Improve Your Protection Quality By Mining Historical Microprocessor Relay Data

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INTRODUCTION

Excessive amounts of power system data are available from microprocessor-based relays. Data mining techniques extract relevant information from relay events. Improve your protection quality by analyzing this information.

Available Data

Microprocessor-based relays provide large amounts of data about power system operations. This analysis covers 13 years of historical data for a portion of the Pacific Gas & Electric Company (PG&E) transmission system.

Several useful measurements are available from the relay event reports including power system parameters, symmetrical components, relay algorithm output, and other data for statistical analysis.

Results of Mining Data

The presented results can benefit other utilities as well as relay manufacturers.

Utilities have guidelines for determining appropriate relay settings for protecting their transmission lines. These guidelines are based on system model calculations, practical experience, empirical data, assumptions, engineering judgment, and company philosophies regarding risk. Results of mining relay data can be used for reaffirming setting guidelines or making changes to those guidelines.

Method of Data Analysis

The analysis process described is useful for historical data (data stored over a long time period) and for post fault data analysis immediately after an event is generated and stored.

The process of analysis is the following:

1. Store the relay event files.
2. Sort the relay event files into files of similar formatting.
3. Copy and paste the event data into a pre-determined analysis spreadsheet.
4. Consolidate the results for the desired report.

BACKGROUND

For the past thirteen years the northern protection group of PG&E has archived microprocessor-based relay event files that were downloaded for operational analysis or for providing fault locations to field personnel. These events cover only a portion of the PG&E 60, 115, and 230 kV transmission lines. Additional events also include 12 KV, 21 KV and 500 KV lines. These files include 17,020 detailed event files.

This paper presents the analysis and statistical reports of these relay operations. PG&E plans to use the results to make recommendations to influence or confirm protection guidelines and improve protection quality.

To maximize the benefit of analyzing the data, the process must provide the following:

- Flexibility to work with multiple relays/manufacturers
- Reduced event analysis labor
- Algorithm modification access for the user

This paper provides an analysis of the PG&E supplied event reports. The same process applies to any text based data file including those in a COMTRADE format. The process uses a developed software product to sort files on the computer, but Microsoft® Excel is used to perform the analysis. This approach allows a user to easily change the algorithms to fit their needs without requiring a software vendor to make changes.

PG&E Transmission System

The PG&E transmission system serves northern and central California. Table 1 shows a breakdown of the miles of transmission lines and the general construction for each voltage.

Table 1: Complete PG&E Transmission System

Voltage	Steel Construction	Wood Construction	Underground Construction	Circuit Miles
60/70 kV	6%	94%	<1%	5,500
115 kV	58%	40%	2%	6,000
230 kV	97%	2%	1%	5,300
500 kV	100%	0%	0%	1,300

The analyzed events are from the northern portion of the PG&E service territory. This includes a very diverse geography and terrain. Transmission lines traverse beaches, salt marshes, coastal mountains and valleys, the northern Sacramento Valley, and the northern Sierra Nevada Mountains. Different types of construction and configurations are used and different grounding conditions are encountered. The lines are generally medium to long in length. All transmission lines are 3 wire systems. Static wires are occasionally used on 230 KV lines and segmented static wires are utilized on 500 KV lines. Tapped zero sequence in-feeds are very common on lower voltage transmission lines at PG&E.

Protection Quality

Protection quality is the measure of performance of the protection system. This includes many components of the power system including but not limited to potential and current transformers, relays, the DC system, and breakers. The traditional method for measuring protection quality is to test the system one component at a time, in some cases (staged fault testing) the entire system at once, or something in between. In the last few years satellite synchronized end to end testing has been used on high-speed protection schemes.

With microprocessor-based relays, additional data for assessing the protection quality is available every time a relay triggers an event. These events may be for faults occurring out-of-section, for faults in the protected section, or for other system disturbances such as a power system swing condition.

AVAILABLE DATA

PG&E first started using microprocessor-based relays on the transmission system in 1986. An increasing number of relays were installed each year after that. Starting in 1989 these relays were accessed with a dial-up modem on a monthly basis. That schedule was only followed for a few years as the number of relays quickly grew. Since then the relays have only been queried by dial up modem to review operations and to provide fault locations. Approximately 200 to 300 fault locations are provided each year to the PG&E transmission line department.
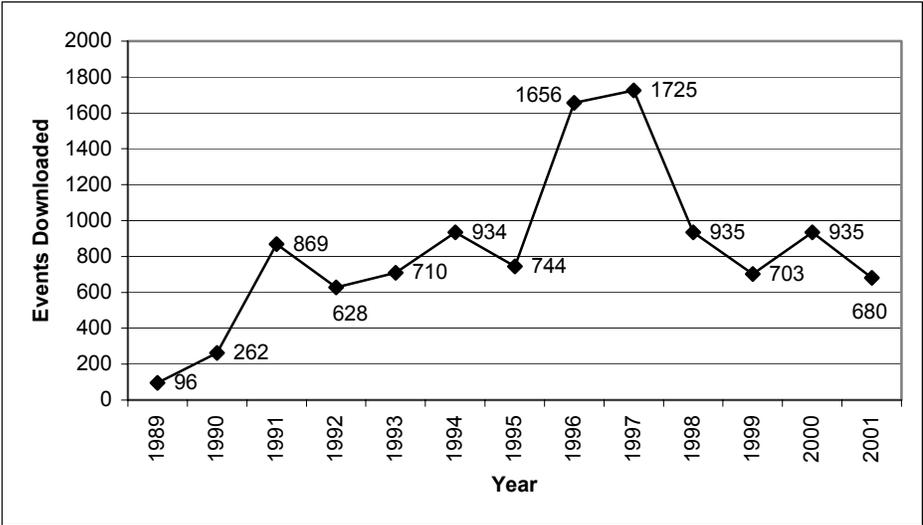

Figure 1: Relay Events Downloaded Each Year

Figure 1 shows the number of relay events that were downloaded each year. Table 2 shows a breakdown by year of the event files and how the data was reduced for this analysis. All of the analysis presented in this paper is from events where the relay initiated a trip. Keep in mind the input data when considering the statistics. When the events were downloaded it was not a systematic approach. This analysis was not considered at the time the events were downloaded. So there may be a few duplicate events or even a few tests that were recorded. It is estimated from a manual sampling and an understanding of the download process over the years, that any duplicate data or fictitious events will have less than a 5% impact on the results.

The available number of events for analysis is 17,020. With every event including 11 cycles of data or more, that comes to about 52 minutes of data. It doesn't sound like much from that perspective. However, after processing the available events, the data required more than 9,000 megabytes of storage space (490 kB per event). The resulting number of trip events analyzed over 13 years is 3,970 events. That includes approximately 1.2 million instantaneous analog values and 3.5 million digital bits of information converted into the data presented here by using about 18 million calculations.

The processing included sorting the events into different relay types and then applying an analysis tool to each event. Using a Cirrus 466 MHz processor with 256 Kbytes of RAM, it took approximately 4 seconds per event to sort and about 4 seconds per event to apply the analysis tool. Just the computer time alone amounted to about 38 hours to process all of the events once. Because of iterations in the development and analysis, portions of the process were run more than once.

Table 2: Available Data

Year	Relay Types	Event Files	Analyzed Relay Types	Processed Events	Analyzed TRIP Events
1989	4	116	2	96	25
1990	4	353	3	262	88
1991	7	1346	4	869	180
1992	9	1062	4	628	176
1993	7	1578	4	710	263
1994	9	1571	5	934	348
1995	9	1044	5	744	310
1996	14	2535	6	1656	639
1997	17	2594	6	1725	589
1998	14	1461	6	935	384
1999	13	1020	6	703	326
2000	16	1322	6	935	373
2001	13	1018	6	680	269
TOTALS		17,020		10,087	3970

These trip events apply to several different voltages. The analyzed events include the 60 kV, 70 kV, 115 kV, and 230 kV systems. All other voltages were excluded for this analysis because of limited data or they were not applicable to the transmission system. Throughout the paper the 60 kV and 70 kV are referred to as the 60 kV system. Table 3 and Figure 2 show the breakdown of the number of events per voltage. By far the 60 kV system has the most events, and the 230 kV system has the fewest.

Table 3: Number of Analyzed Trip Events by Voltage

| Voltage	Analyzed Trip Events
60 kV	2202
115 kV	1209
230 kV	164
Total	3575
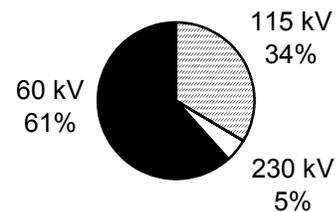
Figure 2: Percentage of Analyzed Trip Events by Voltage

System Parameters

Many system parameters are available from the relay event reports. They can be used to sort the data or for calculations. Some of the system parameters that were used in this analysis are as follows:

PTR and CTR

The potential transformer and current transformer ratios are typically settings in the relay. All of the relay event reports we analyzed included the settings. The PTR and CTR were used to convert the event report data from primary to secondary values or from secondary to primary values depending on the desired report format. The PTR was also used to sort the data by voltage level. For example, PG&E uses a few different types of potential transformers. These have different ratios. All ratios such as 500, 520, 571, and 600:1 were grouped as 60 kV.

Line Impedance

The line impedance was used in fault location calculations. This data is typically a setting and is recorded in rectangular coordinates or in polar coordinates. The value may be primary Ohms, secondary Ohms, or in per-unit. The calculations converted the data to the desired format. The following is an example of how the line impedance in primary Ohms (rectangular coordinates) is converted to secondary Ohms (polar coordinates). Although a mathematically simple calculation, it is extremely important to make sure that all analysis results are in the same units and format to compare the data. It is easy to confuse data from one relay type that reports voltages in kV and another that reports voltages in secondary quantities.

Formula Box 1

Data in the relay settings

$$R1 := 23 \qquad X1 := 98 \qquad CTR := 160 \qquad PTR := 1000$$

Conversion to secondary quantities in polar coordinates

$$Z1 := R1 + X1i$$

$$Z1mag := \sqrt{R1^2 + X1^2} \cdot \frac{CTR}{PTR} \qquad Z1ang := atan\left(\frac{X1}{R1}\right) \cdot \frac{180}{\pi}$$

$$Z1mag = 16.106 \ \text{ohms} \qquad Z1ang = 76.792 \ \text{degrees}$$

Other Settings

A few other settings were used in the analysis such as the ground time overcurrent pickup, the ground instantaneous overcurrent pickup, and phase distance reaches.

Breaker Operate Time

In addition to analog quantities, most relays also include digital indication of inputs, outputs and relay logic. The breaker status is a common input into most relays. Sometimes there is a dedicated input for the 52A, but it also may be user selectable. If a utility standardizes on a

particular input for the 52A the analysis is simpler. If the 52A is connected to different inputs for different installations, the analysis must adapt to this.

This analysis measured the breaker operating time using two methods. The first method uses digital indication from when the relay made a decision to trip until the 52A input deasserts (breaker opens).

The second method was defined by the same trip initiation by the relay, but measured the time until all three-phase currents dropped below 50 Amps primary. Note that because microprocessor-based relays use a digital filter, the actual primary current will be zero for a period of time before it is indicated as zero by the relay event report. This is in contrast to the delay of the 52A digital input. This is only about one processing interval from when the 52A actually changes. If the 52A is wired through an auxiliary relay the breaker status indication will be delayed.

The trip initiation was determined by looking for a particular character in the event report in a certain column. Figure 3 is a screen capture of an event report of one relay type and dialog boxes to illustrate these measurements.

```
 WEBER CB 52 DEVICE 667/667NBU-6              Date: 6/17/0      Time: 08:13:50.625

 FID= 167-5-R405-V656mp2l2-D980417

            Currents                    Voltages        Relays Outputs Inputs
             (amps)                       (kV)
                                                         565565 TCAAAAA DPBD5E
  IPOL     IR     IA      IB     IC     VA     VB     VC  071071 PL1234L TTTC2T
                                                         PPPNNN              A

 [3 Cycles of pre-fault data removed for this example]

     5      2   -113     107     13  -32.0   28.5    3.4  ...... ....... ....*.
     0      2    -50     -82    126  -14.1  -23.1   35.3  ...... ....... ....*.
   -10  -1232    107   -1321    -19   31.4  -19.6   -4.3  ...... ....... ....*.
     0  -3589     69   -4077   -113   14.3   18.1  -34.8  ..P... ....... ....*.

     5   7808   -107    8432     25  -30.2    6.6    5.5  1.P1.. .P..... ....*.
     0   6673   -107   11892    107  -15.0   -5.8   33.5  11P11P *...... ....*.
     0 -10002    126  -15328    -31   29.4   -1.9   -5.8  11P11P *...... ....*.
     0  -9323    132  -16328   -113   15.5    0.2  -32.7  11P11P *...... ....*.

 [2 Cycles of fault data removed for this example]

     5   9830   -170   15932    -38  -28.4    2.8    5.7  11P11P *...... ....*.
     0   9495   -195   14856    126  -15.8    2.1   31.6  11P11P *...... ....*.
     0 -10795    176  -16291     38   28.4   -3.0   -5.7  11P11P *...... ......
     0  -8530    189  -15026   -120   15.6   -1.7  -31.5  11P11P *...... ......

     0   9705   -151   16309    -38  -28.3    2.4    5.8  11P11P *...... ......
     0   9620   -138   15617     94  -15.8    3.8   31.2  11P11P *...... ......
     0  -7355     69  -13396     19   28.9  -10.8   -5.0  11P11P *...... ......
     0  -8089     57  -10521    -44   15.4    1.4  -31.6  11P11P *...... ......

     0   3672    -13    6110      6  -29.9   21.1    4.0  11P11P *...... ......
     0   3141    -13    3140      6  -14.7  -11.4   32.7  ..P..P *...... ......
     0   -736      6    -736    -13   30.3  -23.0   -4.0  ..P..P *...... ......
     0   -425      0    -422      6   14.3   14.5  -33.2  .....P *...... ......

     0     90      6      82      6  -30.5   23.3    4.2  .....P *...... ......
     0     59     -6      45    -13  -14.1  -15.0   33.3  ...... ....... ......
     0    -12      0       0      6   30.7  -23.4   -4.3  ...... ....... ......
     0    -12      0     -13      6   14.0   15.2  -33.3  ...... ....... ......
```

The TRIP column is indicated by the vertical TP

The 52A column is indicated by the vertical 52A

The asterisk "*" indicates a TRIP decision in row 18 of the event report.

The drop out of the asterisk "*" indicates an open 52A contact in row 31 of the event report.

B phase magnitude is the last phase to drop below 50 A primary. $(0^2+45^2)^.5=45$ This occurs in row 43 of the event report.

Figure 3: Partial event report demonstrating the 52A dropout and current dropout measurements. Both are indications of breaker timing.

Since this relay has 4 rows per cycle, the resultant breaker operate time according to the 52A status input is (31-18)/4 = 3.25 cycles. The resultant breaker operate time according to the filter delayed current drop out is (43-18)/4 = 6.25 cycles.

Care must be taken when determining the pickup and drop out of certain relay elements. Different relays report the digital and analog data differently including some event reports that are unfiltered data as opposed to the filtered data shown above. It may be possible to subtract the filter delay from the operate time, but it was not done for this analysis. A good understanding of the event report formatting for each different relay type is usually available from the manufacturer.

Symmetrical Components

Most relay event reports only include the measured phase quantities, measured neutral current input, polarizing inputs, synchronizing voltage inputs, and sometimes the calculated residual current or 3I0.

Most protection quality measurements will include some form of symmetrical components. These values are derived from the phase quantities using the standard symmetrical component formulas. Reference [1] provides a review of symmetrical components.

Overcurrent Pickup

Both the minimum ground time-overcurrent pickup and the ground instantaneous overcurrent pickup were considered. The reported measurement was the calculated ground current (3I0) divided by the pickup setting at the trip initiation point. This measurement provided a "multiples of tap" report for each fault.

When determining the ground pickup and the ground instantaneous setting, the analysis must pick the appropriate setting. Microprocessor-based relays have multiple overcurrent elements available. If a utility standardizes on a certain element, then the measurement is consistent for each event report. However, if the overcurrent element that is used is different from relay to relay, the analysis must be able to adapt to the other element.

Fault Type Identification

Most relays include a fault type determination in the event report. This is often located in the summary data. This value is easily reported directly through a SCADA system as well. Fault type selection has improved over the past 17 years since the first microprocessor-based relays were introduced. Most microprocessor-based relays cannot be upgraded to use the new fault type selection algorithms. Reference [2] explains one type of fault selection method that is newer than the fault type selection used in most of the relays analyzed. A variation of this newer method was applied to the event reports. The variation consisted of some basic zero and negative sequence checks to determine the difference between phase-phase faults and phase-ground faults. The actual relay algorithm does not need to distinguish between these fault-types because the enabled impedance reach calculations inherently only operate for the proper fault condition.

For example, if the relay determines the fault is a AB or a CG fault, it allows those impedance loop measurements to operate. If the actual fault is a CG fault, the AB impedance loop calculation will not operate.

For this analysis all phase loop impedance measurements were not implemented to completely reconstruct the relay decision, but it could be done.

When implementing relay algorithms we are limited to what is published and any extrapolation from that information. Manufacturers may provide some information in instruction manuals, but technical conference papers are another good source.

Fault Location

Similar to the fault type, most relays include the fault location in the event report. This is often located in the summary data. This value can be reported directly through a SCADA system. Fault location calculations have improved over the past 17 years since the first microprocessor-based relays were introduced. Most microprocessor-based relays cannot be upgraded to consider the new fault type selection algorithms. In particular the fault location is improved with proper phase selection that was discussed in the previous section. A traditional impedance based fault locator was used for this analysis, but the improved phase selection method was used.

Apparent Fault Resistance

The apparent fault resistance of a fault can be measured according to Reference [2]. Also, a method using some basic trigonometry and vectors was used for comparison. The calculation for this alternate apparent resistance is not new, but was done to demonstrate the ability to apply alternate algorithms on historical data. These equations are demonstrated in Formula Box 2 to show that the analysis can include more complex calculations such as trigonometry as opposed to the formulas in Formula Box 1 that only use simple mathematical operations.

Formula Box 2

Calculate R for a fault at location f.

$$\text{Known} : Z, \beta, \theta$$

$$x = Z \cdot \sin \beta = f \cdot \sin \theta$$

$$R = Z \cdot \cos \beta - f \cdot \cos \theta$$

$$= Z \cdot \cos \beta - x \cdot \frac{\cos \theta}{\sin \theta}$$

$$= Z \cdot \cos \beta - Z \cdot \sin \beta \cdot \frac{1}{\tan \theta}$$

$$= Z \cdot (\cos \beta - \frac{\sin \beta}{\tan \theta})$$
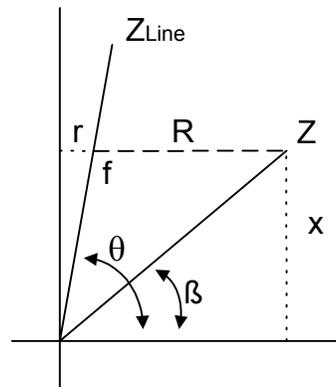
f is in per unit of line length.

RESULTS OF ANALYZING PG&E HISTORICAL DATA

Directional Ground Polarizing Quantities

A common question when setting directional ground overcurrent relays is "what polarizing method is the best."

Electromechanical relays often had to be specified according to the desired polarizing technique. Some electromechanical relays offered a "dual" voltage and current method depending on how it was connected to the CT and PT circuits..

When microprocessor-based relays entered the market, different polarizing methods were available by changing a setting in the relay. And today there are relays that offer as many as three methods. In this case if the methods are all enabled the relay will disable the methods that do not meet certain criteria that are indications of reliable quantities [3]. This allows for complete flexibility in applying the relay for many different applications.

PG&E has guidelines for proper polarizing quantities. In particular for zero-sequence voltage or negative-sequence voltage polarized relays. The secondary polarizing quantities for fault conditions should exceed 5 V for the 3E0 measurement, and 2.5 V for the E2 measurement to meet PG&E guidelines. PG&E still tries to follow these guidelines for microprocessor-based relays due to the effects of unbalance and other factors affecting the voltage on the relay.

If minimum polarizing quantities cannot be met PG&E has installed new switching stations to shorten the line, applied ground distance, and used negative sequence impedance polarizing. Ground distance is difficult to set correctly on mutually coupled lines and can be rendered ineffective by fault resistance [4].

Figure 4 shows the average polarizing values for the trip events that involved ground. Note that in all cases the zero-sequence (3E0) quantity was greater than the negative sequence quantity.

Figure 4: Average Polarizing Voltage of Trip Events

Because faults in certain locations generate a significant amount of zero-sequence voltage, the absolute measurement of zero-sequence voltage for all faults may shift the average dramatically. A better measurement for considering protection quality with regard to polarizing voltages is shown in Figure 5.

In the case of the 60 kV and the 115 kV events, a significantly higher percentage of trip events exceed the PG&E voltage polarizing guidelines.

In the case of the 230 kV, the percentages are statistically identical, but at lower transmission voltages it is clear from this graph that negative sequence voltage polarizing for ground faults exceeds guidelines more often than zero sequence polarizing.

Ground Faults Where the Polarizing Voltage Exceeded Guidelines


Figure 5: Ground Faults Exceeding Polarizing Guidelines in Percent of Trip Events

For a Directional Carrier Blocking scheme the proper polarizing quantity must exist for some out of section faults as well. This is primarily a concern on mutually coupled lines. A fault on a mutually coupled line may invert the zero-sequence voltage such that the fault appears to be on the line. Many books and papers have discussed this, but a basic explanation of the inversion can be found in a well-known text, Reference [5] section "Mutual Coupling and Ground Relaying." Negative-sequence voltage induction due to mutual coupling has negligible effects on relaying.

Breaker Operate Time

PG&E still has a large population of breakers in service that were built in the late 1940's and the 1950's. Some in service breakers are almost 80 years old. Table 4 shows a breakdown of the type and average age of breakers on the PG&E transmission system.

Table 4: Number of PG&E Transmission System Breakers and Average Breaker Age

Voltage	Air	Oil	SF6	Total
60/70 kV	0	419 (39 yrs)	244 (7 yrs)	663 (27 yrs)
115 kV	0	674 (34 yrs)	341 (6 yrs)	1,015 (24 yrs)
230 kV	8 (31 yrs)	324 (29 yrs)	226 (10 yrs)	558 (27 yrs)
Total	8 (31 yrs)	1417 (34 yrs)	811 (7 yrs)	2236 (25 yrs)

Figure 6 shows the breaker seal (52A) operate time and the time it takes for the fault current to drop below 50 amps primary in each phase. Significant differences can be seen between the two methods of timing the breaker. Some of these differences can be explained, and some others will take further investigation.

The breaker seals used on 230 KV breakers applied with high-speed protection schemes are often adjusted by PG&E. Seal stacks in 230 kV breakers were set to follow the "just part" of the main poles, and a set of high speed contacts were set to part before the main poles. Often these contacts were wired to the microprocessor-based relays breaker seal input. If spare breaker seals and wiring are not available, frequently at 115 KV and 60 KV, an auxiliary relay is often used to provide the needed breaker seal. Usually wired to a slow breaker seal, this results in delayed breaker seal input to the microprocessor-based relay.
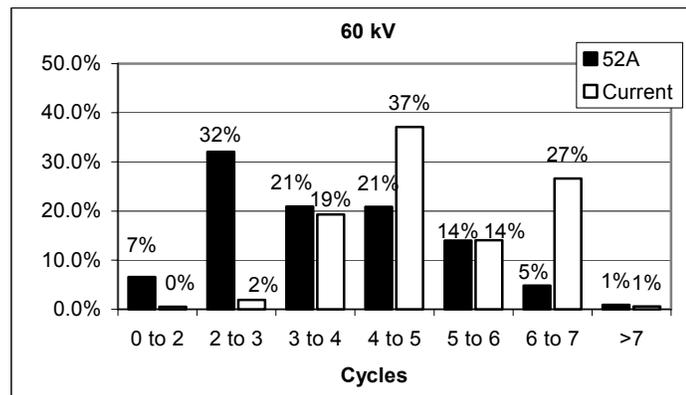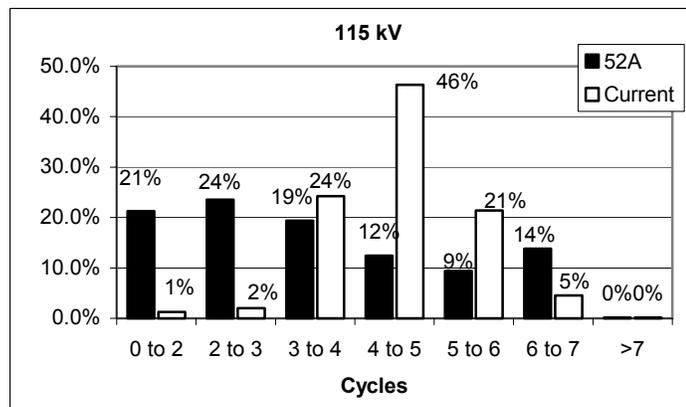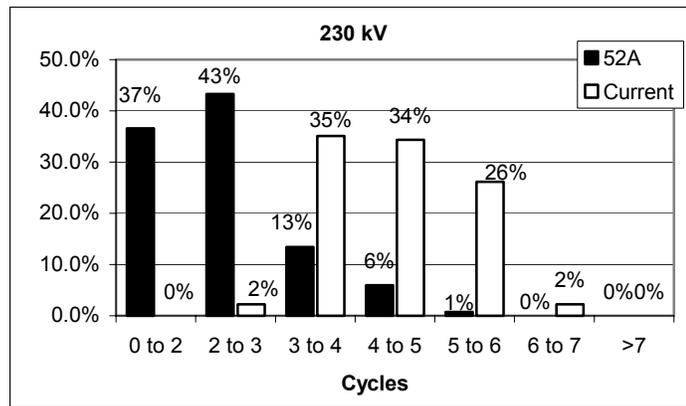
Figure 6: Breaker Opening and Interrupting Time

How Fast is a Breaker?

According to Reference [6], "opening time" of the breaker is defined as the contacts parting time. This is followed by an "arcing time". The breakers "interrupting time" is shown as the total of these two. This can lead to confusion when looking at the specified speed of a new breaker, the tested breaker speed, and the actual interrupting time of the breaker. After analyzing microprocessor-based relay data, maintenance personnel have occasionally been dispatched to

test a breaker that tripped too slowly in the view of the Protection Engineer. Usually the breaker is tested and maintenance personnel respond that the breaker tests within specifications. This can be caused by several different factors.

1. Low Voltage Testing: Maintenance testing usually measures breaker speed with a small test voltage across the breaker poles. This does not take into account the "arcing time" of an actual fault.

2. Breaker Seal (52A) Timing: Some maintenance testing times the breaker from the breaker seal introducing a positive or negative timing error.

3. Dormant Breaker: If a breaker has not operated for a long period of time it can take a "set." This is more common if the breaker is poorly lubricated or if improper lubricants were used. This may result in a slow fault interruption and then tests that are within specifications because the breaker has been exercised.

4. Filter Delays: Digital relay sampling and filtering techniques can introduce additional delay by slowing down the apparent current drop out. Manufacturers often provide element dropout curves, but typical times range from 0.4 to 1.6 cycles depending on the type of filter and current magnitude.

The 60 KV interrupting times shown in Figure 6 are not very uniform. This may be due to the wide range of ages of the breakers. The 115 KV and especially the 230 KV breaker interrupting times are faster and are more tightly grouped with respect to time. A future application might be to compare interrupting times for the same breaker over several years. This could be used as an indicator for maintenance. This feature could be included in future relay designs or could be done as part of a database.
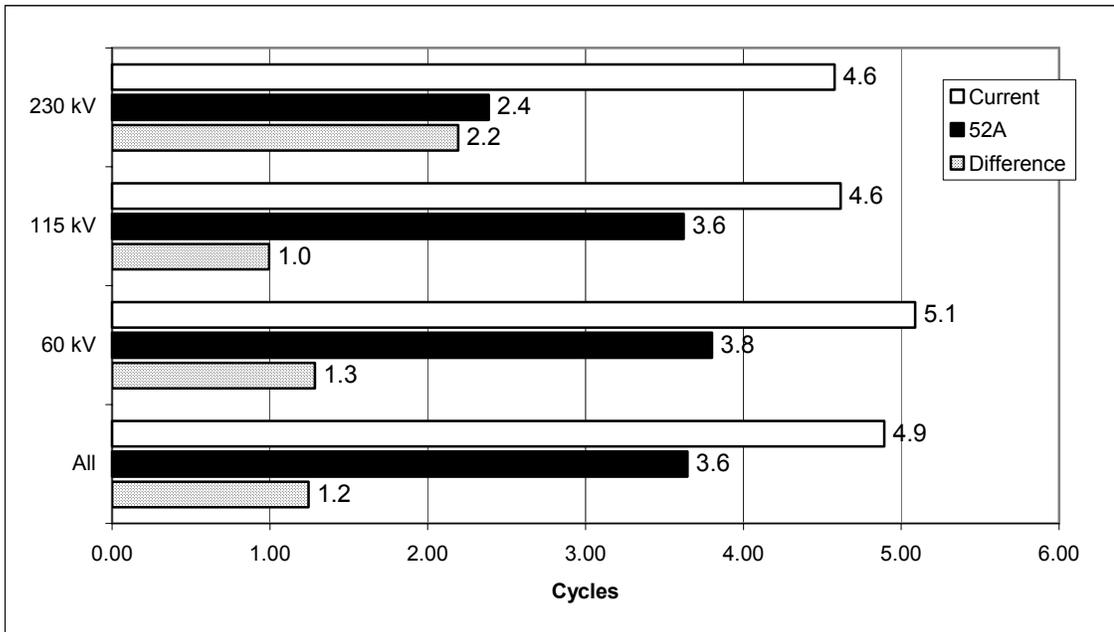
Figure 7: Average Breaker Opening and Interrupting Time

The primary function of a circuit breaker is to interrupt fault current. The best measure of how it performs this function is to track the fault current interruption time. Figure 7 shows the average

time it takes from relay trip initiation to all three phase currents dropping below 50 amps primary. It is surprising to note how relatively slow the 230 KV breaker times are in Figure 7. Some of this time delay is due to the current drop out delay caused by digital sampling and filtering, but this should be uniform for all voltages. The 230 KV has the largest difference between the 52A seal change and the fault current interruption time. Some of this difference may be due to the adjustment of the breaker seal and the more common use of auxiliary relays to provide simulated breaker seals for the lower voltages.

Ground Overcurrent

All relay events were sorted so that only trip events were considered. Two different methods were used to determine if the fault involved ground. The first method only included faults where 3I0 was greater than the Ground pickup. The other method only included faults where 3I0 is greater than 10% of I1. These two methods only differed from each other by 0.8 % of the total trip events considered.

Ground Instantaneous

The 500 kV and 230 kV lines are the backbone of the PG&E transmission system. The older 230 kV protection schemes usually consist of a high-speed protection scheme using power line carrier and a second non-pilot scheme. They are almost always 2 terminal lines with no taps.

The PG&E 115 KV system typically uses step distance and directional ground overcurrent schemes. The lines are mixed between two terminal, three terminal, and lines with multiple tapped substations. PG&E, transmission load customers, or generators can own these tapped stations. Most of these tapped stations are zero sequence sources.

The PG&E 60 KV system is designed like a distribution

system. Most lines are radial and most serve multiple tapped substations. Three or four tapped substations are not uncommon, with many stations having two transformers.

When multiple taps are installed on a transmission line, many compromises must be made on the protection settings. PG&E guidelines call for setting the instantaneous of a directional microprocessor-based relay at 1.15 to 1.2 times the remote bus fault. If this is done on lines with tapped stations, a fault in one tapped bank will relay the entire line. This provides unacceptable service reliability, so instantaneous settings are usually increased to cover less of the line. This is graphically evident in Figure 8. 230 KV ground faults pickup the ground instantaneous elements 80 % of the time. This is an indication of the non-communication scheme coverage. 60 KV ground faults pickup the ground instantaneous only 13 % of the time. PG&E should re-examine the risks of building a 60 KV system based on multiple taps.

230 kV

Ground Inst. 80%
Ground Time 20%

115 kV

Ground Inst. 33%
Ground Time 67%

60 kV

Ground Inst. 13%
Ground Time 87%
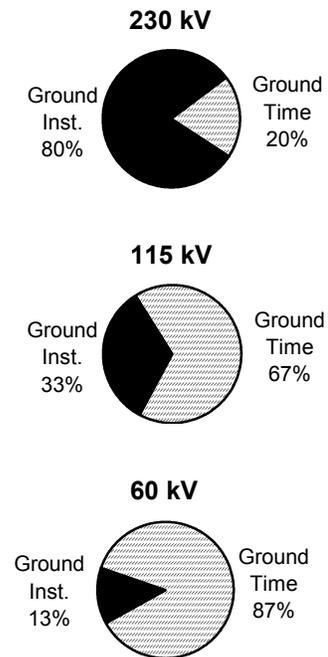
Figure 8: Instantaneous and Time-Overcurrent Ground Pickup in Percentage of Total Trip Events Involving Ground

PG&E guidelines call for setting the ground instantaneous at 1.15 to 1.20 times the remote bus fault current. Contingencies such as parallel line out should be used to obtain the highest setting. On long lines this should result in instantaneous settings that are far below a close in fault. Figure 9 shows that the majority of instantaneous operations occur at 1 to 2 times that instantaneous setting. This is partially due to settings based on contingencies and partially due to instantaneous settings that try to avoid overreaching tapped stations. It is still surprising that such a high percentage are within 1 to 2 PU and that this is roughly consistent across voltage levels.
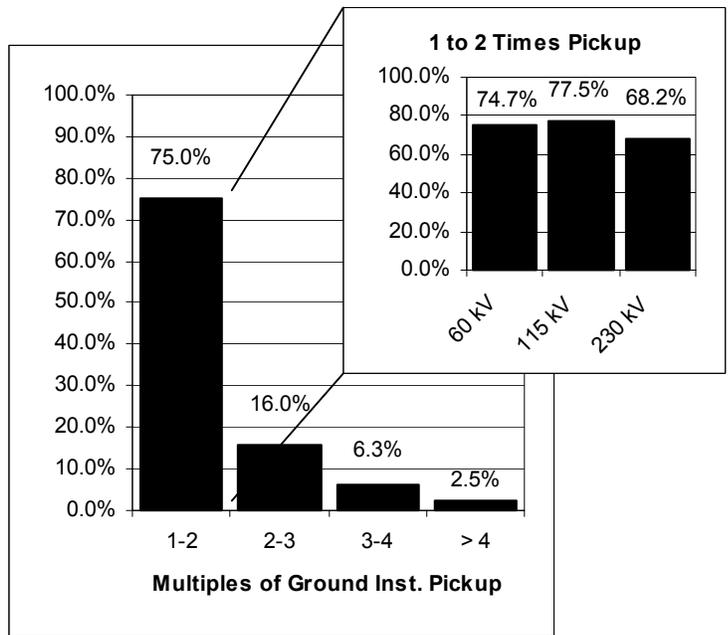
Figure 9: Instantaneous Trips by Multiples of Pickup

Ground Instantaneous

Tracking the correlation between ground faults and the minimum pickup is one way to examine the suitability of using a safety factor of 2.0 when determining ground relay settings. PG&E guidelines recommend setting ground relays at or below 50% of the remote bus ground fault current with the strongest source out behind the relay. On short lines the settings are often much less that 50%. Figure 10 shows that 93.1% of ground faults exceed two times the minimum to trip.
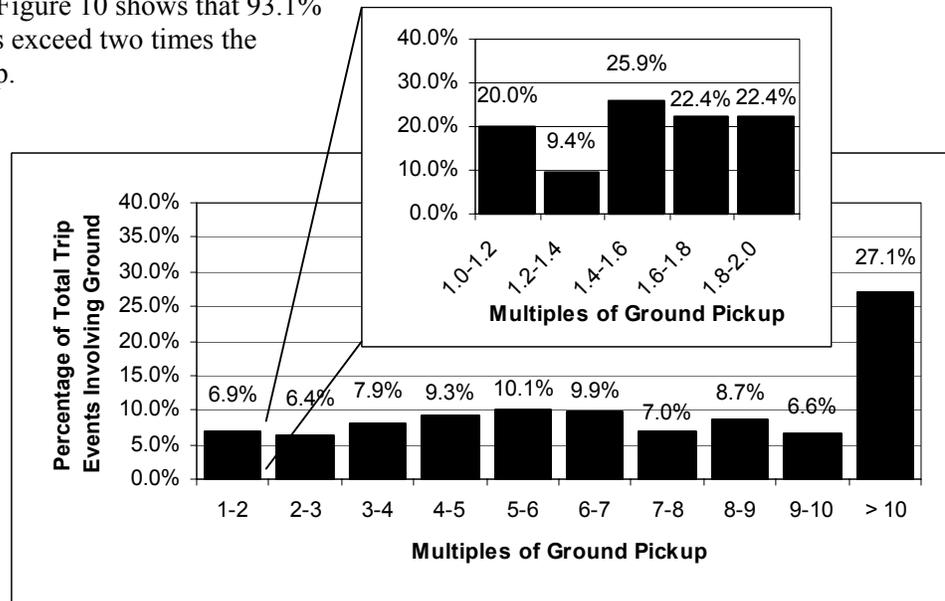
Figure 10: Ground Pickup Events (Instantaneous Pickup Events Excluded)

An examination of the 6.9% of ground faults that are between one and two times the minimum to trip reveals that the number of faults in this area are fairly evenly distributed. These faults may be the result of abnormal configurations, but are more likely caused by fault resistance.

14

Fault Type Identification

Occasionally, certain temporary operating conditions or coordination difficulties require a deviation from the protection guidelines. For example, a phase overcurrent relay may need to coordinate with a phase distance relay. During a clearance condition the relays may not coordinate properly. The protection engineer must understand the risks associated with this operating condition and be able to explain them to operating personnel.

Many risks are associated with the probability that a fault will occur (i.e. storm approaching, construction crews in the station, new line being installed in the right-of-way) and more specifically the probability that a certain fault type will occur. In the coordination example mentioned above, the protection engineer can benefit from knowing the probability of a multi-phase fault. If the probability of a multi-phase fault is small, then the temporary coordination miscoordination may be acceptable.

Determining the fault type is simple from a text book approach, but the reality is that faults are dynamic and load exists. A good example is Figure 11. This figure shows an actual 60 kV fault. How would you classify this fault? The correct answer is phase to ground, phase to phase, three phase, or evolving. Faults like this can skew the relay results when determining fault type.
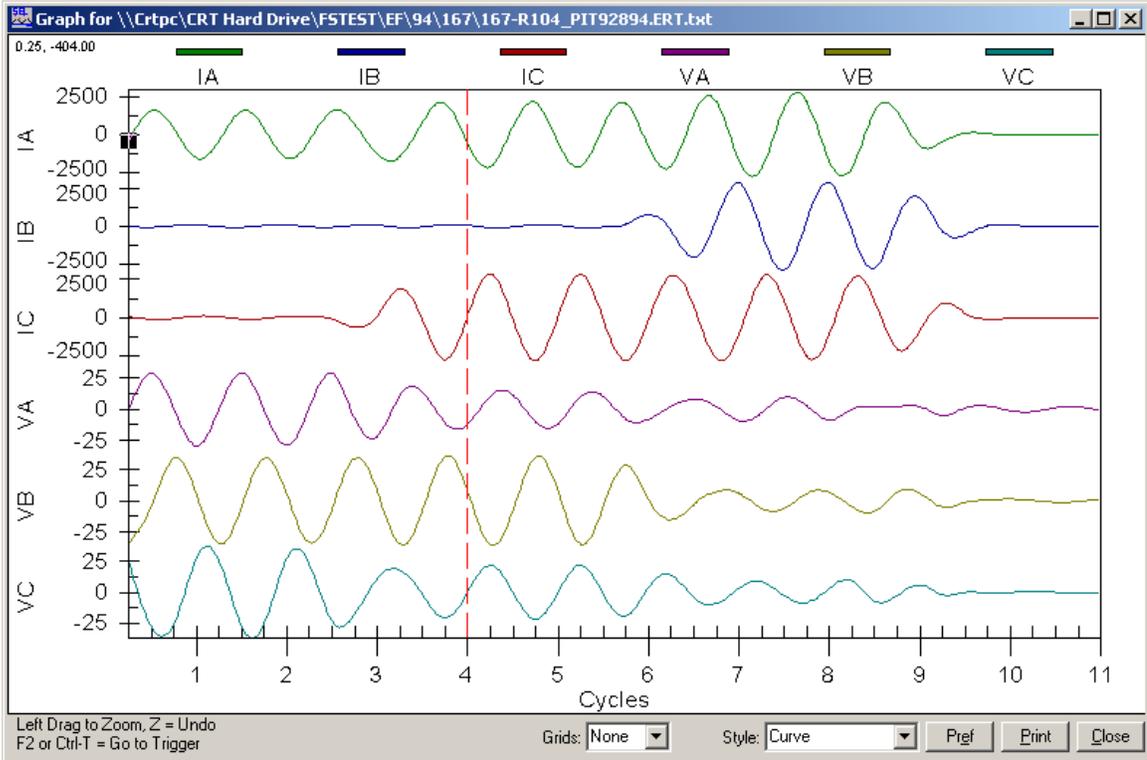
Figure 11: Oscillographic Display of an Evolving Fault Recorded by a Relay

This analysis considered the fault type determined by the relay and also a second fault type selection method. Figure 12 shows that most faults are phase to ground faults. It also shows that the higher the voltage, the lower the probability for a multi-phase fault. The second fault selection method provides similar findings also shown in Figure 12, however the multi-phase faults are less across all voltages.

The second method corrected some inaccuracies in how some of the older relays determined the fault type. They would determine that more phases were involved in the fault because of heavy loads and low fault currents. The second method is not perfect but provided a better representation of the distribution of fault types than the relay output.
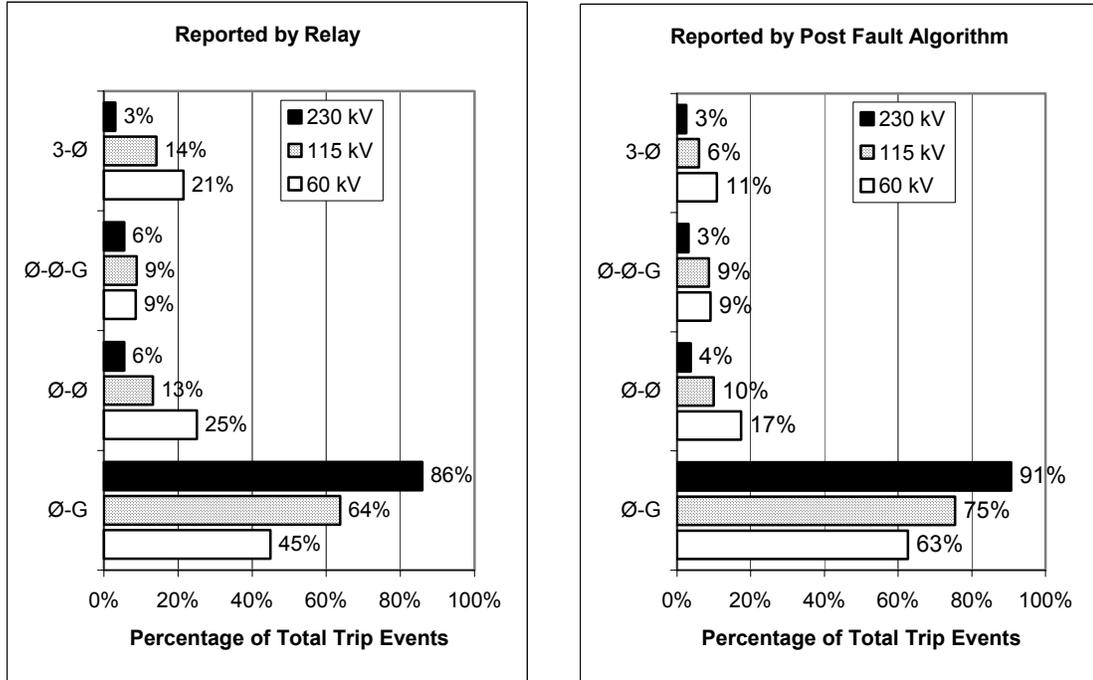

Figure 12: Fault Types Reported by the Relay and a Post Fault Algorithm

Line construction is often referred to using "equivalent phase spacing." This reference is not the distance between the phases but is directly related to the phase spacing. Since a typical line has three phases that are not always equidistant, an equivalent spacing is determined and also referred to as the geometric mean distance (GMD).

PG&E transmission lines have roughly a 7 to 8 feet equivalent spacing for 60 kV, 9 to 11 feet for 115 kV wood construction, 11 to 14 feet for 115 kV steel construction, and 20 to 35 feet for 230 kV. Looking at the equivalent spacing relative to the line-to-line voltages, the expectation is that the higher spacing to voltage ratio would have less multi-phase faults. The data shows this.

Another consideration of the percentage of multi phase faults includes the exposure. 60 kV lines are more likely to be exposed to trees in the PG&E system and a tree is more likely to span between phases for 60 kV than for 115 kV or 230 kV.

PG&E uses this fault type information to assess the risk when deviating from a protection guideline. This data will be reviewed with the PG&E transmission line engineering department to see if any changes are indicated in current design practices.

Fault Location

All of the faults analyzed were trip events. Relay settings are designed to trip for faults within the protected zone (i.e. the transmission line) without other relays tripping. In the event that another relay fails, or the associated breaker fails, then the relay settings are designed to trip for an out of section fault. If a relay trips for a fault in another zone, then a failure occurred or the settings were wrong given the system conditions. Either case is an exception to normal operations. The assumption for the events analyzed is that there may be a few events that involve failures or miscoordinations, but they are statistically insignificant for this analysis. The analyzed events were for faults that occurred on the protected transmission line.

If the faults were on the transmission line, then the fault locator should indicate a location between 0 and 1 in per unit of line length. Figure 13 shows that 21% of the faults were not on the protected line section. Some of these locations that were greater than 1 were due to faults on three terminal lines. Other incorrect fault locations are the result of system conditions including load, fault resistance, and tapped zero-sequence sources.

A second fault location algorithm was applied to the trip events to see how different the results may be. Figure 14 shows the difference between the relay fault locator and the algorithm applied in this analysis. For 62% of the events, the two fault locations agreed (< 10% difference), but for 38% of the events the difference was greater than 10%. We were unable to determine if either fault location method was better because there is no way of knowing the true location of all of these historical faults. What we did find out is that different methods yield different results. By using the relay location in combination with a post fault analysis algorithm, a more precise fault location may be possible for the incorrect 21%. Other double ended fault location methods exist that may be possible to use in this analysis, but it would take the proper programming to correlate the two ends.
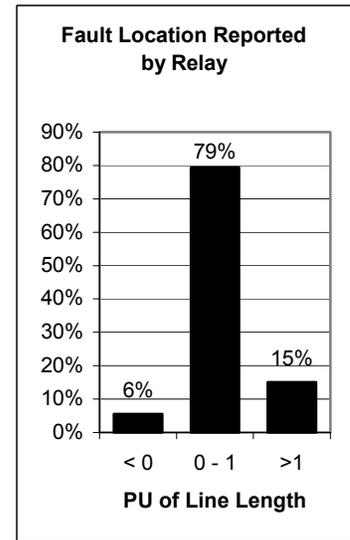

Figure 13: Relay Fault Location
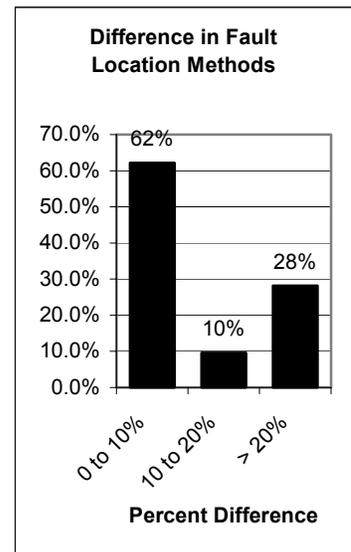
Figure 14: Difference Between Fault Location Methods

Apparent Fault Resistance

PG&E uses a safety factor of two for ground relay settings. The ground relay minimum to trip is set for 50%, or less, of the 3I0 current as seen by the relay for a remote bus fault. This safety factor and the magnitude and likelihood of fault resistance are controversial subjects. The prevailing wisdom at PG&E was that at 60 KV, and higher, virtually all ground faults are bolted faults. This was based on some historical staged fault testing and empirical evidence. With more microprocessor-based relays recording more data, we know that this is not always true based on previous double-ended fault location analysis. We hoped that this statistical analysis would provide hard data on the frequency of high impedance ground faults and the magnitude of the fault resistance at different voltages.

This analysis method may provide a means for getting the necessary data, but at this time the implemented calculations did not provide adequate results. Some different methods that were considered include a resistance measurement based on Reference [2], a vector calculation shown in Formula Box 2, and a comparison of the line angle settings and the measured fault angle for the faulted phase. These three methods yielded inconclusive results except that further study is recommended. Figure 15 demonstrates the inconclusive results. It shows that the when you subtract the fault angle from the line angle, the resulting angle ranges from -180 to 180 degrees. If the results would have been as expected, they would show angles ranging from 0 (no fault resistance) to the line angle (fault impedance is entirely resistive).
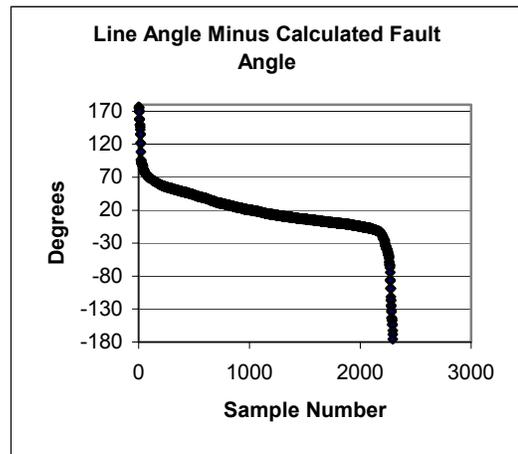

Figure 15: Fault Resistance Considered Using the Fault Angle Versus the Line Angle

Several factors impacting the calculations included load, possible incorrect line angle settings, possible incorrect zero-sequence impedance settings, incorrect phase selections, zero-sequence infeed, and remote terminal infeed.

The following changes would be made for future study and analysis:

1. Subtract load out if the relay event that shows the pickup of the fault is part of the analysis.
2. Cross reference line impedance settings with the fault study data.
3. Use an improved phase selection method.
4. Consider infeed sources by using source contribution ratios from a fault study database report.

ANALYZE MORE DATA IN LESS TIME

To improve your protection quality by mining historical relay data, the following things must be true:

1. Microprocessor-based relays are installed
2. Faults occur
3. Relays record events
4. Events are downloaded
5. Events are analyzed
6. Results are consolidated and reported
7. Improvements are made based on the results

Fault Occurs → Relay Records Event → Data Retrieval (Centralize) → Analysis (Process Data) → Reporting (Consolidate Results)
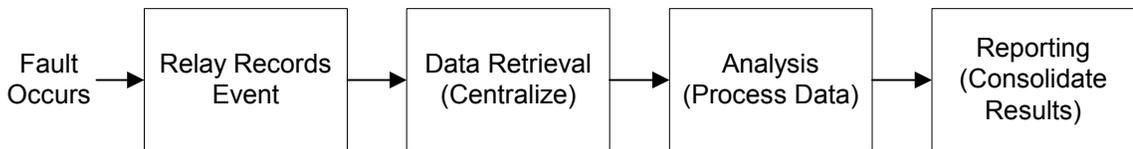
Figure 16: Fault to Report Process Overview

Items 4 and 5 of the above list are explained in further detail in this section. These requirements are the two middle steps of the process shown in Figure 16.

The amount of data available to the protection engineer and other power system personnel is increasing rapidly. In 1989 when PG&E began downloading all events every month, there were less than 200 microprocessor-based relays on the system. This task was quickly identified as taking too long to complete given the existing methods and personnel.

Now with more than 6000 microprocessor-based relays on the system, and virtually no additional personnel, the task of retrieving all of the data manually is unthinkable.

Misoperations and important fault location efforts are the only instances where data is currently gathered. In order to determine what amount of data retrieval and analysis is reasonable, we must consider the methods for retrieving and analyzing the data.

Methods of Data Retrieval

Various methods of retrieving relay event reports span the last 17 years since the first microprocessor-based relay was sold. Originally requiring a computer with a terminal emulator, the relay events could be viewed on the computer screen.

Since then, technology has provided means of retrieving relay event reports via your office computer from remote sites anywhere in the world that have a connection to the World Wide Web.

On-site Download

Many substations still do not have remote communication capabilities. In order to retrieve a relay event report at one of these stations, it is required that someone physically go to the station,

connect a computer, and download the event. Once downloaded the event may be transferred to other personnel via the office network, storage device, or hardcopy.

This task can be very time consuming. In order to minimize the download time, the personnel retrieving the event can utilize the following:

- Scripts: communication software batch processes
- Dedicated PC: configuration is simplified for event downloading
- Handheld PC: small, quick power-up, scripts

Dial-up Download

With a standard phone line in the substation, most microprocessor-based relays can be connected to provide remote access. The simplest method is to tap the line that goes to the substation telephone or use a phone line-sharing device. A modem connected to this line and also to the serial port of the relay provides remote dial-up access to that one relay. Most stations will have more than one relay, so a phone line switch and multiple modems is required, or a single modem and a serial port switch are required. Some manufacturers use a ring communication system with individually addressable relays.

All of the PG&E data was obtained by dial-up modems operating at 1200 baud.

With dial-up access, personnel have the ability to download relay event reports from any computer and modem. Security becomes a concern as soon as the relay is connected to the outside world via a communication media. Reference [7] discusses these and other security concerns.

The dial-up download process is similar to the on-site download process except for one additional step: dialing the modem and connecting to the remote station/relay. Downloading events is a simple task with the following items in place:

- Communication software
- Phone numbers
- Diagrams for relay/serial switch port assignments
- Computer
- Modem

Some things that can cause problems with dial-up downloads include bad phone lines, improper modem settings, improper relay communication parameter settings, and failed modems.

Automated Download

Once the communication infrastructure is in place, automated data retrieval becomes a software issue. Automatically retrieving relay event reports can be challenging because of the following reasons:

- Different formats of data that range across the many manufacturers
- Amount of data (size and quantity)
- Limitations of control over the infrastructure

Multiple Formats

Because many relay manufacturers use different proprietary software to retrieve and display their event reports, it is often required to have multiple software packages to retrieve the reports. A software package could be developed to incorporate multiple vendor formats, but the problem is compounded by different formats between vendor model types as well. PG&E uses multiple manufacturers on most terminals. Data retrieval is typically limited to the relays that are easiest to access.

Data Size and Quantity

Integrated systems often retrieve relay data such as metering data, breaker status, and trip targets, but they typically do not retrieve relay event reports. One reason for this is because the systems and protocols typically used to retrieve the data are not designed for large packets of data. Event reports can be very large relative to single instantaneous analog metering quantities. Some relays can record events that include 60 cycles of 64 samples per cycle or more. This large amount of data within one event report is beyond the download capability of most integrated systems.

The amount of events that are available for downloading is dependent on three things:

1. Number of system events/operations
2. Relay data recording settings
3. Number of microprocessor-based relays connected for remote access

Within the PG&E transmission system it is estimated that there are approximately 1300 faults per year that could generate as many as 12 event reports for each operation. This includes the pickup event for both line terminals (primary and backup) and two backup terminals (primary and backup), and for the trip event for both line terminals (primary and backup). It is also estimated that PG&E has microprocessor-based relays on 35% of the transmission line terminals. Based on these estimates the number of events available for download could be 5,460 per year.

Why Use Automatic Downloading?

Figure 17 shows how the number of relays has increased each year. This means that the available data for analysis is increasing rapidly. It also shows that the number of relay events downloaded has fluctuated over the years.

Figure 18 combines these two line charts to show the number of relay events downloaded per relay each year. It shows that the downloaded events relative to the amount of data available are decreasing. It is clear that manual downloading cannot keep up with the amount of data available.
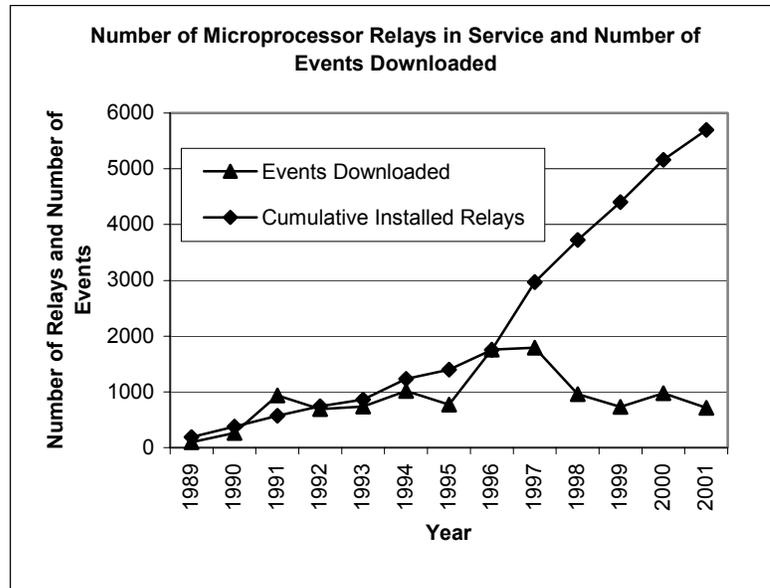
Figure 17: In Service Relays and Events Downloaded by Year
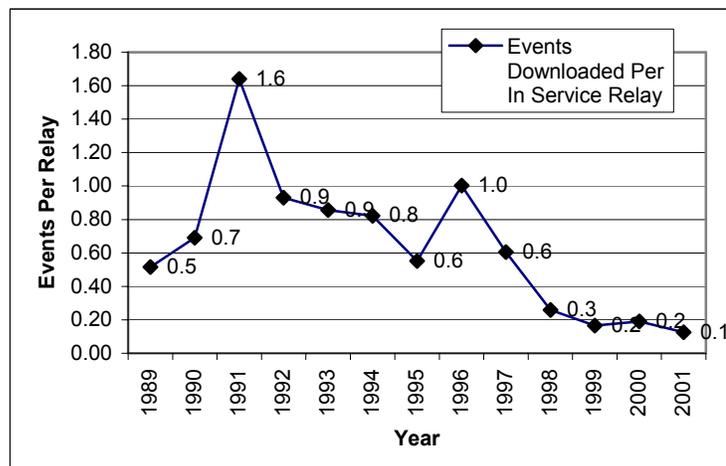
Figure 18: Number of Events Downloaded Divided by the Number of In Service Relays

Two general methods are available for automatic downloading of relay event reports. The relays can be periodically polled to determine if new events exist, or the system can report the event as it occurs.

Polling

The polling method to automatically retrieve event reports is the simpler method of the two. The polling is performed on a time basis such as once a day. This method can be very effective for a small system or for a large system broken into many polling systems. The interval between when the event occurs and the data availability is dependent on the polling interval. This means that if an event occurs just after the poling is completed, the system waits an entire polling interval before retrieving the data. The polling interval must be longer than the longest time it would take to poll every device and download the maximum number of events for each device. This polling interval may become larger than is acceptable in order to provide timely data.

Event Notification

Most relays have an automatic message or logical bit that is generated or changed when an event is triggered. If a system monitors these "handles" to determine when an event exists, it can then initiate the download of the new event. This method provides for the shortest possible time between event trigger and download of the event. The implementation of such a system is more complex than it sounds. The system must continuously monitor or track the "handles" even while it is downloading events. It must be able to distinguish that multiple events may trigger between monitoring intervals. And the system must be able to handle a large volume of trigger notifications all at once.

For example, if a lightning storm rolls through an area, many events are generated. Some events may be generated within a few cycles of each other, while others may be seconds or minutes later. After the relays indicate that an event has been triggered the system begins retrieving events only to have more triggers occur. The system needs to know how to respond to such a situation or data may be lost. One way to control this is to download all trip events first. In order to do this the system must have a way to determine if the event was a trip event. Most microprocessor-based relays have a "handle" that indicates this.

High-speed Communication

High-speed communication connections to the relays provide the infrastructure to efficiently retrieve large amounts of data. The communication is dependent on the hardware, the connection, and the protocol. Reference [10] discusses protection integration more thoroughly, however one method for establishing high-speed communication is to use existing infrastructure at large manned substations that have company intranet capabilities. By adding an Ethernet connection interface for the relays and connecting it to the company intranet, the protection engineer has access to the relay data via various protocols. Telnet provides manual terminal emulation communication and the File Transfer Protocol (FTP) provides a way to transfer large packets of data like event reports.

Methods of Analysis

After the events are downloaded, they need to be analyzed based on the goal of the analysis. If field personnel need a fault location, then the analysis may be simply providing the relay generated fault location. From the previous discussion, more than 35% of PG&E trip events would require further analysis before giving field personnel the fault location. This type of information is required immediately to find and correct the problem to restore service. The faster this information is available, the quicker the line can be restored if the line locks out.

If the analysis is for statistical reporting over time, the time to report can be much longer. In the case of this discussion, PG&E is actually using data that is 13 years old.

Analyzing event reports can be done manually, by using computer tools manually, or by automating the computer tools. These methods are available no matter how the download procedure was accomplished. Even if the event reports are downloaded manually on-site, a computer can perform the analysis automatically.

Manual Analysis

PG&E used to analyze event reports manually. This manual analysis was often done with just a calculator, the system fault study, and system diagrams. Now, PG&E is using more and more analysis programs to read event reports.

Manual analysis includes calculating the symmetrical components for certain data points in the event report. It includes determining timing, and general relay operation. This effort requires a good understanding of symmetrical components, the relay operating principles, the relay reporting format, and a knowledge of the system. Each engineer that intends on doing the analysis is required to have this background.

Computer Aided Manual Analysis

There are many analysis tools available to protection engineers. In addition to the simple calculator, computer software programs are available for crunching the numbers. Some common analysis programs include the following:

Manufacturer Event Report Analysis Software

Most relay manufacturers provide or sell analysis software for their products. This software typically displays the event reports in a readable format including phasor and oscillographic plots. The basic symmetrical components are usually calculated, digital timing is indicated, and some basic summary information about the event is reported including targets and settings.

This software is proprietary and cannot be changed by the user with the exception of how the data is displayed on a per event basis. Many digital fault recorder software packages include further analysis tools.

MathCAD

An off-the-shelf software package that is an excellent tool for protection engineers is MathCAD. This is an equation editor and analysis program. Unlike a spreadsheet it displays the formulas in

mathematical format for easy reading and checking. It allows data to be imported through links or data input files.

A MathCAD file could be designed to read event reports and present data such as what is presented in this paper but on a per event basis. The consolidation of the data becomes more difficult with MathCAD than with other solutions. MathCAD is also not widely used by protection engineers, but it is becoming more popular.

Microsoft EXCEL

Excel is what was used for the event analysis presented in this paper. It was also used for consolidating the data and generating the graphics. Excel is available on almost every business computer. Its drawbacks include documenting the analysis and reviewing the calculations for accuracy.

Excel is a spreadsheet program that requires formulas that include row and column references. In many cases a particular calculation requires several mathematical steps that usually can be done in one step in a program like MathCAD.

A big advantage to Excel is its ability to link one file to other files and with other Microsoft products. This feature is how all of the data was consolidated. By having one resultant file that was linked to all of the individual event files, the data was consolidated into a report file.

Software developed by power system software companies

Some power system software companies also make software that analyzes power system data. The research for this paper did not include additional software programs, but there are some that benefit the protection engineer. Again, a disadvantage to proprietary analysis software is that the user often cannot change the analysis algorithm without the manufacturer.

Automated Computer Analysis

A fully automated system is ultimately desired. The results of this paper were generated using a system capable of full automation, but because of the large volume of data, it was completed in automated segments instead of all at once.

A fully automated system requires the setup time and research to have the system provide the proper data. Using the computer aided manual analysis method on a small scale does this. One event is downloaded and analyzed by the computer tool. An event is manually "pasted" into an Excel template and the results are examined. This template must be built prior to the analysis. Each Excel template is designed for a particular type of event data. For example, each relay type may have its own template to accommodate different formats, or each voltage level may have its own template to accommodate calculating different data from different protection schemes.

Once the templates are developed the automation may be setup. The automation is simply a program pasting the event data into the template and consolidating the event files using Excel links to put them into a common file.

Example Excel Spreadsheet for SEL relay

Any ASCII text file may be pasted into cell A1 in Excel. Each row of the text file will be copied into the corresponding row in Excel.

The ASCII file is copied into an analysis tool (spreadsheet) that is prepared for the specific type of report (i.e. mfg1 – relay 1, mfg1 – relay 2, mfg2 – relay1, mfg3 – oscillograph 1). These analysis tools will all be similar, but will have a different front end to parse the different format.
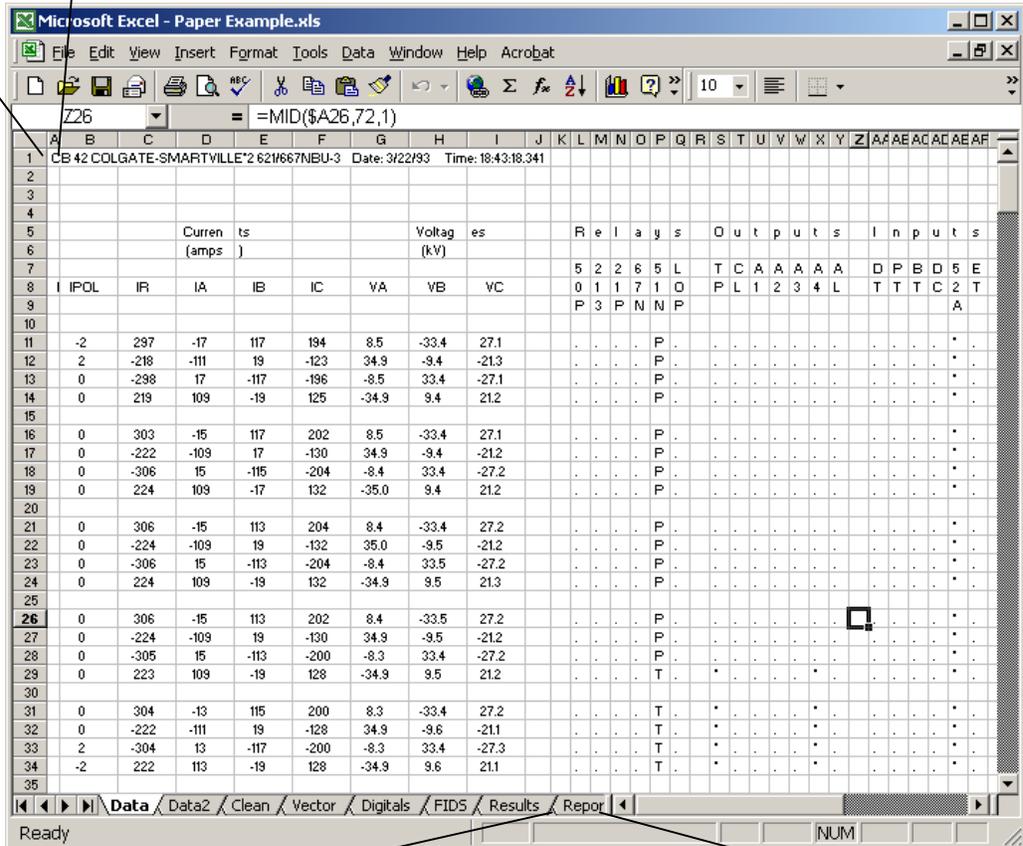
Select the REPORT tab to view the results for this specific event.
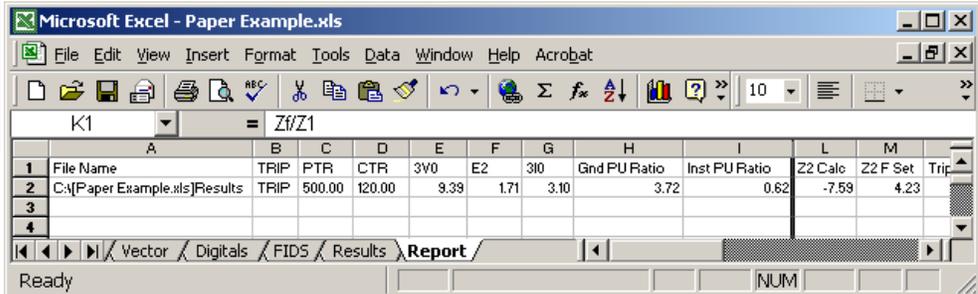
Figure 19: Data Analysis Process

A report file consolidates all of the event reports by using Microsoft links between the report file and the REPORT tab of the generated data file.
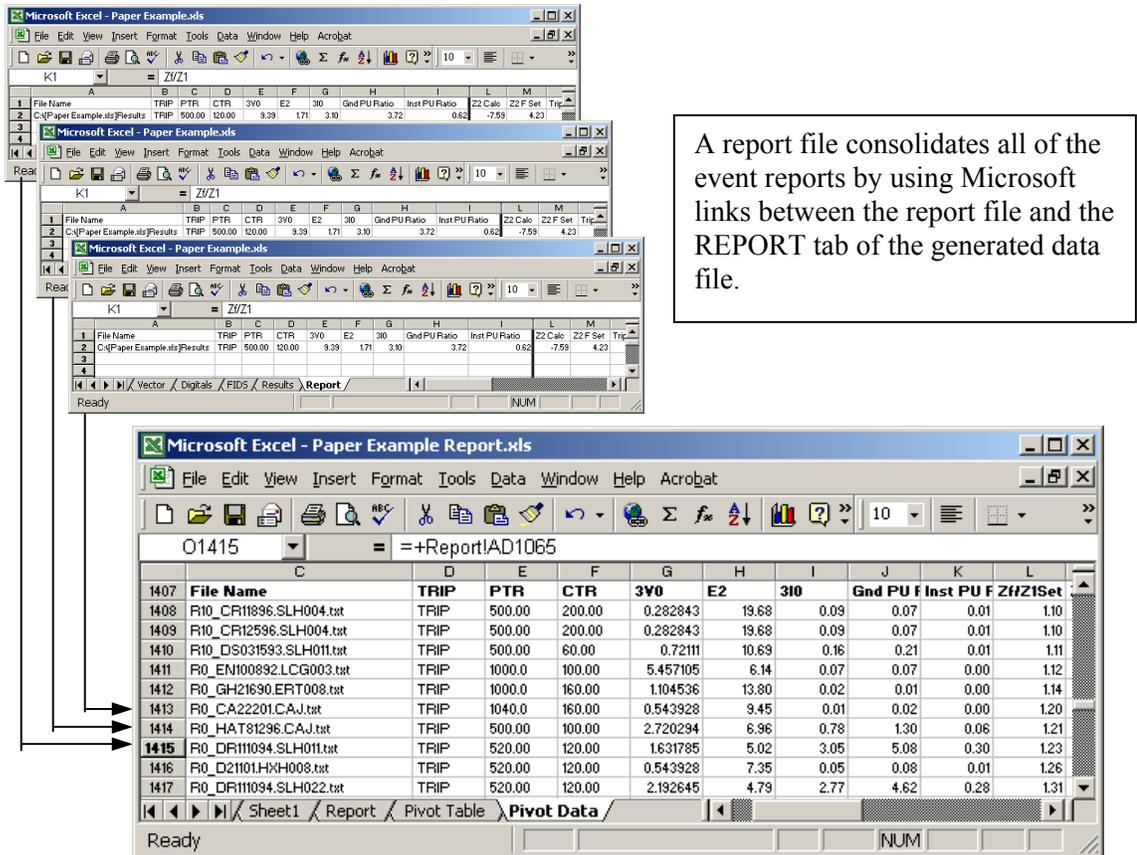
Figure 20: Reporting Process

Example Excel Spreadsheet for COMTRADE File

The above example shows one type of relay, however this analysis can be done on any ASCII based text file that has a consistent format for each event. A good generic example includes the COMTRADE file standard. Many relay and oscillographic manufacturers have the ability to generate COMTRADE format ASCII files. Figure 20 is a screen capture of an ASCII based COMTRADE file that was pasted into EXCEL.
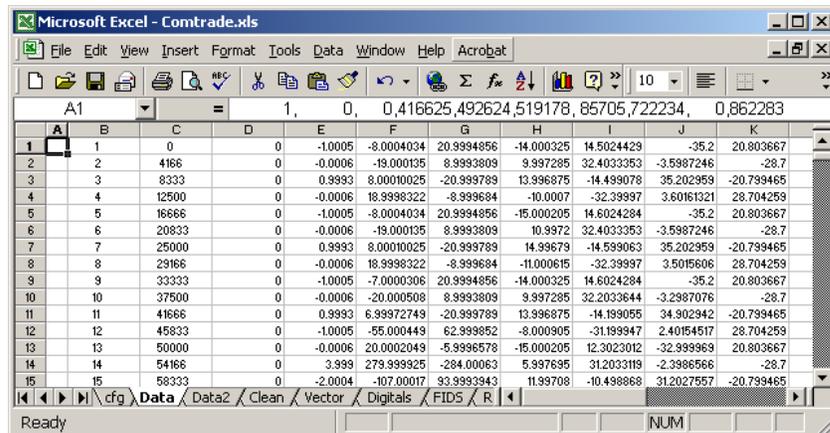

Figure 21: COMTRADE File Pasted Into Excel

CONCLUSIONS

This first attempt at mining relevant data from historical microprocessor-based relay event files reaffirmed some of the PG&E practices and ideas. It also revealed some interesting and surprising results.

1. Overwhelming amounts of relay event data are available to the protection engineer.

2. Storing, mining, and analyzing this data can improve protection quality.

3. Negative sequence voltage polarizing for ground faults is superior in most cases.

4. Breaker interrupting times and the difference between the seal operating times and the current dropout times was a surprise.

5. Large differences in the number of events where 3I0 exceeded the instantaneous ground pickup setting were noted between voltages. 80 % at 230 KV and 13 % at 60 KV.

6. Policy on setting ground minimum is probably adequate, but 6.9 % of the ground faults occurred between 1 and 2 PU of the ground pickup. These faults are of concern.

7. Fault type identification and fault locations on older style relays are often incorrect, especially when based on the trip initiation event for a time-delayed trip.

8. Obtaining fault locations and fault resistance for high impedance ground faults is problematic.

9. As more relay data is available new methods of automating the download process and analysis process are needed in order to mine only the relevant data from the rest.

As high-speed communication schemes and more microprocessor-based relays are installed on transmission systems managing the data can become overwhelming. A well-planned system to automate data retrieval and analysis can assist utilities in mining only the relevant information from the relay event files. This will help to improve protection quality, substation maintenance practices and service reliability to PG&E customers.

FOR FURTHER CONSIDERATION

Several items that may warrant further consideration were identified while performing this study.

- Automated setting checking programs could use statistics obtained by these methods to flag settings that are outside normal ranges. An example would be the ratio of ground instantaneous setting vs. ground minimum in the same relay.

- PG&E has archived digital fault recorder data from 500 KV faults for many years. This data could be converted to COMTRADE format and analyzed using the same methods presented in this paper.

- Firmware revisions for individual relays could be obtained from their downloaded event and entered into a relay database.

- Track individual breaker interrupting times to signal when maintenance is required.

- PG&E plans to experiment with high-speed connection to relays next year. With relay data available by an Internet connection, security and data management policies will need to be addressed.

- The results of this analysis will be discussed with the PG&E transmission line design group, Substation asset management group and within System Protection.

- Further study of the frequency of high impedance ground faults and the magnitude of the fault resistance on the transmission system is needed

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Larry received his B.S. degree in Electrical Engineering from Washington State University in 1992. He worked for Pacific Gas & Electric Company from 1992 until 1995 as a Transmission System Protection Engineer. Larry joined Schweitzer Engineering Laboratories, Inc. (SEL) in 1995 as an Application Engineer. He provided technical training and technical support for customers. Assigned to development teams, he wrote instruction manuals, directional element functional tests, and differential relay acceptance tests. In 1997, Larry started the engineering services department at SEL providing specialized project support to consultants and utilities.

In January of 2000, Larry founded Relay Application Innovation, Inc. to provide electric power system protection applications, analysis, and training. He has performed protection services for a relay manufacturer, utilities, design consultants, industrial plants, and construction companies. Larry has written several application guides and a technical paper about power system protection, monitoring, and control. He is co-author of a patent that is pending regarding protection against slow circuit breaker closures while synchronizing a generator. As a representative of SEL, he served on the Executive Board for the Advisory Council of the Electrical and Computer Science department of Washington State University. Larry is a registered Professional Engineer in several states and is a member of the IEEE Power Engineering Society.

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Ed retired as a Senior Protection Engineer after 23 years with Pacific Gas and Electric Company. He is currently the president of Relay Protection Consultants/ERT and consults for the Utility industry. He assisted by reviewing the results and providing input about the practical application of the data.

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Rick has 20 years of protection experience working for various utilities and a relay manufacturer. He is currently a Protection Engineer for RAI. He assisted by developing some of the analysis formulas and testing algorithms for inclusion in the analysis.

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Yuping is a software development engineer for Pacific Simulation. In her spare time she assisted in the development of the file-sorting tool and automated analysis tool applicator that was used to simplify the data mining process.