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303

WHEN NUMERICAL GENERATOR PROTECTION WITH CONVENTIONAL CT'S MAY LET YOU DOWN

P J Hindle

PB Power Ltd, Newcastle, UK

INTRODUCTION

This paper first of all highlights some key differences between numerical generator differential protection schemes and former analogue relay schemes in terms of performance with conventional current transformers (CT's). Potential protection stability problems are then considered. These could be latent and might only become apparent during critical black start operations of some types of large gas turbine generating plant or during other plant operations with emergency generators.

The relative ease and speed with which large gas turbine generators can be started from an emergency source of power means that they are often in the frontline line of the strategy to recover a power system after a major shutdown. Thus, the effects of any hidden protection stability problems that result in tripping during a black start sequence would be particularly serious.

The analysis of a real failure incident during black-start proving trials for a large combined cycle power plant is summarised in this paper. The limitations of certain established relaying principles are highlighted – as is the importance of conducting such trials. The possible under-specification of CT requirements by relay manufacturers and possible insufficient testing of protection relay designs to confirm that they will be fit for purpose under all critical plant operating conditions is also mentioned.

BACKGROUND

Stator winding differential protection is widely applied to generators with ratings in excess of 1 MVA. The aim is to provide rapid tripping in the event of a multiphase stator winding or connections fault. The current sensitivity of the protection must be such that it will respond to phase faults at any credible location within the machine. It should also operate without any intentional time delay. On the other hand, it must be stable for all load, through fault and transient stator current conditions. Any protection malopertion during a power system disturbance that may already be threatening system security or during critical plant operation can have serious consequences.

EVOLUTION OF DIFFERENTIAL PROTECTION

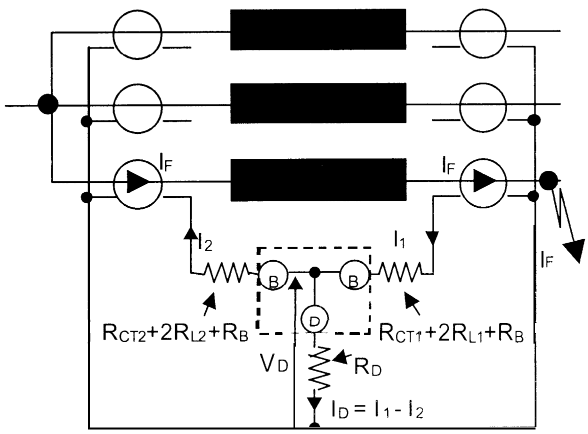

Figure 1 Analogue Circulating Current Differential Protection Application

Early protection schemes were based on the Merz-Price circulating current principle, where the secondary currents from phase CT's located on either side of each phase winding are circulated from one CT to the other through interconnecting leads. Current-operated relay elements are connected across the CT leads to provide a path for difference currents to flow, as summarised by Figure 1. An in-zone fault is recognised by the detection of a significant difference current.

As is well known and well documented, practical circulating current protection schemes require stabilisation for external faults or disturbances that cause CT saturation. It is not feasible to avoid transient CT saturation under all circumstances.

Even where CT' s are of similar design and where the leads between each set of CT' s and the differential relay are balanced, it is quite likely that the protection CT' s will not saturate to the same degree at the same time. With differences in initial remnant flux conditions alone, there is the possibility of transient asymmetric CT saturation. The resulting transient difference in CT secondary currents could result in unwanted differential relay operation unless special measures are employed to stabilise the protection for such conditions.

CONSIDERING TRANSIENT CT SATURATION

General Consideration

To simplify consideration, it will initially be assumed that an unsaturated CT has infinite magnetising impedance and that its secondary circuit is entirely resistive (no secondary transient effects). In this case, the CT core flux variation required to transform a <u>fully offset</u> primary fault current waveform is expressed as follows.

$$f_{CT} = \frac{\hat{I}_F R_S}{wN^2}\left[-Sin wt + \frac{wL_P}{R_P}\left(1 - e^{-\frac{R_P t}{L_P}}\right)\right]$$

$$\hat{\Phi}_{CT} = \frac{\hat{I}_F R_S}{wN^2}\left[1 + \frac{wL_P}{R_P}\right] = \frac{\hat{I}_F R_S}{wN^2}\left[1 + \frac{X_P}{R_P}\right]$$

$Where:$

$$i_F = \hat{I}_F\left[Sin\left(wt - \frac{p}{2}\right) - e^{-\frac{R_P wt}{X_P}}\right]$$

$L_P =$ primary system inductance

$X_p =$ primary system reactance at ω

$R_P =$ primary system resistance

$I_F =$ primary RMS fault current

$i_F =$ primary instantaneous current

$R_S =$ secondary circuit resistance

$N =$ CT secondary turns

$w =$ system angular frequency

$\hat{\Phi}_{CT} =$ maximum CT core flux

$f_{CT} =$ instantaneous CT core flux

$t =$ time from fault inception

From the preceding equations, it can be appreciated that the primary system ratio X_P/R_P has a more significant influence on the level of flux that the CT must handle than the RMS level of fault current. A high level of core flux is required to transform any low frequency transient component of primary fault current. CT' s for high-speed protection must be oversized for transients.

Generator Applications

For generators, the maximum RMS level of through fault current contribution is limited to the order of just 5 times rated current. However, the generator circuit time constant could be of the order of 400 ms (X_P/R_P = 125 @ 50Hz). The slow decay of a generator current waveform transient offset leads to transient CT flux build-up even with a low RMS current. Unless physically impractical CT designs are applied, transient CT saturation for close-up through fault conditions and some other external disturbances cannot be avoided.

Two basic methods of stabilisation have historically been applied for differential protection. Some systems have either inherently or intentionally employed a hybrid combination of the two methods.

DIFFERENTIAL PROTECTION STABILISATION

Bias or Percentage Restraint Stabilisation

With reference to Figure 1, this protection principle is based on the automatic increase of the differential protection operating threshold as a function of the RMS magnitudes of currents from the protection CT' s.

There are many variations in the bias functions employed within relay designs from different manufacturers and there are variations in the ways in which different manufacturers depict the operating characteristics of their relay designs when relating Bias and Differential currents.

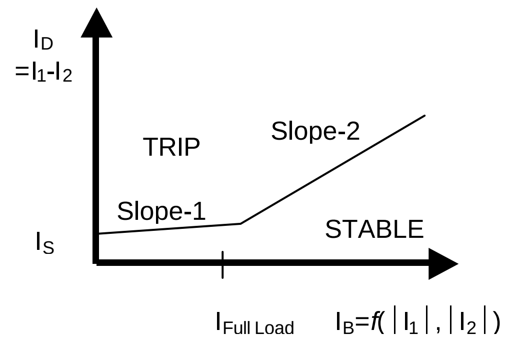

Figure 2 Biased Protection Characteristic

A tripping characteristic that is typical for modern numerical generator differential relays is depicted in Figure 2. This two-stage characteristic maintains differential protection sensitivity under load conditions whilst increasing stability under through fault conditions.

High Impedance Stabilisation

With reference to Figure 1, this protection principle is based on creating a relatively high impedance circuit for differential current. The impedance (R_D) must be sufficiently high to ensure that virtually all the secondary through fault current from an unsaturated CT will flow through the relatively low impedance path of a saturated CT circuit. The RMS spill current that might flow through the differential circuit must be kept below the operating threshold of the protection.

Any asymmetric CT saturation will only occur for part of each cycle of primary fault current. Thus, the resulting spill current will be highly non-sinusoidal and rich in harmonics. For this reason, the deployment of a differential current measuring element that is tuned to the nominal power system frequency will further enhance the through fault stability of the protection.

A worst possible scenario for maintaining protection through fault stability would be the complete saturation of one CT without any saturation of the other. Under such an assumed condition and with reference to Figure 1, the voltage developed across the differential current circuit can be expressed as follows, when CT_2 completely saturates:

$$V_D \approx \frac{I_F}{ratioCT} \times (R_{CT2} + 2R_{L2} + R_B)$$
$$When:$$
$$R_D >> (R_{CT2} + 2R_{L2} + R_B)$$

For assured stability of a tuned differential relay element, the following setting requirements should typically be satisfied:

$$SetV_R > V_D$$
$$SetI_R R_D > \frac{I_F}{ratioCT} \times (R_{CT2} + 2R_{L2} + R_B)$$
$$Stability:$$
$$I_F < \left[\frac{I_R R_D}{(R_{CT2} + 2R_{L2} + R_B)} \right] \times ratioCT$$
$$R_D > \left(\frac{I_F}{I_R \times ratioCT} \right) \times (R_{CT2} + 2R_{L2} + R_B)$$

To assure fast and reliable relay operation for internal faults, conjunctive tests with CT' s and relays have typically indicated that the minimum CT " kneepoint voltage" (V_K) should be at least twice the protection stability voltage setting (V_R).

For some high impedance differential protection applications, such as busbar protection, a high through fault current (I_F) with a low relay current setting (I_R) can demand quite a high differential circuit impedance (R_D) unless a high CT ratio is applied. Consequently, this will demand CT' s with a higher kneepoint voltage (V_K) in comparison to the CT' s required for biased differential protection. For differential protection of generators the converse is true.

Hybrid Stabilisation

As already indicated, transient saturation of generator protection CT' s may occur at a relatively low level of RMS through fault current when there is a sustained transient offset in the fault current waveform. This presents a problem for biased differential protection stability, since the bias effect is dependent on the level of RMS through fault current. The problem is compounded by the fact that the RMS level of generator fault current decays with time. Thus there are particular constraints on the degree of CT saturation that can be allowed for biased generator differential protection. Through conjunctive protection system tests or sophisticated simulation, a relay manufacturer should identify the differential relay stability constraints for all normal and transient operating conditions of a generator. The constraints should be expressed in the form of minimum CT requirements for the protection.

For high impedance differential protection, the problems just discussed do not exist. In fact, the relatively low level of through fault current (I_F) means that the required stability voltage setting for high impedance protection will not be very high. Often, it is incorrectly claimed that high-impedance protection demands CT' s with greater capacity than those required for biased differential protection. This is not the case for generator protection. In fact, it has been recognised for some time **[1]** that the CT requirements for traditional biased differential protection can effectively be reduced by the deliberate addition of differential circuit impedance. Some manufacturers have specifically provided hybrid schemes of this nature for generator differential protection.

With traditional biased differential relays, where the CT differential current is derived electrically, any inherent or added impedance in the differential relay circuit will divert some saturation spill current through the impedance loop of the saturated CT circuit. This will increase the overall bias current and it will decrease the differential current, thereby increasing the level of stability for a given set of CT' s

CHANGES WITH NUMERICAL PROTECTION

A typical difference between a discrete, analogue, generator differential protection scheme and a numerical scheme is the isolation between the different sets of CT secondary circuits, as illustrated in Figure 3. Here, the differential current and any bias current are derived mathematically, via the protection algorithm. The CT current data can also be processed for use by other integral protection function algorithms.

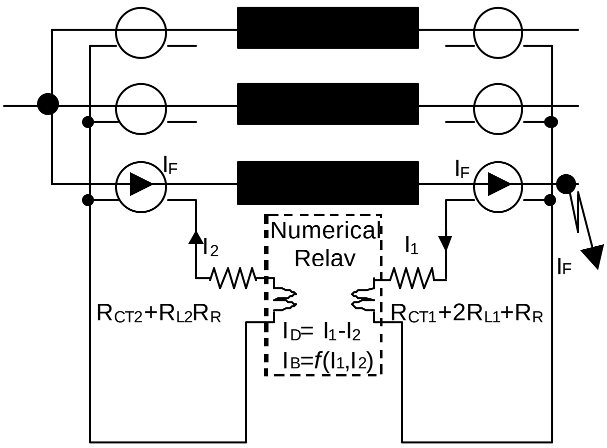

Figure 3 Numerical Differential Current Protection Application

The scheme illustrated in Figure 3 is not a circulating current differential protection scheme. There will be no stabilising diversion of differential current to bias current in the event CT saturation under through fault conditions. As a result, this form of protection will tend to have less stability than analogue biased differential protection. Thus, the bias for the protection may have to be increased or novel techniques will have to be used in order to achieve comparable stability to an otherwise similar analogue protection scheme.

BLACK START INSTABILITY OF NUMERICAL BIASED DIFFERENTIAL PROTECTION

Background

The primary electrical plant arrangements for a large gas turbine generating unit with a black starting capability are summarised in Figure 4. In this not uncommon arrangement, the alternator is used to start the turbine from a variable frequency, static start supply, instead of employing a dedicated turbine starter motor. The initial supply for the unit loads and for turbine starting would normally be drawn from the transmission grid, via the generator transformer. The starting supply would then be disconnected and the generator would then be synchronised to the grid via the generator circuit breaker (CB).

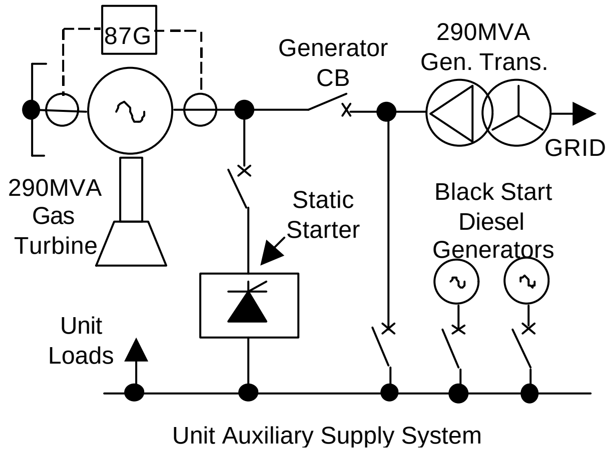

Figure 4 Gas Turbine with Static Starter

For black-starting the turbine, the diesel generators provide all the electrical power. Once started, it is a usual requirement that the generator should be able to energise the grid substation busbars. To achieve this, the generator CB must be closed onto the dead generator transformer. It is during such an operation that numerical biased generator differential protection can exhibit instability for this type of plant.

Records from Actual Case of Instability

During black start proving trials for the type of plant illustrated in Figure 4, the numerical generator differential protection issued a C-phase trip when the generator CB was closed. A second attempt was made to back-energise the transformer and there was a second differential protection trip involving the same phase. During subsequent protection system investigations, the CT current waveform samples that had been recorded by the relay on both occasions were downloaded for analysis.

When plotted, the recorded waveforms from the generator neutral-tail CT samples and from the terminal CT samples appeared to have only slight differences. The differences in current samples were derived and they are plotted in Figure 5. The neutral CT waveforms have also been plotted for reference. It can be seen that B-phase and C-phase differential currents appeared approximately 100 ms after the first back-energisation of the generator transformer. These differential currents must have arisen as a result of asymmetric saturation of the neutral and terminal CT' s on the B and C phases. This was despite the fact that the CT' s were all of similar design and despite the fact that the neutral and terminal CT lead lengths were symmetrical about the relaying point.

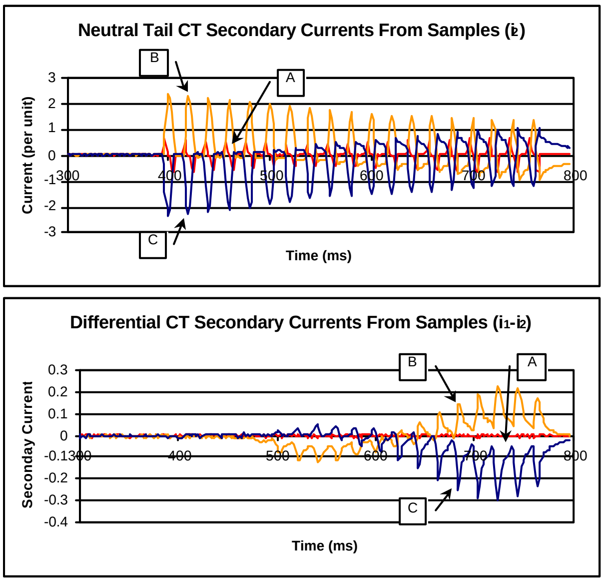

Figure 5 Neutral CT Secondary Waveforms and Derived Differential Waveforms

Analysis of Records

To asses the dynamic behaviour of the CT' s, the internal core flux levels were estimated in terms of voltage and these were compared with the tested CT kneepoint voltage level of 800 V RMS (IEC 60044-1 definition). The flux estimates were made by multiplying the CT secondary current samples by the sum of the CT secondary resistance, lead-loop resistance and relay input CT impedance. The resulting CT internal voltage samples were then integrated with time to obtain representations of internal flux variations.

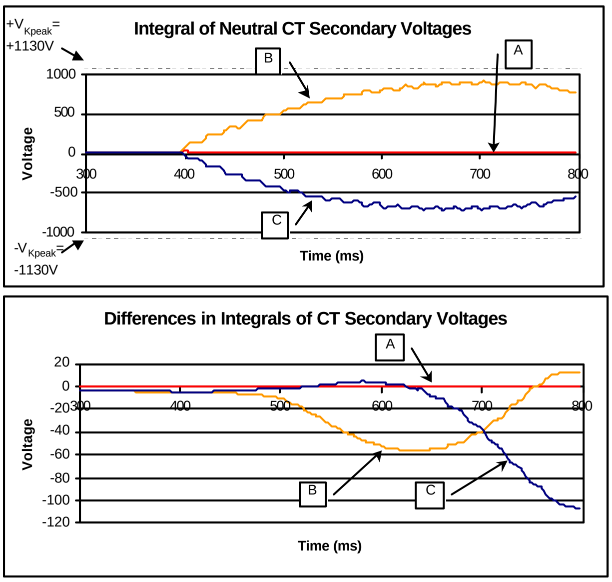

Figure 6 Representation of Neutral CT Core Fluxes in Relation to V_K and Differential Fluxes

Figure 6 depicts the results of flux estimation for the neutral CT' s and the differences in estimated flux variations between the terminal and neutral CT' s for each phase $(\phi_{terminal} - \phi_{neutral})$. It was assumed that all the CT' s were in a state of zero remnant flux prior to the records, although this was not likely to have been the case.

In Figure 6, it can be seen that there was unipolar flux build-up for the B and C phase CT' s, as a result of the primary waveform transient offsets (see Figure 5). The A-phase CT flux remained bipolar.

The fact that a positive flux difference arose initially for the C-phase CT' s (Figure 6), while handling a negative flux build-up, confirms that the terminal CT ran out of flux capacity before the neutral CT. With similar reasoning, this also appears to have been the case for the B-phase CT' s. It can also be seen from Figure 6 that the C-phase neutral CT ran out of capacity at a lower level of flux than the B-phase CT and that the neither appeared to have reached their theoretical flux capacity. This can only have been due to the effects of differing polarities and levels of remnant flux. The asymmetric loss of C-phase CT flux capacity resulted in coincident C-phase differential current (Figure 5). The low and variable frequency alternator starting currents seen by the CT' s may have had some influence on their preceding remnant flux states.

At approximately 180 ms after breaker closure, it can be seen (Figure 6) that the difference in C-phase flux levels started to reduce and then it changed sign. This must have been due to the neutral CT also running out of flux capacity and also due to the demagnetising effect of stored energy in the terminal CT secondary circuit reactance (mainly CT leakage reactance). This is a secondary circuit time constant effect that was ignored in the equation given earlier for CT core flux variation. A similar effect is can also be observed for the B-phase in Figure 6. Stored energy effects on CT secondary waveforms can also be seen in Figure 5.

Protection Response

The declared differential protection operating characteristic for the numerical relay that was applied is given in Figure 7. The protection is provided with a base current differential threshold setting and a low initial bias slope setting. A higher bias slope setting becomes effective for through current in excess of 1.8 per unit.

To assess how the relay performed during the event, Fourier filtering was applied to the recorded CT waveform samples to derive the fundamental frequency (50Hz) phase current vectors. The derived neutral CT currents are plotted for reference in Figure 8. The differential and bias (restraining) currents are plotted in Figure 9.

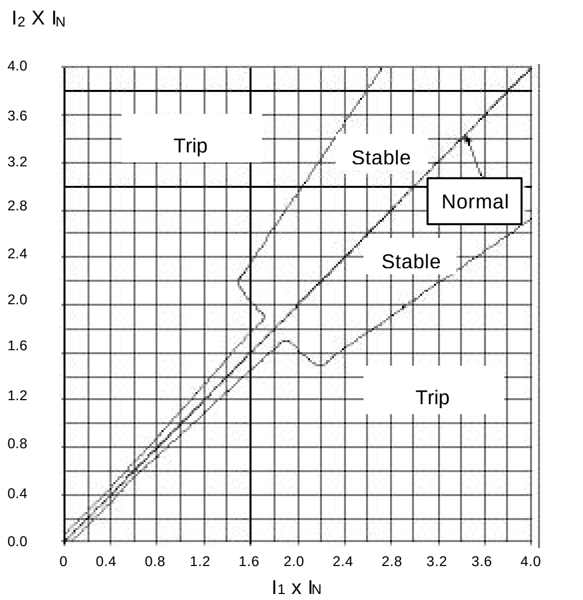

Figure 7 Declared Operating Characteristic of Applied Numerical Relay

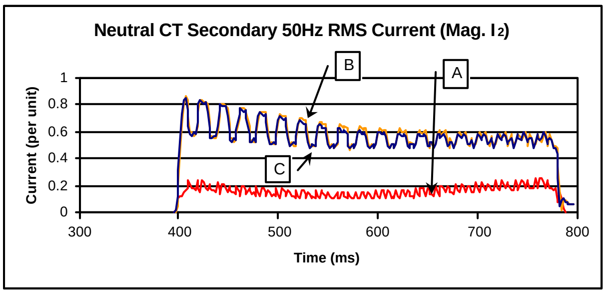

Figure 8 Neutral CT 50Hz RMS Magnitudes

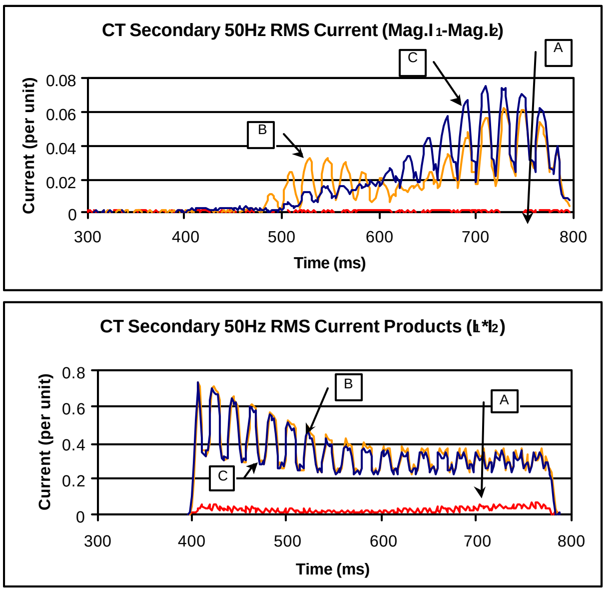

Figure 9 Derived 50Hz RMS Differential Magnitudes and Products

Figure 10 displays the applied B-phase and C-phase protection operating characteristics according to the manufacturer-defined relay operating criteria, but in a more familiar fashion and according to the settings applied in service. The variations in fundamental frequency differential and bias currents have also been superimposed in Figure 10.

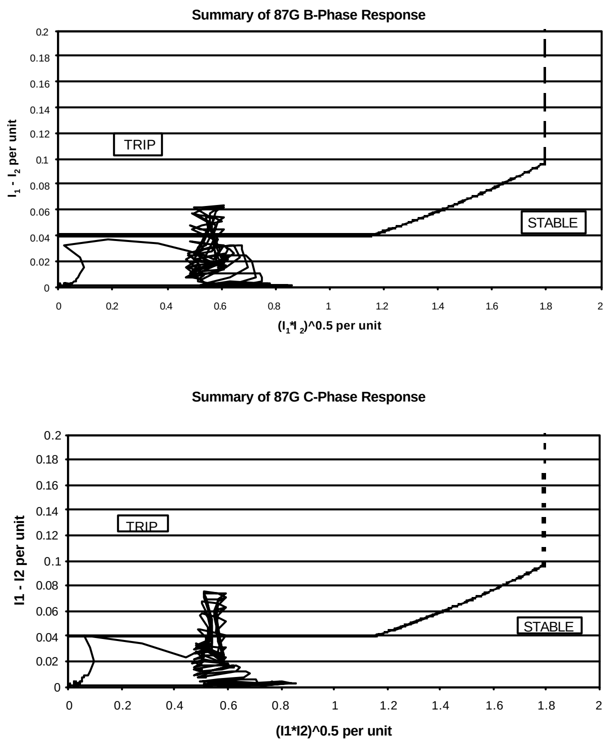

Figure 10 Derived B and C phase Differential Relay Responses – 1st Back-Energisation

It can be seen that both the C-phase and B-phase differential protection elements could have operated. With reference to Figure 9, it is noted that the C-phase differential protection element operating conditions were met first. This observation correlates with the actual recording of the C-phase protection trip time (see Figure 11).

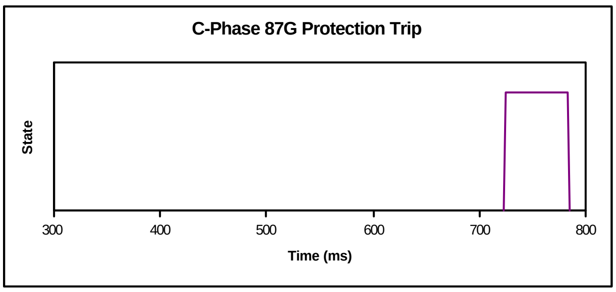

Figure 11 Actual Record of Protection Trip

SUMMARY OF PROBLEM AND A SOLUTION

Problem

The incorrect differential protection operation that has been considered was due to asymmetric CT saturation and a resulting differential spill current in excess of the protection operating threshold at a time when there was insufficient bias current to restrain the relay. It is concluded that the provision of protection bias alone cannot offer adequate stability for numerical generator differential protection for all possible plant operating conditions that result in a sustained stator current waveform offset.

The problem scenario arises when trying to suddenly energise a large transformer from a generator. This problem was acknowledged even before numerical relays came into service **[2]**. The problem is enhanced with modern numerical relay schemes since there has been a departure from true circulating current differential protection.

The settings that were applied by the user in the case that has been analysed are typical for generator differential protection application and they are in line with the manufacturer’ s application guidance. The CT’ s were also generously dimensioned for the application according to traditional practice for analogue relays. From Figure 10 it can be seen that significant and unacceptable setting changes would have been required to prevent the incorrect relay operation. Impractical CT designs would have been required to prevent saturation.

The author has studied the stated operating principles of other manufacturer’ s numerical generator differential protection and has concluded that some other relay designs would have fared no better in similar circumstances. The author has also studied another case of numerical generator differential protection maloperation when attempting to energise a large transformer from a generator (transformer rating ≥ generator rating). This was where an industrial power system distribution transformer was being energised from an emergency diesel generator. The contributing CT saturation effects at a low level of RMS through current were similar to those seen in this paper. The studies have also revealed that some manufacturer’ s CT sizing guidelines are either non-existent or apparently inadequate.

Possible Solution

One possible solution to the problem that is suggested by the author, but which has not yet been put to the test, is summarised in Figure 12. Even where a numerical protection scheme is applied, a circulating current protection scheme with moderate differential circuit stabilising impedance can still be created as shown. Stabilising resistors may not be fashionable, but they offer a simple and well understood means of reducing differential spill current and increasing bias current in the event of CT saturation for through faults and other current disturbances for external events.

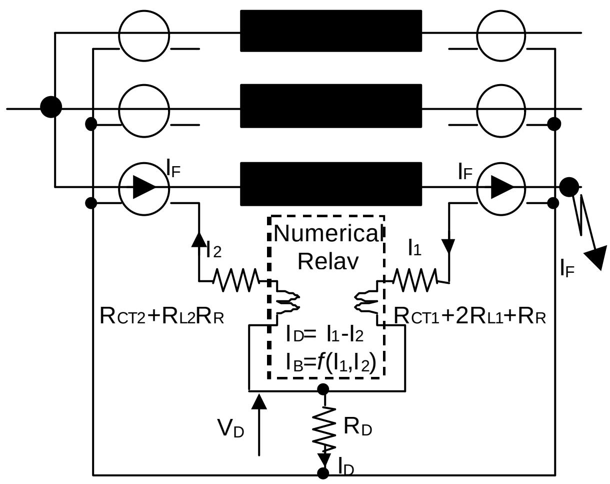

Figure 12 Numerical Circulating Current Differential Protection – Revised Application

CONCLUSIONS

The introduction of numerical generator differential protection schemes has led to a departure from traditional circulating current differential protection, such that stability for through faults and disturbances is entirely dependent on bias or other techniques.

When suddenly energising a large transformer from a generator, the application of differential protection bias alone may not guarantee protection stability in the face of sustained offset current waveforms. A large transformer is one with a rating similar to or larger than that of the generator. The need for such switching operations can arise during black start sequences for some plant or when operating plant from emergency generators. The maloperation of differential protection due to latent design limitations during critical operations could have serious consequences.

To overcome the numerical protection stability problems highlighted in this paper, it is suggested that a simple solution would be to return to the application of true circulating current protection and to apply some moderate differential circuit stabilising resistance in addition to bias.

REFERENCES

1. A R van C Warrington, “ Protective Relays – Their Theory and Practice” , Section 9.4.4, Volume 2, 3rd Edition, 1977, ISBN 0 412 15380 7

2. “ Applied Protective Relaying” , Paragraph 2, Page 6-3, 1982 Edition, Westinghouse Electric Corporation