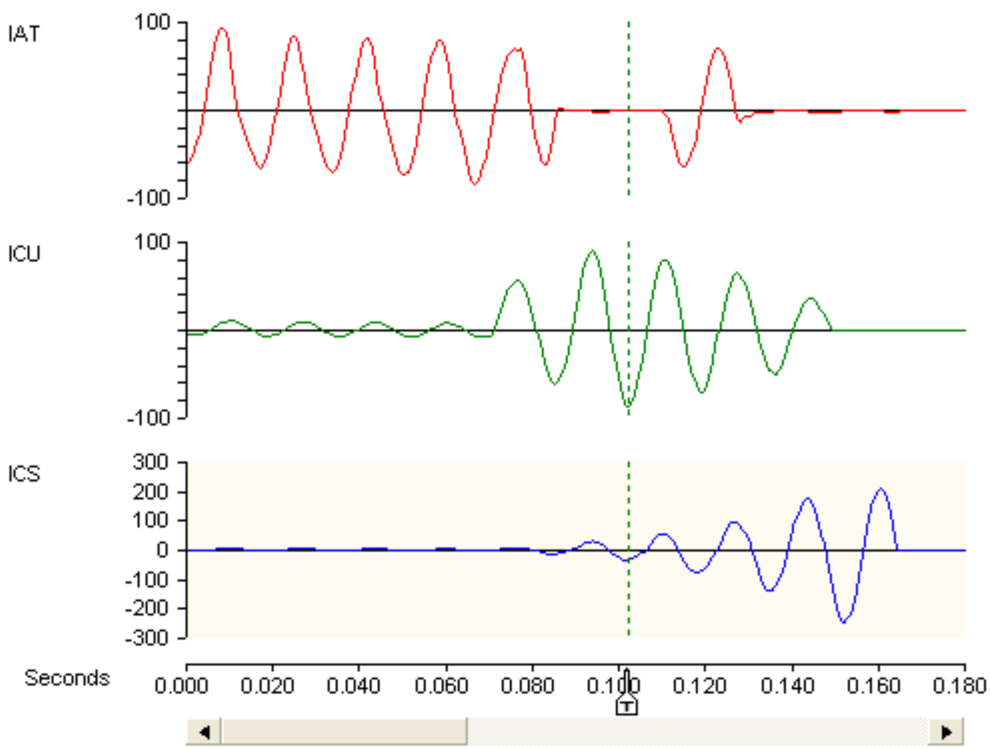

Figure 8: Fault Energy Transfer from Tertiary IAT to Secondary ICU

Fault Magnitudes and Equipment Performance

The TESLA record and unfiltered data record of the microprocessor differential relay captured oscillographic current magnitudes that go beyond equipment design capabilities. **Table 1** shows the maximum current magnitude seen by the differential relay. It is clear that the high side C-phase current experienced an incredible secondary current of 240 amps. See **Figure 9**. Note that there is no evidence that the CT saturated at such a high current. Similarly, the tertiary C phase current experienced about 105 secondary amps. Some of the other current transformers also experienced high magnitude currents close to maximum design capabilities. See **Table 1**.

If relay design settings allow for the use of higher CT ratios, it is recommended that higher CT ratios be used. Relay protection schemes should be designed based on the maximum fault current available at CT location and should be below 100 amps for the maximum fault. However, fault data cases might not accurately demonstrate high fault currents due to bad case data. This would be a good opportunity to compare fault data information from the cases versus real data. In addition, due to the amount of secondary current that the differential relay was exposed to, the manufacture should be consulted to verify the reliability of the unit. There is also a presence of DC offset from the system, but it did not play a major role in the operation of the relay.

Table 1. Fault Current Magnitudes

Data	Ratio	Primary Amps	Secondary Amps	Below 20 times normal or 100 amps
345kV CT A Phase	160:1	1800	11.25	Yes
345kV CT B Phase	160:1	2000	12.5	Yes
345kV CT C Phase	160:1	39000	243.75	No! 40 times normal
138kV CT A Phase	400:1	3500	8.75	Yes
138kV CT B Phase	400:1	4800	12	Yes
138kV CT B Phase	400:1	36000	90	Yes
22kV CT A Phase	400:1	37000	92.7	Yes
22kV CT A Phase	400:1	36000	90.0	Yes
22kV CT A Phase	400:1	42000	105	No

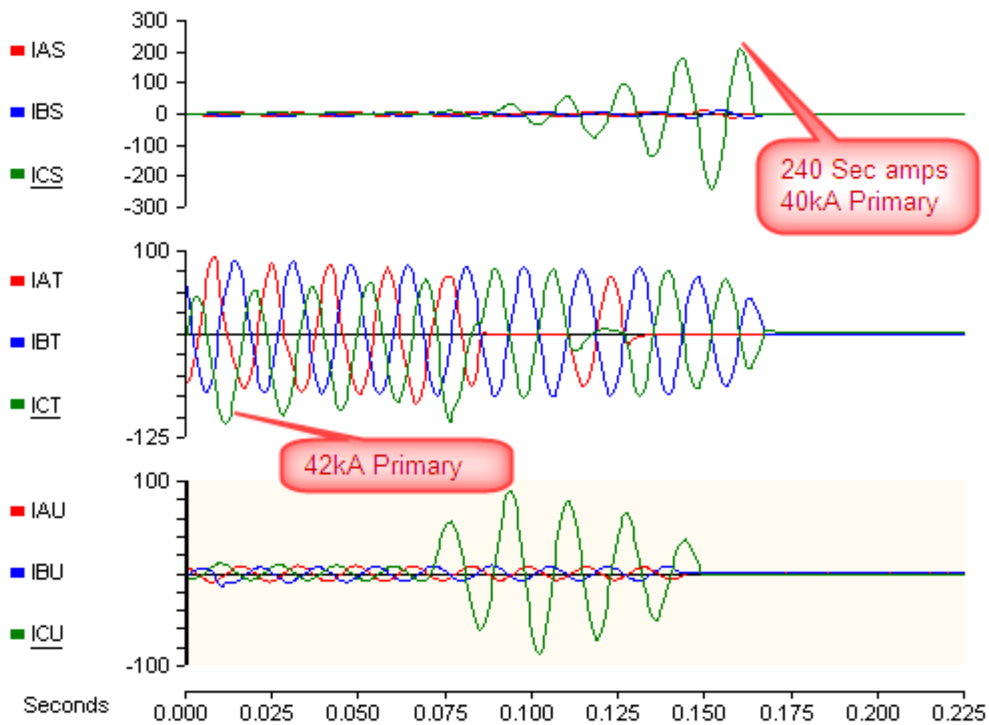

Figure 9: Current Magnitudes Beyond 100 Secondary Amps

Conclusions

This transformer analysis exercise has demonstrated one of many ways to analyze transformer faults. The new event analyst is recommended to follow the outline shown in this paper to prepare him/her for future analysis. As more experience is acquired, each individual can develop his/her own method of transformer analysis. However, the method shown in this paper provides a good foundation for new engineers and analysts.

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Biography

Joe Perez is the owner of SynchroGrid LLC. Previously, he worked as Application Engineer for the relay and digital fault recorder products of ERLPhase Power Technologies, formerly NxtPhase T&D. He previously worked as a transmission engineer and a field application engineer, gaining experience in system protection projects and transmission system studies, including fault, power flow, and contingency analysis. Joe graduated from Texas A&M University in 2003 with a BSEE and has previously presented papers at WPRC, Texas A&M and Georgia Tech Relay Conferences. Joe is a registered professional engineer in the state of Texas and a member of PSRC, IEES, and PES. Joe resides in the Bryan/College Station area. He can be contacted at jperez@synchrogrid.com.

Cesar Rincon is the Lead Engineer (Relay Settings) for the areas of LA and TX in the Entergy service territory. He has worked in relay protection for the full range of power systems devices, including relay testing, acceptance testing and commissioning. His work also includes short circuit modeling and real time modeling/simulation. Cesar graduated from the University of New Orleans with a BSEE in 2005 and from Louisiana State University with an MSEE in 2008. He is registered in the state of LA and an active member of the IEEE.