Using Power System Event Data to Reduce Downtime

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ABSTRACT

A reliable electric power supply is critical to the success of any industrial facility. Electrical faults and disturbances cannot always be avoided, but a quick diagnosis of problems can reduce downtime. Using event data from digital relays can provide valuable information to identify the root cause of problems and offer solutions. The data can also assist with commissioning during planned outages.

This paper provides real-world examples of industrial applications that demonstrate how to improve electrical power system reliability. These examples include motor protection and starting, transformer and bus protection, main-tie-main applications, and feeder protection.

INTRODUCTION

The electric power industry is devoted to improving the reliability of the electric power supply. Volumes of papers, articles, and industry standards are dedicated to planning, designing, testing, measuring, and ultimately improving power system reliability.

One study estimates an annual loss of $45.7 billion by U.S. industrial and digital economy companies due to electrical power outages [1]. Even short duration outages can be expensive. For example, a 2-minute outage in Taiwan reportedly cost $11 million in lost production for a plastics firm and several petrochemical plants [2].

However, for most processes, the cost of an outage increases greatly with its duration. One survey estimates that a 1-hour outage costs five to ten times more than a 1-second outage [1].

Using power system event data from protective relays provides valuable information to identify the root cause of electrical disturbances and offer solutions. If event data are analyzed and understood, outage durations can be reduced from days to hours, hours to minutes, or, in some cases, be avoided all together.

The event data can also assist with commissioning to help maintain timelines during scheduled outages.

This paper describes a process to analyze event reports and provides several real-world examples of industrial applications that demonstrate how to improve electrical power system reliability.

DEFINITIONS AND PROCESS FOR ANALYZING POWER SYSTEM EVENTS

Most protection principles (i.e., zones of protection, security, dependability, speed, sensitivity, and selectivity) used today have remained constant for decades. Perhaps the biggest advance made in the past 25 years is the availability and widespread use of event reports from protective relays. Whereas in the past, it was difficult to determine the root cause of electrical disturbances, now the root cause can be determined almost 100 percent of the time if the event reports are available.

What is an event report? What process should we use to analyze event reports? The following paragraphs help answer those questions as described by David Costello [3].

An event report is a time-aligned record of the power system voltages, currents, inputs, outputs, and elements. Usually, the event report is triggered when a breaker is tripped by the relay but can also be triggered by other conditions (e.g., breaker closure, input assertion).

The following is a process for analyzing power system events:

1. Understand the expected operation of the system protection and control by knowledge of equipment instructions, settings, one-line diagrams, schematics, the state of the power system, software tools, and training.
2. Collect information from eyewitness testimony, fault location (if known), sequence of events, relay targets, and relay event reports.

3. Gather tools like event analysis software, instruction manuals, and other reference materials.
4. Compare the actual operation to the expected operation.
5. If the operation was as expected, document and save data as a historical test and operational resource.
6. If the operation was not as expected, work to determine root cause, document and save data, develop solutions, and test the solutions as necessary.

Fig. 1 and Fig. 2 show flow diagrams for a consistent process for analyzing events:

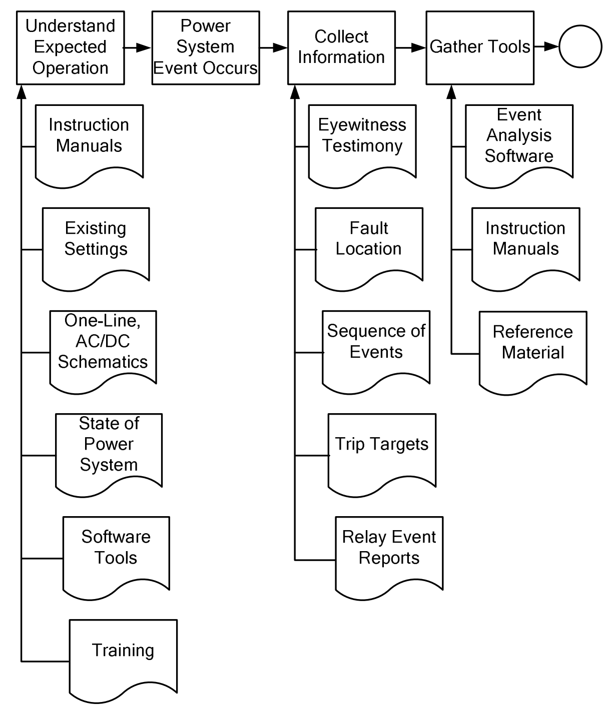


Fig. 1 Process for Analyzing Event Reports (Part 1)

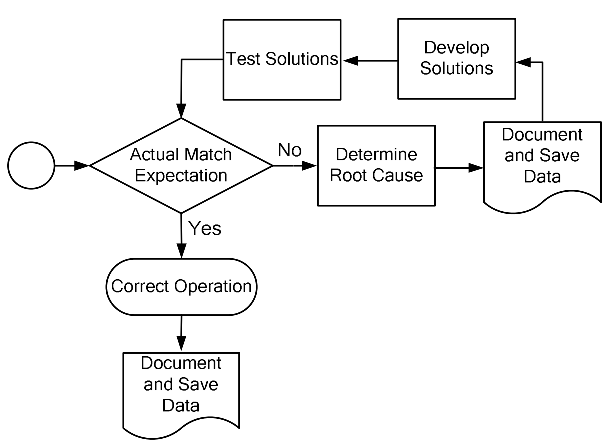


Fig. 2 Process for Analyzing Event Reports (Part 2)

The following section provides actual system examples, an effective method for learning event analysis. We describe and analyze real-world event reports captured from relays at industrial facilities. Many of these events are typical power system disturbances and problems that occur in the field. For each event, we attempt to discover root cause of the problem and offer practical solutions to improve system reliability.

ANALYSIS OF POWER SYSTEM EVENTS

A. Generator Differential Trips During Startup

A newly commissioned one-megawatt generator was in-service for a few hours with a small load that included some plant lights and heaters. After a few hours of feeding the small load, a variable frequency drive motor was started to supply some additional load at the facility. During the motor start, the generator was tripped offline by a generator differential relay. Not convinced of a problem with the generator, the operator brought the generator back up, and it again produced a trip when the motor was started. This led to an investigation to determine the root cause of this operation.

The operator pulled three types of event reports from the relay: an unfiltered event, a filtered event, and a filtered differential event. A screen capture of the unfiltered event (Fig. 3) shows the harmonic-rich currents and voltages at the time of the trip.

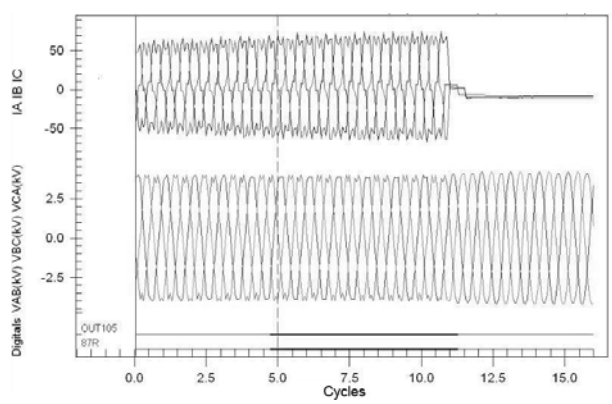


Fig. 3 Unfiltered Event Shows Differential (87R) Trip With Harmonic-Rich Currents and Voltages

Fig. 4 shows the percentage of harmonic current from Phase A, including about 30 percent fifth-harmonic content. This can likely be attributed to the variable frequency drive motor, which injects harmonics into the system. Did this distorted waveform cause the relay to misoperate?

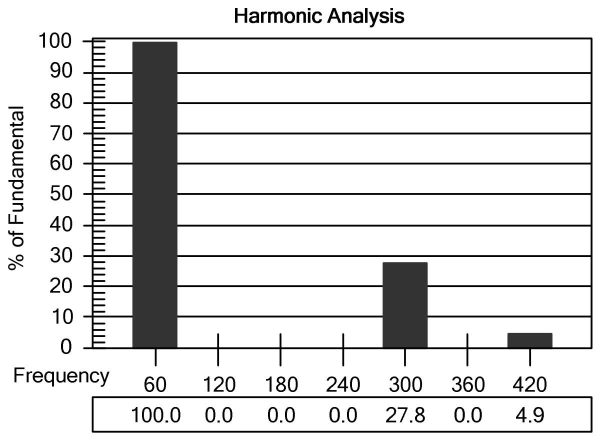


Fig. 4 Harmonic Analysis of Phase A Current

The relay design in question responds only to the fundamental (60 Hz) component for protection. The next screen capture (Fig. 5) shows the filtered event from the relay, which rejects all harmonics. While the screen capture appears to be filtered properly, the differential element (87R) is shown asserted, which trips the generator.

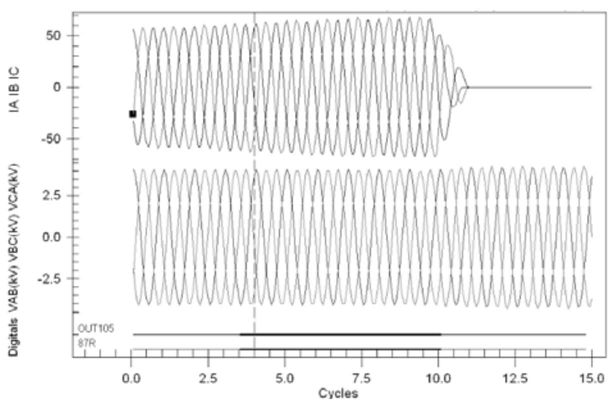


Fig. 5 Filtered Currents and Voltages Used by Relay Protection Elements

If the relay properly filtered the waveform and did not include harmonics in the decision to operate, what could have caused the misoperation? The final event viewed is the differential event, which includes the current inputs from each side of the generator. This event is shown in Fig. 6, using the phasor quantities.

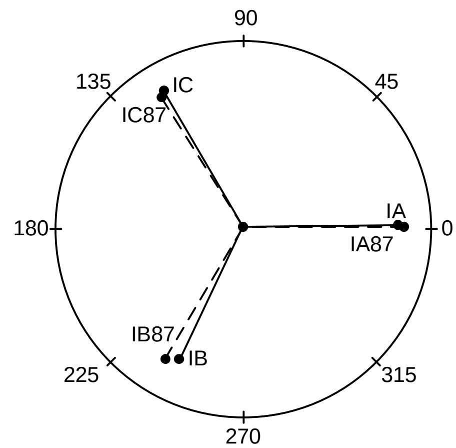


Fig. 6 Differential Event Shows the Phasor Relationship at the Time of the Trip

Measured currents IA, IB, IC and IA87, IB87, IC87 refer to the phasor quantities on the grounded and load sides of the generator. For normal load conditions, we would expect IA and IA87 to be 180 degrees from each other and of equal magnitude. However, the event report indicates that these current phasors are of equal magnitude and in phase. Thus, it appears that polarities on one side of the generator are incorrect, leading to false operating current.

Fig. 7 shows a diagram of the existing connections and the proposed connection to fix the issue.

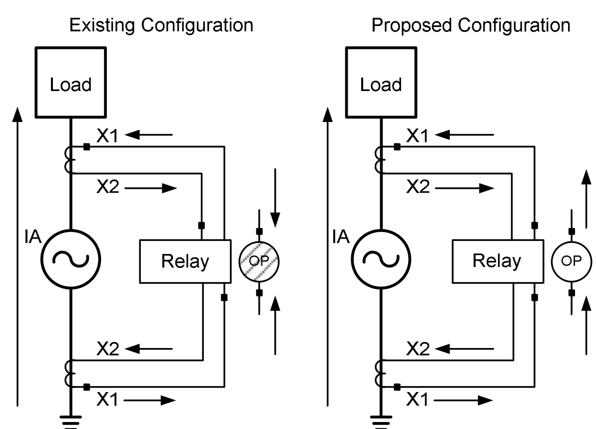


Fig. 7 Existing (Incorrect) and Proposed (Correct) Wiring

Solution: After investigation, field engineers discovered that the polarity of the generator load-side CT (current transformer) was reversed. To fix the issue, the polarity was corrected, as shown on the right portion of Fig. 7.

B. Induction Motor Commissioning

A facility was installing an older, refurbished motor. The motor leads were intact but poorly labeled. Facility engineers wanted to verify that the wiring was correct before placing the motor into service. They used two techniques during commissioning.

The first was to “bump” the motor. Technicians applied a momentary load for about 3 cycles to determine whether the motor primary and secondary wiring were correct for the installation. Fig. 8 shows the voltage and current phasors during this event.

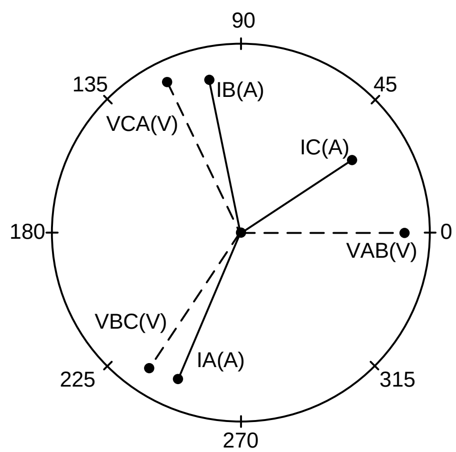


Fig. 8 Motor Bump Start Event Shows ABC Rotation and Inductive (Lagging) Current

The phasors show that the motor currents and voltages are connected with ABC rotation. Also, as expected for an induction motor, the currents lag the voltages (e.g., for a purely inductive load, IA lags VA by 90 degrees and VAB by 120 degrees).

By looking closer at the raw oscillographic data, we observe that the voltages drop (as expected) during the starting condition (Fig. 9). We also discover that all of the currents have some dc offset and that the A-phase current waveform is distorted, indicative of CT saturation.

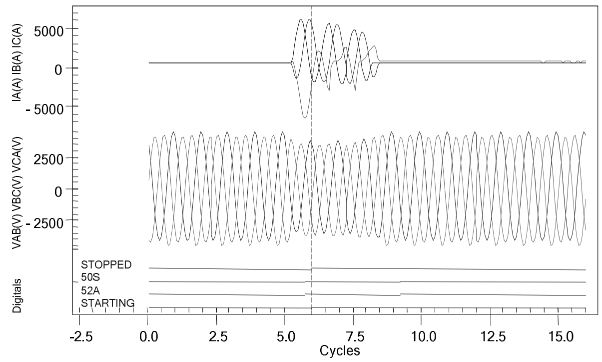


Fig. 9 Motor Bump Start Event Shows A-Phase CT Saturation and Expected Voltage Sag

Note that CT saturation is not necessarily a problem unless it affects the performance of the protection system. In this case, the CT saturation lasts only a few cycles, and we can set the instantaneous overcurrent element pickup above the worst-case inrush current.

To verify this, a second, longer test start was applied to the motor with a low-set overcurrent relay purposely set to trip after 20 cycles. Fig. 10 and Fig. 11 show the start and the trip after 20 cycles. Note there was dc offset but no CT saturation.

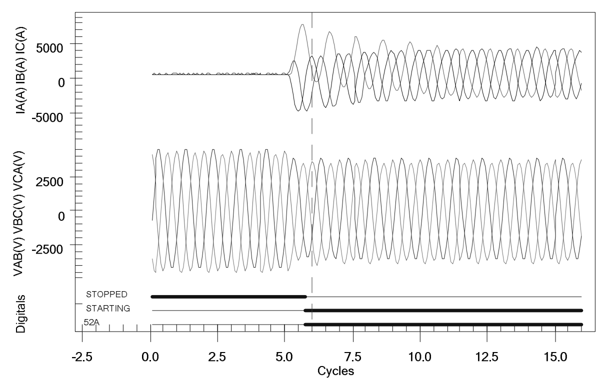


Fig. 10 First Portion of 20-Cycle Motor Start With Planned Trip

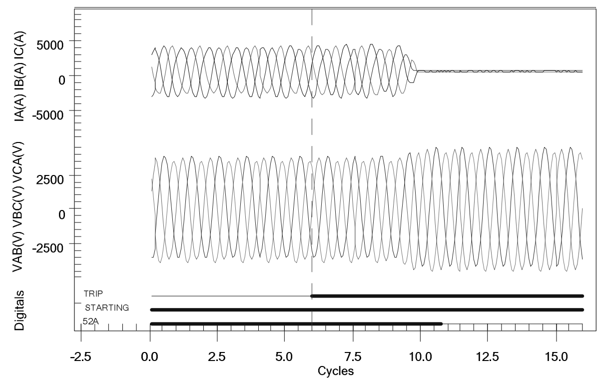


Fig. 11 Second Portion of 20-Cycle Motor Start With Planned Trip

Solution: These tests and the accompanying event report data confirm that the motor is connected properly. Also, the starting currents and voltages are known, which aids in establishing reliable overcurrent pickup and time-delay settings.

C. Main-Tie-Main Fails to Return to Normal After Transfer

Main-tie-main (MTM) schemes are commonly installed in industrial facilities to reduce downtime for loss of a single source. Fig. 12 shows a typical MTM configuration.

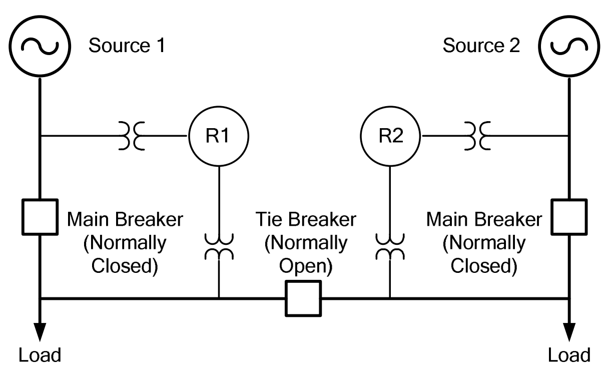


Fig. 12 Main-Tie-Main One-Line Diagram

If Source 1 is lost, the main breaker opens to isolate Bus 1 from Source 1. Next, the tie breaker closes to feed Bus 1 from Source 2. Some MTM schemes also implement automatic restoration, which returns the scheme to its original configuration when the source voltage returns. Two ways to return to the normal configuration are open transitions and close transitions.

In an open transition, once Source 1 returns, the tie breaker opens. Next, the main breaker associated with Source 1 closes. The disadvantage to open transitions is that load is dropped to return the scheme to normal. However, synchronism check is not required, and the two sources are never tied together.

A more common implementation of automatic restoration is the close transition. In a close transition, the main breaker is closed when Source 1 becomes healthy. Next, the tie breaker is opened. The advantage of the close transition is that no load is dropped to return the system to normal configuration. However, a synchronism check is required to close the main breaker, ensuring the two sources are synchronized. Also, the two sources are tied together for a very brief time before the tie breaker is opened.

In this field example, an industrial facility is having trouble with the MTM scheme going back to the normal configuration after the source returns. The customer implements close transitions for the automatic restoration. The MTM scheme uses relay-to-relay communication with internal relay logic. A Sequential Events Recorder (SER) report was retrieved from both relays in the scheme. The SER data, a very powerful tool in troubleshooting logic schemes, provide a time-tagged status of all the measured and internal logic elements.

In this event, Source 1 is lost. Relay R1 then opens the Source 1 main breaker. After 2 seconds, the tie breaker is closed by the right-side relay (R2), and both buses are fed from the Source 2 breaker. After Source 1 becomes healthy again, R1 should close the source main breaker, but it does not. The abridged SER data from R1 are shown in Fig. 13.

```
08:07:44.589  SV9T    Deasserted   Left Drop in Voltage – Begin Timer
08:07:44.597  SV1     Asserted     Timer Begins
08:07:46.595  SV1T    Asserted     Loss of Voltage for 2 Seconds
08:07:46.595  OUT102  Asserted     Trip Left Main Breaker
08:07:46.649  IN102   Deasserted   Left Main Breaker Open

08:07:47.798  SV9T    Asserted     Left Source Healthy

08:07:48.843  IN102   Asserted     Tie Breaker Closed

08:07:48.843  SV12T   Asserted     Right Main Closed, Tie Closed

08:07:48.851  RMB3A   Deasserted   Right Source Unhealthy
08:07:54.932  RMB3A   Asserted     Right Source Healthy for 6 Seconds

25A1 asserts for very short time intervals

11:14:45.675  25A1    Asserted
11:14:45.675  SV5     Asserted
11:14:45.829  25A1    Deasserted
11:14:45.829  SV5     Deasserted
11:23:48.826  25A1    Asserted
11:23:48.826  SV5     Asserted
11:23:49.080  25A1    Deasserted
11:23:49.080  SV5     Deasserted

After 3 hours and 38 minutes from initial source healthy, tie closes

11:45:20.612  25A1    Asserted     Source 1 and Source 2 In-sync
11:45:20.612  SV5     Asserted
11:45:22.617  CLOSE   Asserted     Close Issued to Left Main Breaker
11:45:22.692  IN101   Asserted     Left Main Breaker Closed
11:45:22.792  OUT104  Asserted     Open Issued to Tie Breaker
11:45:22.850  IN102   Deasserted   Tie Breaker Opened

Normal State
```

Fig. 13 SER Report Captured From Relay R1

The following shows a brief description of the main breaker close logic for automatic restoration:

25A1 = sources are synchronized
SV9T = left-side voltage is healthy
RMB3A = right-side voltage is healthy

SV5 = 25A1 * SV9T * RMB3A (25A1 AND SV9T AND RMB3A)
SV5PU = 120 cycles
Close = SV5T
OUT101 = close Main 1 breaker

For the Source 1 main breaker to close for automatic restoration, the two sources must be healthy and synchronized (within 15 degrees) for 2 seconds. However, the voltages do not stay synchronized long enough to close the main breaker. Once the source is healthy for at least 3.5 hours, the synchronism element finally asserts for the minimum required time of 2 seconds, which allows the main breaker to close. After the main closes, the tie opens as expected, putting the MTM scheme back into normal configuration.

Solution: The constant pickup and dropout of the synchronism element (25A1) indicates that the synchronism angle check qualification settings are right on the edge of what is deemed an acceptable window. For over 3 hours, the facility was vulnerable to total power loss while the synchronism element was on the edge of operating. Using this information, the facility engineer changed the synchronization window setting from 15 to 20 degrees.

D. Line Current Differential Relay Commissioning Discovers Different Primary Phasing

A short transmission line connects two substations owned by two separate operating companies. The line is protected by line current differential relaying. The differential principle simply states that, for normal load conditions or external faults, the current flowing into the line is equal to the current flowing out of the line. Fig. 14 shows a one-line diagram indicating that the 87L trips (operates) for faults on the line but restrains for external faults.

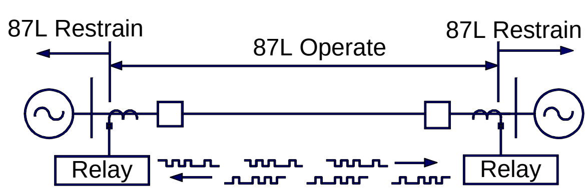


Fig. 14 Line Current Differential One-Line Diagram

To commission the protective relaying, the line was energized with a small amount of external load. In this case, we would expect the local currents to be 180 degrees out of phase with respect to the remote currents [4].

Fig. 15 shows a screen capture of the currents present during commissioning.

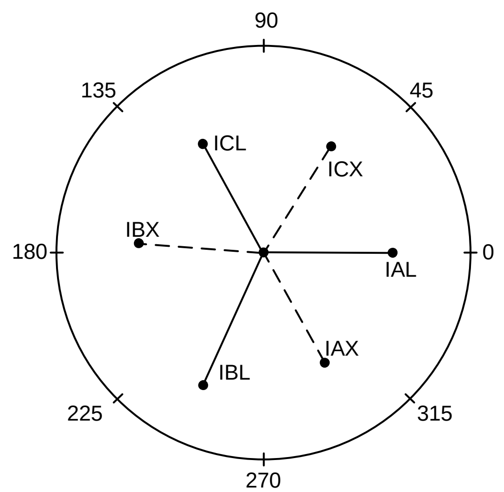


Fig. 15 Phasor Currents During Commissioning

IAL, IBL, and ICL represent the local relay currents; IAX, IBX, and ICX represent the remote relay currents. We can see that phase rotation and magnitudes appear correct (ABC). However, we discover that the local (L) relay currents are assigned ABC and the remote (X) currents are assigned BCA. That is, IAL is 180 degrees out of phase with IBX, etc.

Solution: The phases must be reassigned so that the local and remote input currents are the same (ABC, ABC). If we cannot reassign the primary power system phases, we must reassign the phases on the CT secondaries at one end of the line. This change should be well documented and displayed to avoid future confusion (e.g., the relay indicates an A-phase-to-ground fault when it is actually a power system B-phase-to-ground fault).

E. Line Current Differential Trip Is Prevented

Two line current differential relays were installed to protect a section of cable in an industrial facility. The primary system was commissioned and put in service, while the backup system was connected to the CTs without the trip output connected. The backup system was not placed in service due to time constraints during commissioning.

A month later, technicians went back on site to commission the backup relays. When they arrived, they observed the backup relay targets showed that a C-to-A-phase fault had occurred, and the relay had called for a trip via the line current differential elements. The primary system, however, showed no signs of a trip operation. Because both systems operated based on the same line current differential scheme, why did the backup system call for a trip while the primary system did not?

There were no events available from the primary system. The backup system event is shown in Fig. 16.

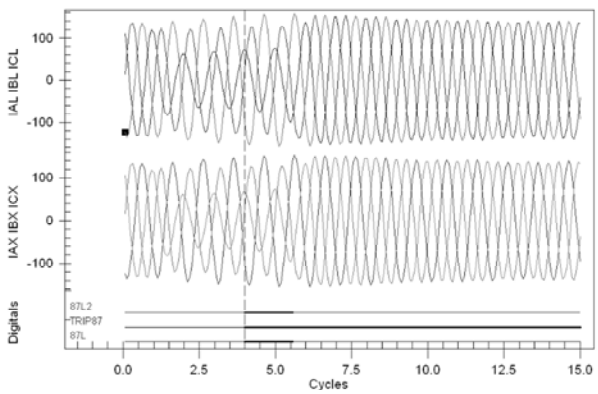


Fig. 16 Backup Relay Currents and Outputs During the Event

Fig. 16 shows low current on Phase B at each terminal for 4.5 cycles. The negative-sequence differential element (87L2) asserts and produces the trip condition. IAL, IBL, and ICL are the currents seen at the local relay terminal, while IAX, IBX, and ICX are the currents seen at the remote terminal. On initial inspection, this does not appear to be a system fault. A reduction of current is more likely related to a loss of load.

In this case, the reduction on Phase B current caused the line current differential to operate. If the trip output had been connected on the backup relay, the breaker would have tripped, and load would have been lost. To further analyze this event, we examine the prefault phasors, as shown in Fig. 17.

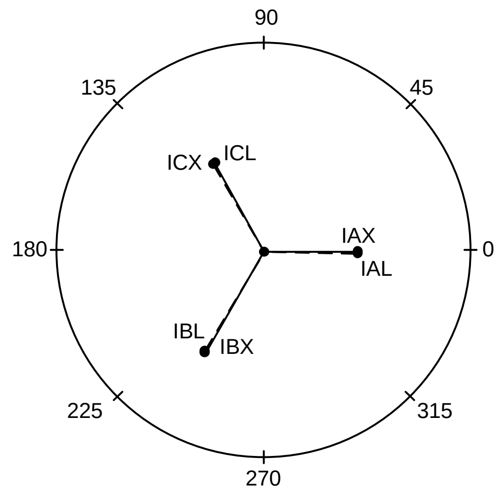


Fig. 17 Local (IAL, IBL, ICL) and Remote (IAX, IBX, ICX) Phasor Currents

As discussed earlier, the currents should be equal in magnitude and 180 degrees out of phase for normal load. Thus, the polarity on one terminal of the line current differential is incorrect.

It appears the incorrect CT polarity is the cause of the relay output assertion. Two questions remain: Why did the relay not operate for normal load flow? Why did the relay operate for this system unbalance?

In this particular relay, five differential elements operate in the relay independently: Phase A, Phase B, Phase C, negative sequence, and zero sequence. The phase element pickup (Phases A, B, and C) is set to 6 A secondary (about 2400 A primary) for this system, with a 400 to 1 CT ratio. The negative- and zero-sequence elements are set to 0.5 A secondary (about 200 A primary).

From the event, we see that the current is approximately 135 A primary on each phase, or 0.34 A secondary. Under normal load conditions, the difference current evaluates to 0.34 A + 0.34 A = 0.68 A, well below the minimum operating current of 6 A. Eventually, a higher magnitude external fault would cause an incorrect trip.

Why did the relay operate for this system unbalance?

As mentioned earlier, the relay operated on a negative-sequence differential element. The minimum pickup for this element is set at 0.5 A secondary. Table I shows the negative-sequence difference current, |IR+IL|, during Cycle 4 of the event at 283 A (or 0.7 A secondary, which is greater than the 0.5 A pickup setting).

TABLE I
NEGATIVE-SEQUENCE DIFFERENTIAL
CURRENT AT TIME OF RELAY TRIP

	$\frac{\lvert \mathbf{I_R} \rvert}{\lvert \mathbf{I_L} \rvert}$	$\angle \frac{\lvert \mathbf{I_R} \rvert}{\lvert \mathbf{I_L} \rvert}$	$\lvert \mathbf{I_R} + \mathbf{I_L} \rvert$
Cycle	**Magnitude**	**Angle**	**Total**
4.000	0.97	358.78	283.21
4.063	0.99	359.91	283.04
4.125	0.96	0.46	280.27
4.188	0.98	0.08	276.01
4.250	0.98	358.33	283.43
4.313	0.98	0.59	283.83
4.375	0.97	359.38	280.36

Solution: A misoperation was avoided because this "trip" occurred while the relay was not in service. The root cause is an incorrect CT polarity on one terminal of the differential. This also could have been found using metering or event data from the relay while the line was energized.

F. Differential Relay Trips for Motor Starts

A 17,500 hp three-phase motor operating at 13.8 kV is experiencing occasional motor start trips via the motor differential relay. The trip event history is shown in Table II.

TABLE II
TRIP EVENT HISTORY

Date	Time	Targets	Trip
06/02/06	20:20:28	87 C Phase	Yes
08/19/06	15:03:29	87 C Phase	Yes
11/22/06	07:05:27	87 C Phase	Yes

Three trips occurred during the span of nearly six months. However, after each of these trips, the motor was restarted successfully. What is causing the motor differential relay to misoperate?

Fig. 18 shows the unfiltered currents seen by each CT input of the differential during motor start.

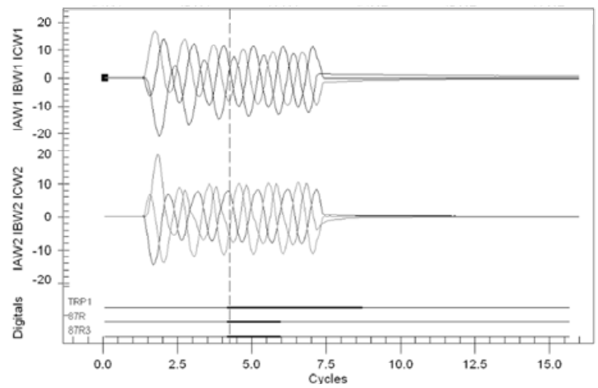


Fig. 18 Unfiltered Motor Start Currents

In this event, only one of three differential elements, 87R3, operates, which corresponds to a Phase C differential operation. Fig. 19 shows the three-phase currents from each winding.

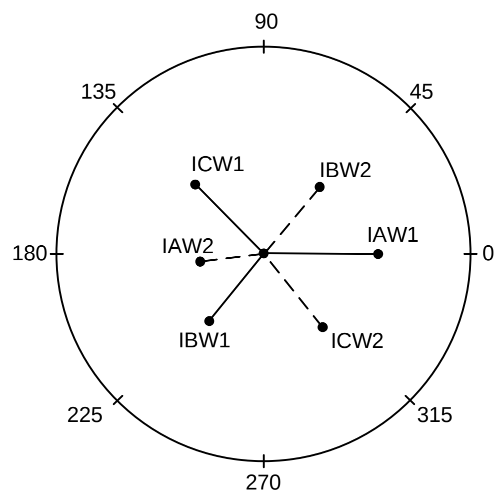


Fig. 19 Motor Current Starting Phasors

Fig. 19 shows that the phase angle between the current inputs appears to be correct since each Winding 1 phase current is 180 degrees out of phase with the corresponding Winding 2 current. To verify the findings from the event report, the proper CT ratios and polarity were reviewed on site, and no errors were found. If the wiring is correct, what caused the motor differential mis-operation?

Referring to Fig. 18, note that there is some dc offset current during the first few cycles of the motor start. DC offset occurs based on the angle of the applied voltage. DC offset is highest when the voltage waveform is at a zero crossing and lowest when the voltage is at a peak.

Since the relay operated for a Phase C differential, we examine the Phase C winding currents.

Unfiltered Winding 1 and Winding 2 Phase C currents are shown in Fig. 20.

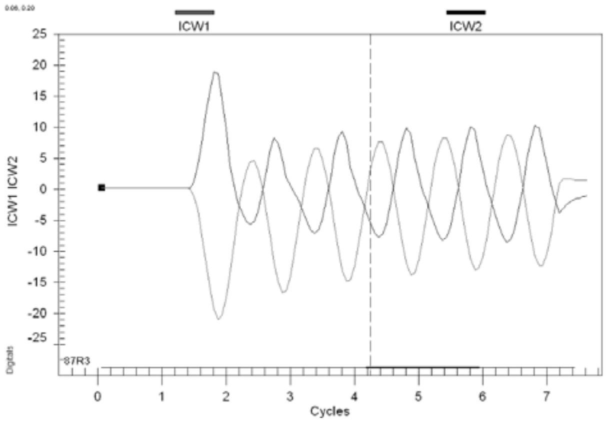


Fig. 20 Unfiltered Phase C Motor Start Current

The Phase C CT connected to ICW2 appears to saturate during the decay of the dc offset, while the Phase C CT connected to ICW1 has very little saturation.

Since the relay operating quantities are based only on the 60 Hz signal, we next examine the filtered currents, as shown in Fig. 21.

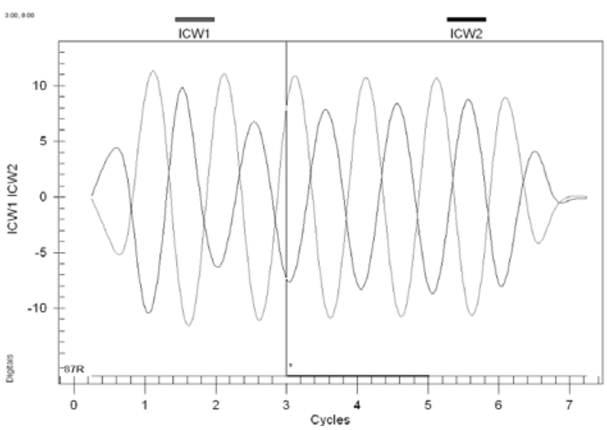


Fig. 21 Filtered Phase C Motor Start Current

Note that these currents should be equal in magnitude and 180 degrees out of phase. However, we observe a phase angle shift and magnitude reduction in the saturated CT current.

To avoid future misoperations, we evaluated some possible solutions. One solution would be to raise the differential slope setting. Analysis indicated that a slope of 60 percent or greater would avoid future misoperations. However, setting the slope this high would desensitize the relay for some internal faults. Another solution is to lower the second-harmonic blocking feature of the relay. The differential relay uses harmonics for restraint or blocking. Since CT saturation was involved, we evaluated the harmonic content of the Phase C current. The Winding 2 current harmonic analysis is shown in Fig. 22.

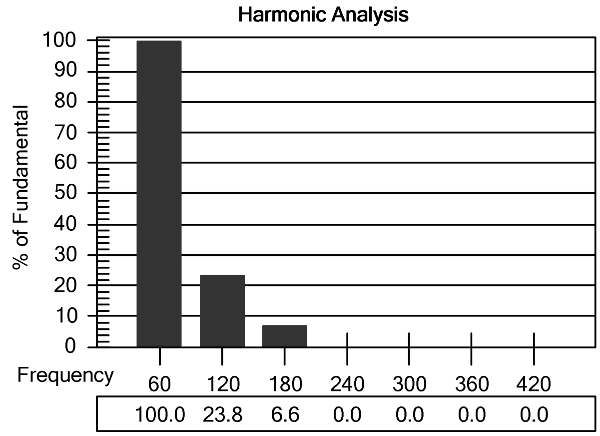


Fig. 22 Phase C Harmonic Current at the Time of the Trip

Fig. 22 shows that the second-harmonic content is greater than 23 percent of the fundamental current. The second-harmonic block setting could be lowered from its setting of 15 to 12 percent, for example. This would make the relay more secure during CT saturation but has the disadvantage that it could delay tripping if CTs saturate during an actual fault.

Table III is a summary of the operating and restraining quantities as well as the calculated slope and second-harmonic content of the Phase C CT.

TABLE III
OPERATING AND RESTRAINING QUANTITIES

Date	I_{op} pu	I_{res} pu	I_{op}/I_{res} %	2nd Harmonic %
06/02/06	0.91	1.80	51	17
08/19/06	0.96	1.73	55	24
11/22/06	0.94	1.80	52	15

Possible Solutions: The ideal solution is to use CTs that are rated to avoid saturation. However, if this is not possible, the best solution is to raise the slope setting (e.g., raise to 60 percent). The relay would be somewhat less sensitive but would still detect internal faults. Another solution is to reduce the second-harmonic blocking setting (e.g., from 15 to 12 percent). This setting prevents the differential element from operating if the ratio of second-harmonic current to fundamental current is greater than 12 percent. However, this setting could delay tripping if the CTs saturate during an actual fault, so this solution should be applied with caution.

G. Phase Directional Overcurrent (67) Trips for Remote Fault

Two sources supply power at the intertie point between a utility and an industrial facility. The power system is an interconnected network, and the transformer low-side breakers are operated normally closed. Therefore, directional overcurrent relays (67P-1, 67P-2) are applied to detect and trip for faults on the power system, as shown in Fig. 23.

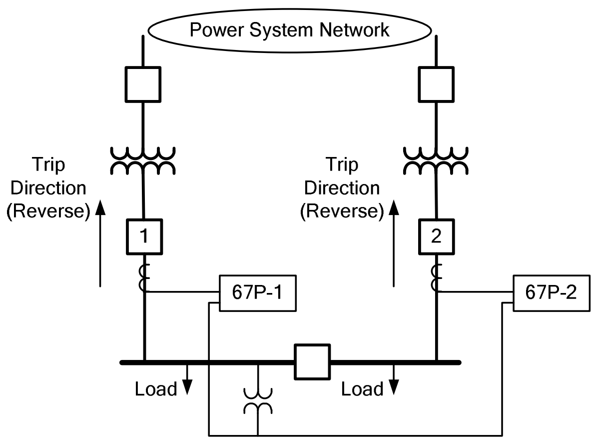


Fig. 23 System One-Line Diagram

A fault occurs on the utility system, which eventually causes the loss of both sources. Fig. 24 shows a screen capture of the event report from Relay 67P-2 that helps to find the root cause and prevent future misoperations.

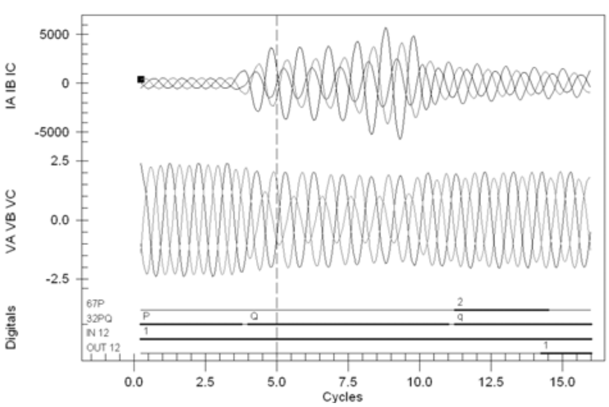


Fig. 24 Event Report From Relay 67P-2 Shows System Fault and Eventual Relay Trip

From the event screen capture, note that 67P-2 picks up and trips in 3 cycles. The directional element 32PQ initially declares forward (P and Q), then reverses (q).

The reversal occurs after the adjacent Line 1 trips. Fig. 25, Fig. 26, and Fig. 27 show the load current direction and directional element reversal during this event.

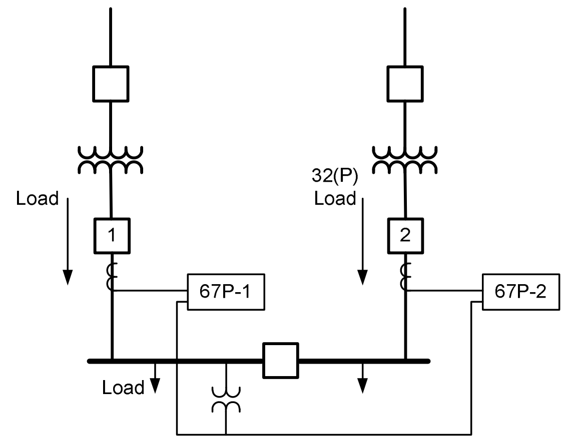


Fig. 25 State of Power System Before Fault

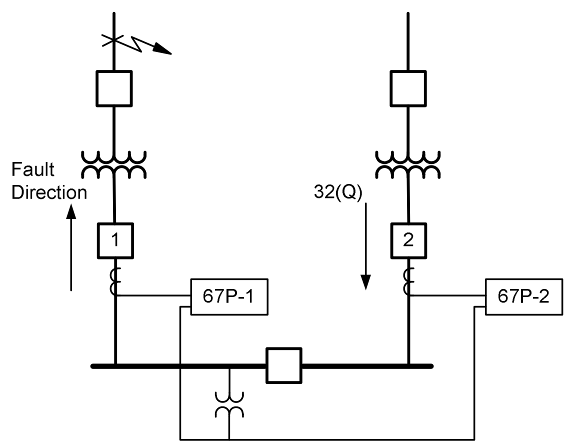


Fig. 26 Initial Fault Detected by 67P-2 in the Nontrip Direction

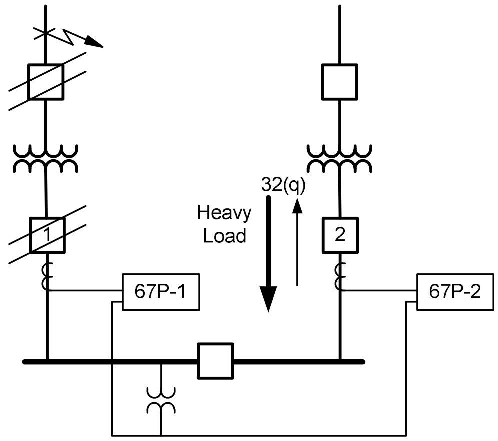


Fig. 27 Breaker 1 Trips but 67P-2 Directional Overcurrent Relay Detects Persistent Fault and Eventually Trips

Why did the relay trip? Relays 67P-1 and 67P-2 use a phase directional element that has two elements working together: positive sequence (32P) and negative sequence (32Q). Negative sequence is used for any unbalanced fault (e.g., phase to phase) and positive sequence for three-phase faults.

Significant point: In this relay design, the negative-sequence element has priority. If enough negative-sequence current exists, the directional decision is controlled by the negative-sequence directional (32Q or 32q) elements. Thus, when Breaker 1 opens and the negative-sequence element reverses, the 67P-2 relay, set to assert for system faults, picks up and trips, even though the load current is in the nontrip direction.

Solution: The original settings use: TR = 67P2T.

Element 67P2T is a phase directional overcurrent element that combines the tripping decision (positive and negative sequence both actuate 67P2T).

The solution is to separate the tripping decision by:

- Modifying 67P2T to trip for only three-phase faults (use positive sequence only).
- Introducing a negative-sequence overcurrent element (67Q2T) to trip only for unbalanced faults (use negative sequence only).

We achieve this with the following setting changes:

- 67P2TC = R32P (R32P “torque controls” 67P2T to trip for only reverse three-phase faults)
- TR = 67P2T + 67Q2T (add 67Q2T to trip for unbalanced system faults)

H. Motor Trips During Startup on Load Jam

During the startup of an induction motor in an industrial facility, a motor relay removes the motor from service for a load-jam trip. A soft starter is used to help reduce the amount of current the motor draws during startup and is in series with the motor contactor. Once the motor is up to speed, a contactor bypasses the soft starter to remove the starter from the circuit. During this startup, the motor relay tripped 1 second after the soft starter was enabled and before the bypass contactor was closed. Why would the motor trip on load jam for a motor start? Fig. 28 shows a one-line diagram for the motor and soft starter configuration.

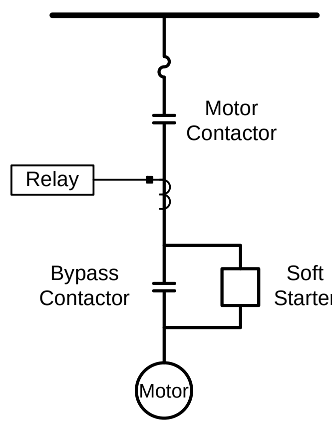


Fig. 28 One-Line Diagram

While the motor is running, a load-jam element is used to detect a mechanical failure that jams the motor and prevents or restricts the rotor from turning. If the rotor is prevented from turning while the motor is energized, large currents begin to flow in the motor, and thermal damage of the motor will occur. The load-jam element is only enabled after the motor has completed startup, because the starting currents will likely exceed the setting threshold of the load-jam element.

In this event, the motor has not completed starting, so a load-jam trip should not occur. The relay captures motor start reports that track the three-phase current during the time period of a motor start. The motor start report for this event is shown in Fig. 29.

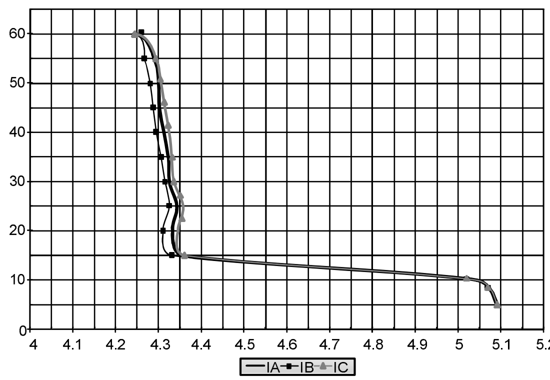


Fig. 29 Motor Start Report

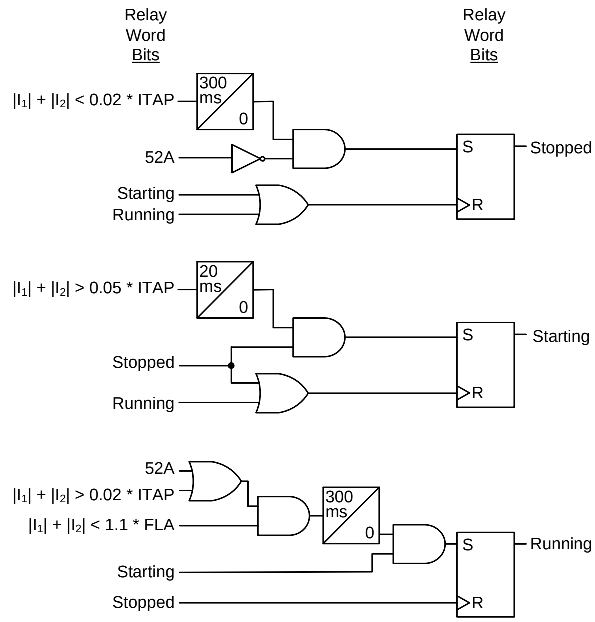
In this report, the x-axis represents multiples of FLA (full load amperes) for the current of each phase. The y-axis represents time in seconds. During this attempted motor start, the FLA did not drop below 4.2 FLA until the 1-second mark, which is the instant the relay called for a trip. The motor report shows the amount of current seen by the relay but does not explain the relay trip. To further investigate the event, the SER report is examined (Fig. 30).

#	DATE	TIME	ELEMENT	STATE
57	01/01/2100	05:32:41.672	MOTOR_BREAKER	CLOSED
56	01/01/2100	05:32:43.051	MOTOR_STOPPED	ENDS
55	01/01/2100	05:32:43.051	MOTOR_STARTING	BEGINS
54	01/01/2100	05:32:43.056	TIME_BSTARTS_LO	PICKUP
53	01/01/2100	05:32:43.056	MOTOR_RUNNING	BEGINS
52	01/01/2100	05:32:43.056	MOTOR_STARTING	ENDS
51	01/01/2100	05:32:44.068	LOAD_JAM_TRIP	PICKUP
50	01/01/2100	05:32:44.068	TRIP	Asserted
49	01/01/2100	05:32:44.093	MOTOR_BREAKER	OPEN

Fig. 30 Motor Start SER Report

The first event in the SER report is the closing of the main contactor. After 1.4 seconds pass, the relay indicates that the motor is starting. Only 5 milliseconds after the motor has been in the start state, the relay declares the relay in running state. Based on the motor starting event shown earlier, we know that the motor start takes at least 60 cycles. Once the relay declares the motor is in the running state, a load-jam trip occurs 1 second later. This 1-second time delay corresponds to a relay setting. At this point, it is apparent that the relay incorrectly declared the motor to be running, which activated the load-jam trip elements.

To see how the relay determines the motor starting, running, and stopped states, the relay operational logic must be studied. The logic that defines these three states is shown in Fig. 31.



Note: FLA = Full Load Current in Secondary Amperes
ITAP = Phase CT Secondary Rating, 1 A or 5 A
I_1 = Positive-Sequence Motor Current in Secondary Amperes
I_2 = Negative-Sequence Motor Current in Secondary Amperes

Fig. 31 Motor State Selection Logic

Since the SER data indicate the transition from the starting state to the running state occurred too quickly, the logic for the running state is reviewed. The running state is selected by the relay if the motor contactor is closed (52A), the magnitudes of the positive- and negative-sequence currents are less than 1.1 • FLA for 300 milliseconds, and the relay is currently in the starting state. Generally, this logic would indicate that the starting current has subsided and the motor is up to speed.

In this installation, however, when the motor contactor closes, no current flows until the soft starter is engaged. Since the time between the motor contactor closing and the soft starter engaging is greater than 300 milliseconds, the running logic times out and alarms, waiting only to see the relay go to the starting state. Once the relay enables the starting state when the soft starter is engaged, the running state is enabled immediately in the next processing interval. When the relay enables the running state, the load-jam elements activate and trip the motor.

Solution: There are two ways to correct this problem. The first is to actuate the soft start less than 300 milliseconds before closing the motor contactor. The second option is to disconnect the motor contactor status from the relay. If 52A is not asserted, the relay will rely only on current to detect the motor state.

I. Motor Start Reports Validate Relay Settings

Induction motors, particularly high-inertia motors, are operated at near capacity in some facilities. At one facility, the engineers used motor start reports from relays to maximize output without jeopardizing the protection [5].

The following screen capture shows a motor start report for a 350 hp blower motor. For a motor acceleration time of about 10.5 seconds, approximately 33 percent of the motor thermal capacity (%TCU) was used. The engineers used these data to validate the relay settings.

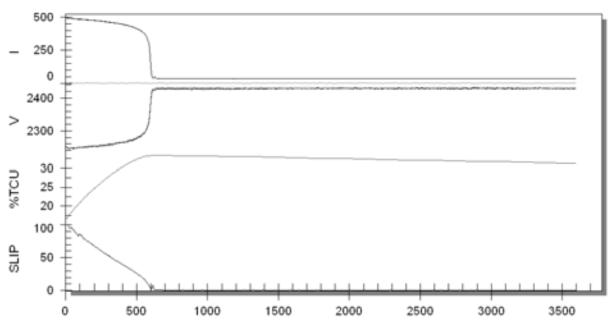


Fig. 32 Motor Start Report for a Blower Motor

OTHER IMPROVEMENTS

Event report analysis is useful for finding the root cause of faults and evaluating the performance of protective elements after a disturbance has occurred. There are other monitoring features in digital protective relays that are useful in preventing disturbances related to equipment failure and can be used to perform preventative maintenance. Monitoring equipment can reduce equipment downtime if a potential failure is found before it occurs.

Not only can failures take days or weeks to repair, but also extended temporary system reconfigurations to restore load can make the system less reliable than the normal system configuration. These extended temporary system configurations can make the facility more vulnerable to total power loss for subsequent faults.

Transformer and breaker failures can lead to extended loss in downtime due to system damage and lead-time for replacement parts. Monitoring with digital relays allows the user to predict when maintenance is needed and to plan in advance the ideal time to perform necessary repair and maintenance. Some of the monitoring features included in digital relays are highlighted in the next subsections, including breaker monitoring, transformer monitoring, dc battery monitoring, and loss-of-potential indication.

A. Breaker Monitoring

Circuit breaker monitoring can be used to detect contact wear and provide a breaker alarm or prevent reclosing. A major benefit of the breaker contact wear monitor is that the relay can determine the amount of cumulative current interrupted and use this cumulative value to calculate the overall contact wear on a per-phase basis. If the contact wear approaches 100 percent, the chances of the breaker not interrupting fault current in a timely fashion increase, which leads to an increased chance of breaker failure. When a feeder breaker fails, all adjacent breakers must be tripped to clear the fault, including the main load breaker. This can lead to power outages for an entire facility rather than just the faulted feeder. If contact wear can be detected early, the breaker can be maintained without any loss of service.

The breaker wear monitor also indicates which phases see the most faults. For example, if a breaker shows a high percentage of wear on Phase A relative to Phases B and C, there may be some merit in exploring why that phase has had more operations than the other two phases. Perhaps the buswork is near to some fault hazard that makes a certain phase more prone to faults.

A shortcoming with the breaker wear monitor is that it is difficult to apply on existing breakers, because the existing operational history is not easily obtained. However, on new breaker installations, breaker monitoring is easy to set up by using the supplied breaker damage curves.

Fig. 33 shows an example of a breaker monitor report available from the relay that includes the total amount of interrupted current, number of operations, and percent contact wear on a per-phase basis.

```
FEEDER 1  Date: 11/25/08  Time: 16:07:47.403
STATION A

Rly Trips*     6
 IA=  62.2    IB=    0.0    IC=    0.0 kA

Ext Trips*     0
 IA=   0.0    IB=    0.0    IC=    0.0 kA

Percent wear:  A= 19  B=  0  C=  0

LAST RESET 11/25/08 16:04:15
```

Fig. 33 Example Breaker Contact Wear Report

B. Transformer Monitoring

Transformer through-fault monitoring can be used to determine maintenance intervals for transformers as well as predict the expected life of the transformer. External transformer faults cause a large amount of current to flow through the transformer, which then produces large forces in the transformer windings. The forces during a fault will physically shift the windings and can lead to an accelerated breakdown of insulation between the windings. Over the life of a transformer, through-fault damage is cumulative and can lead to a shorter than expected service life. Accurately tracking the current during the faults, as well as fault duration, allows the relay to calculate cumulative I^2t damage. This can be compared to the transformer damage curve to determine when the windings need to be removed and replaced.

Note that applying through-fault monitoring on an existing transformer makes it nearly impossible to determine the existing I^2t damage on the transformer. However, new transformers can easily have through-fault monitoring enabled with the use of the transformer damage curves specified in IEEE C57.12.00-2000. These curves detail the I^2t value at which damage will begin to occur. Generally, an alarm asserts when a preset I^2t value is reached to inform the user when the transformer has exceeded the damage curve.

Fig. 34 shows an example through-fault report available from a digital relay.

```
XFRM 1                   Date: 06/17/06  Time: 18:59:49.130
STATION A

Number of Through Faults: 10 Last Reset: 02/10/04 19:56:22
Winding 1 Total I-squared-t (kA^2 seconds, primary):
          A-phase      B-phase      C-phase
          147.800      303.500      237.900

#     Date       Time      Duration    IA    IB    IC
                          (seconds)  (A. primary max)
  1 02/14/04 18:59:22.244   5.002     241  4158   260
  2 02/11/04 11:37:55.495  30.834     220   241   451
```

Fig. 34 Example Transformer Through-Fault Report

C. DC Battery Monitoring

One of the most vital parts of a protection system is the battery. The battery is the “heart” of the protection system that powers relays, trips breakers, and provides backup power when the ac station service is lost. If the dc system fails or is incapable of tripping a breaker, severe system damage can occur. Digital relays can monitor the dc voltage to verify the system is healthy using a dc battery monitor. If the dc voltage sags or swells for a certain amount of time, an alarm asserts, indicating an abnormal battery condition. An abnormal dc condition can also be used to prevent reclosing, which will prevent any subsequent trip operations if the battery is unhealthy.

Event reports also contain the dc voltage seen by the relay during fault events. This makes it easy to view the dc voltage during trip operations to see if the battery voltage sags. Severe or prolonged sags in dc voltage during a breaker operation are also an indication the battery is unhealthy.

D. Loss-of-Potential Detection

Loss-of-potential detection is valuable in schemes that rely on voltage for proper operation. For example, directional elements that rely on voltage can be turned off or made nondirectional when a loss-of-potential condition is detected. Without loss-of-potential detection, directional elements will become unreliable.

CONCLUSIONS

Using event reports and other information from relays improves power system reliability. Capturing and understanding field events allow facility engineers to find the root cause of electrical problems and reduce downtime, thus reducing loss-of-production costs.

From field data, facility engineers and technicians were able to:

- Correct reversed polarity on a generator differential relay.
- Validate correct wiring on a refurbished motor.
- Change synchronism-check angle settings to allow automatic restoration of an MTM scheme.
- Identify that primary phase conductors were assigned differently at each end of a transmission line.
- Correct secondary CT wiring on a line current differential application.
- Improve relay settings to avoid differential relay trips during motor starting.
- Improve directional overcurrent relay security at the utility and industrial interface.
- Eliminate spurious motor trips in a soft start application.
- Use motor start reports to validate relay settings.

Monitoring breakers, transformers, dc sources, and other metered quantities all contribute to improving the performance of the electrical power system.

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