EHV SHUNT REACTOR PROTECTION
-APPLICATION AND EXPERIENCE-

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INTRODUCTION

Although some references (1 through 4) do exist, shunt reactor protection is not very thoroughly dealt with in the relay literature. In particular, not much guidance is available for detection of interturn faults in one phase, as these are difficult to analyze quantitatively. The problems of false operation of electrical relays due to their response to external system disturbances are not mentioned at all because very little is known of the causes.

Consequently, B.C. Hydro engineers (and others) had to depend very much on their own resources to develop suitable protection schemes for EHV reactors, and discover from years of hard experience with misoperations, the mistakes made and the improvements necessary to render these schemes secure and apply them with confidence.

With the large majority of B.C. Hydro's EHV shunt reactors being line connected, operation of the reactor protection trips the associated line and blocks high-speed auto-reclosing, thus degrading system reliability. Therefore, a great deal of effort was put into determining the underlying causes of false operations, through analysis of outage reports, staged switching and fault tests in the field, and computer modelling of system and equipment parameters and simulation of system events such as faults, line tripping, line restorations, and similar.

As a result of these efforts, it was possible to determine the system responses and the mechanisms of the the undesired reactor protection operations. Detailed knowledge of the phenomena allowed changes to existing protection, and selection of devices for future installations, to be made with confidence. These changes have greatly reduced the number of such undesired protection operations, leading to a substantial improvement in system reliability, security and performance.

PROTECTION APPLICATION PRINCIPLES

In selecting protective devices and schemes for the EHV shunt reactors, the objective was to provide detection for all possible faults in a single phase unit of a 3-phase bank, by at least one primary and on backup device. Faults

considered were interturn winding faults, winding to ground faults, and core failures.

To this purpose, a number of electrical relays and non-electrical protective devices were applied. An overall protection schematic is shown in Fig. 1.

Non-Electrical Protection

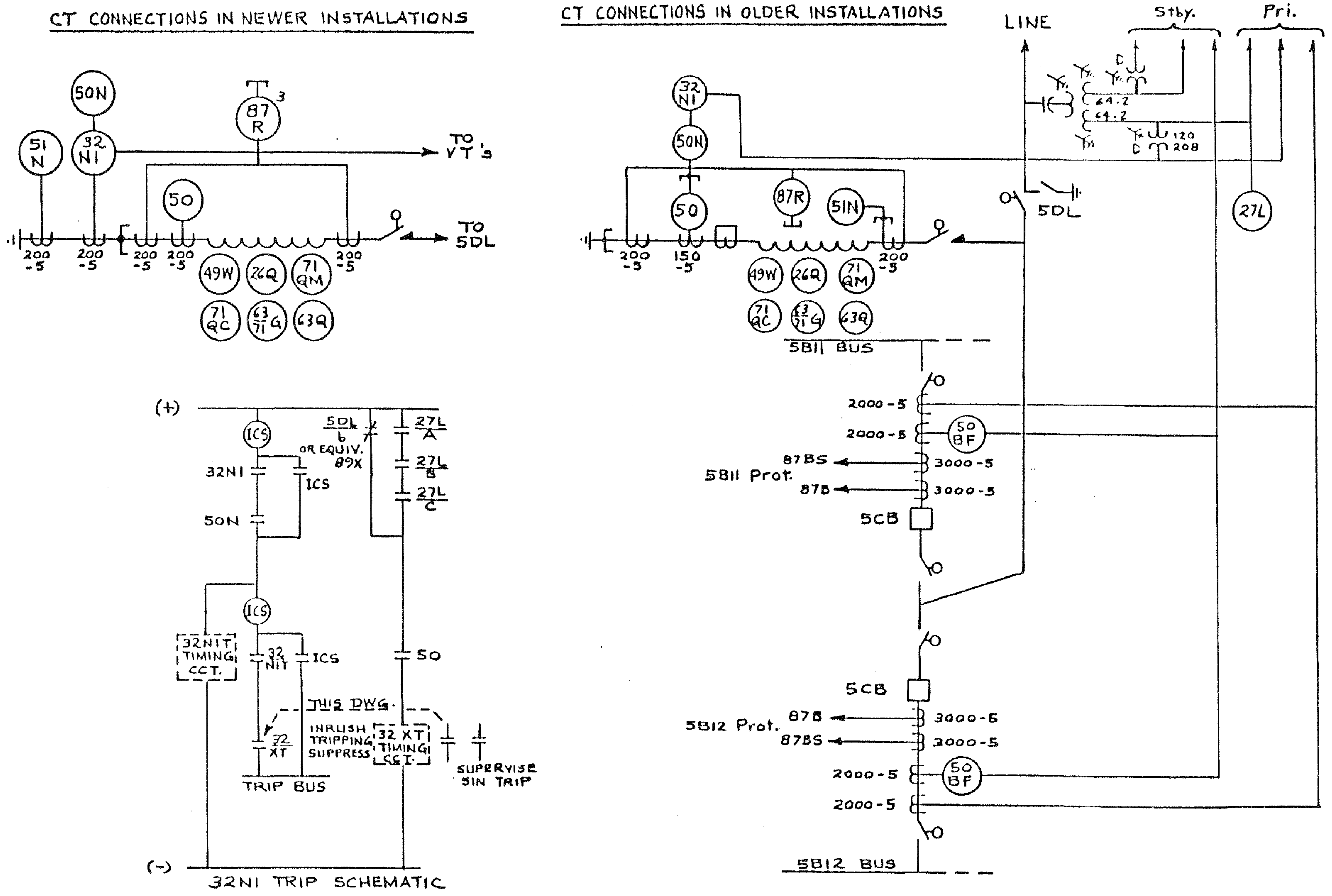
The application of non-electrical protective devices has been extensively dealt with in previous paper (Ref. 4). However, for completeness of the subject material of this paper, a summary description is included here.

Until the early seventies, the only non-electrical device connected to trip was the sudden pressure element of the gas detector relay. Traditionally, this device is considered a sensitive and fast acting protection for winding faults. The gas accumulation element, and the various oil and winding thermal detectors, were connected for alarm only. Since then, several core failures on EHV and lower voltage reactors have been experienced, which usually started with localized burning of the core, increasing in area, and leading eventually to considerable damage to core legs and yoke. These experiences prompted a re-evaluation of the non-electrical protection, and eventually arriving at the present practice of alarming for "less severe", and tripping for what is deemed indication of "more severe" faults.

Experience with Core Failures

Two core failures experienced on lower voltage reactors can be considered "benchmarks" for reviewing and revising our early practices. One was a case of iron core burning in a 75 Mvar, 12 kV reactor in a remote location. The gas detector relay did not operate, and the only fault detection was by the temperature detectors which at that time were connected for alarm only. When the service crew finally arrived after several hours and manually tripped the reactor, the core was virtually destroyed. We subsequently standardized on trip output from the temperature detectors.

The other noteworthy case was a core fault in a 125 Mvar, 230 kV reactor, where the sudden pressure element of the gas detector relay failed to operate, but the pressure relief device operated. This is essentially a spring-loaded valve which opens under the high internal pressure protecting the tank against possible rupture. The model used by B.C. Hydro is equipped with an electrical contact, which until then had not been used. It was subsequently connected for tripping as a standard feature. Lack of gas detector relay operation was attributed to the possibility that the build up of static pressure proceeded slowly rather than suddenly, to the point where the relay would no longer be operational.


CT CONNECTIONS IN NEWER INSTALLATIONS

CT CONNECTIONS IN OLDER INSTALLATIONS

32NI TRIP SCHEMATIC

FIG. 1 LINE-CONNECTED 500kV REACTOR PROTECTION SCHEMATIC

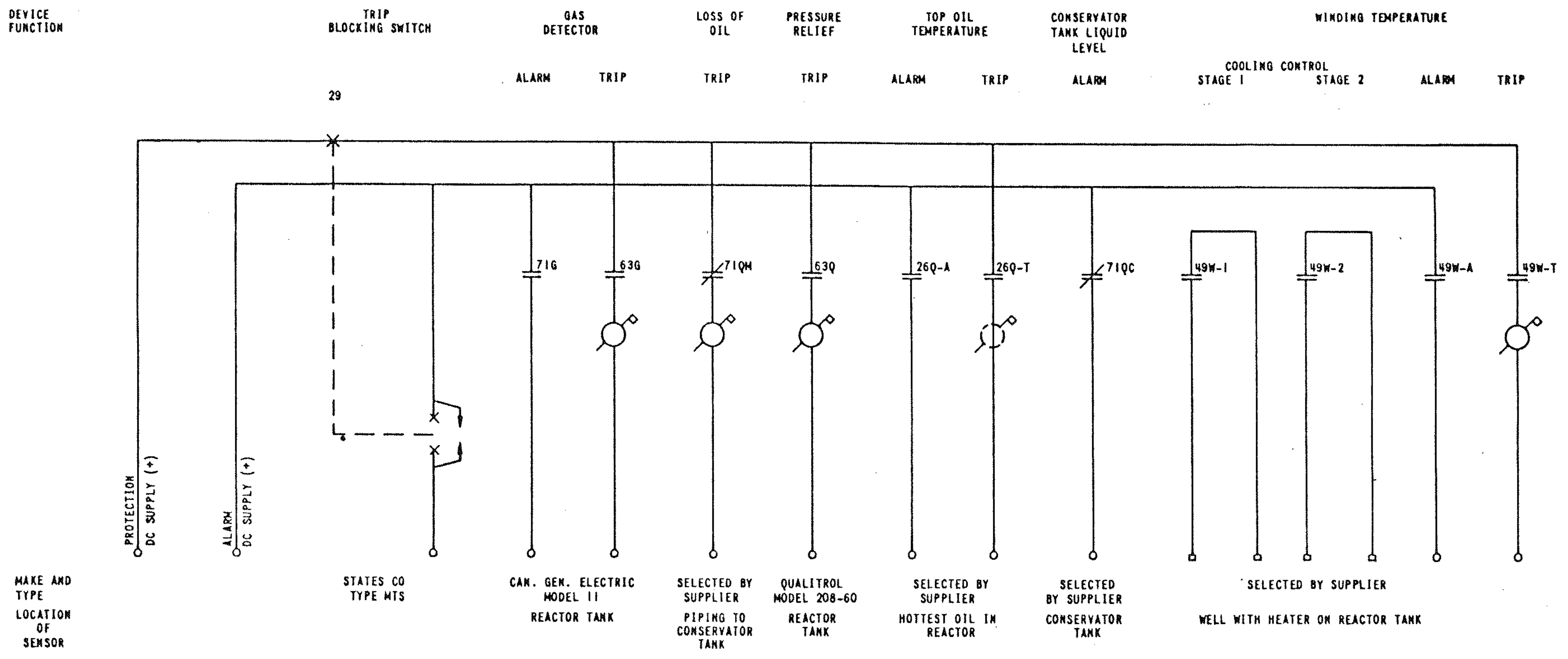


FIG. 2 NON-ELECTRICAL PROTECTION

Present Usage of Non-Electrical Devices

Based on experience gathered through the years, the following usage of non-electrical devices for alarm and tripping has evolved, for EHV and lower voltage reactors except dry type (refer to simplified dc schematic, Fig. 2).

Alarm only

Gas accumulation element of gas detector relay, device 71G.
Low conservator tank liquid level, device 71QC.
Top oil temperature 80°C, device 26Q-A.
Winding hot spot temperature 105°C, device 49W-A.

Tripping

Sudden pressure element of gas detector relay, device 63G.
Loss of oil indicator, device 71QM.
Pressure relief valve, device 63Q.
Winding hot spot temperature 115°C, device 49W-T.
Top oil temperature 95°C, device 26Q-T.

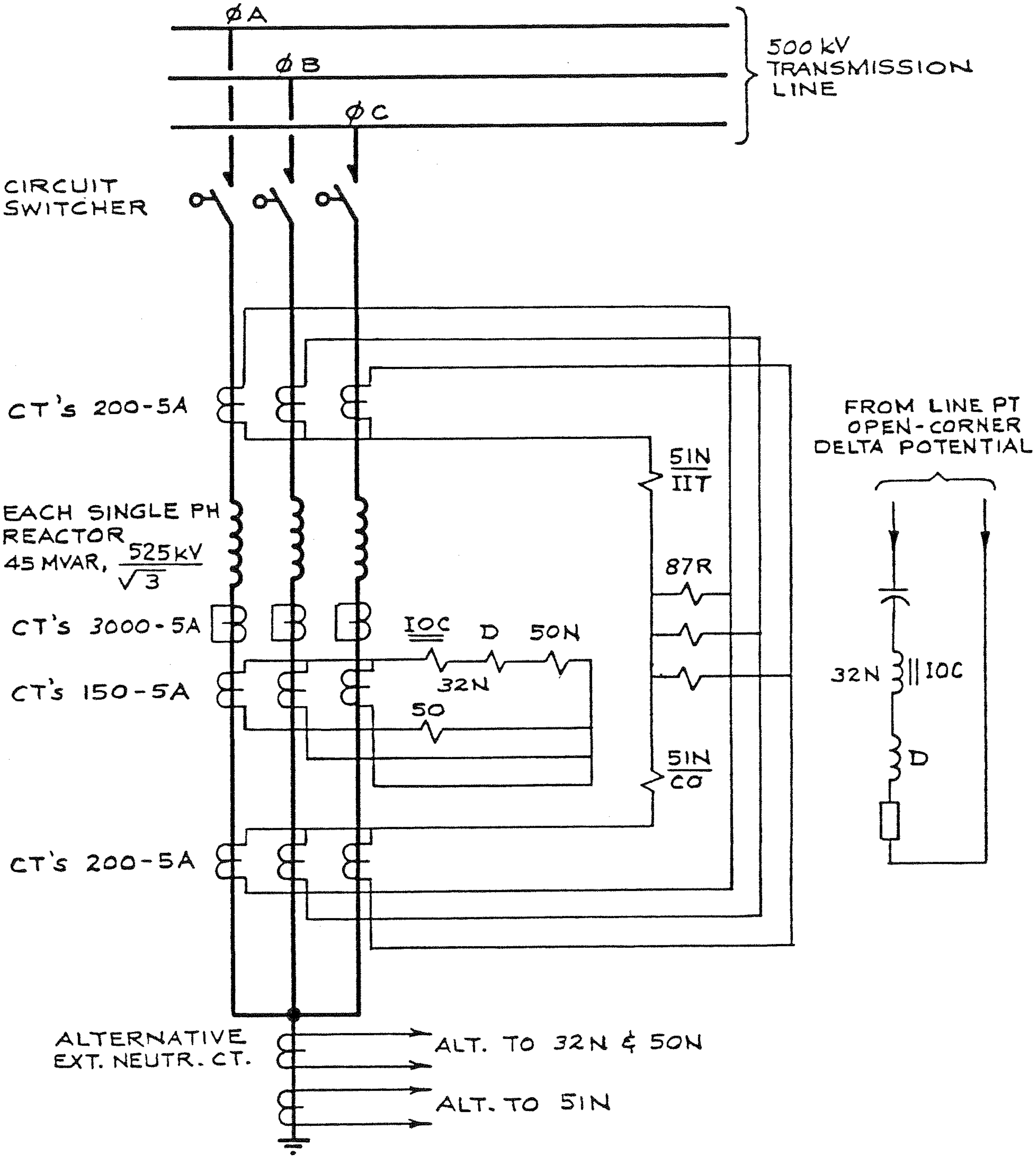
Electrical Protection

Function of the electrical protection is the detection of winding faults, such as interturn faults in one phase, or winding to ground (e.g. to core or to tank) faults. (Short circuits between phases are not possible in banks made up of single phase EHV reactors.) A 3-line schematic of the devices applied is shown in Fig. 3.

Interturn Fault Detection

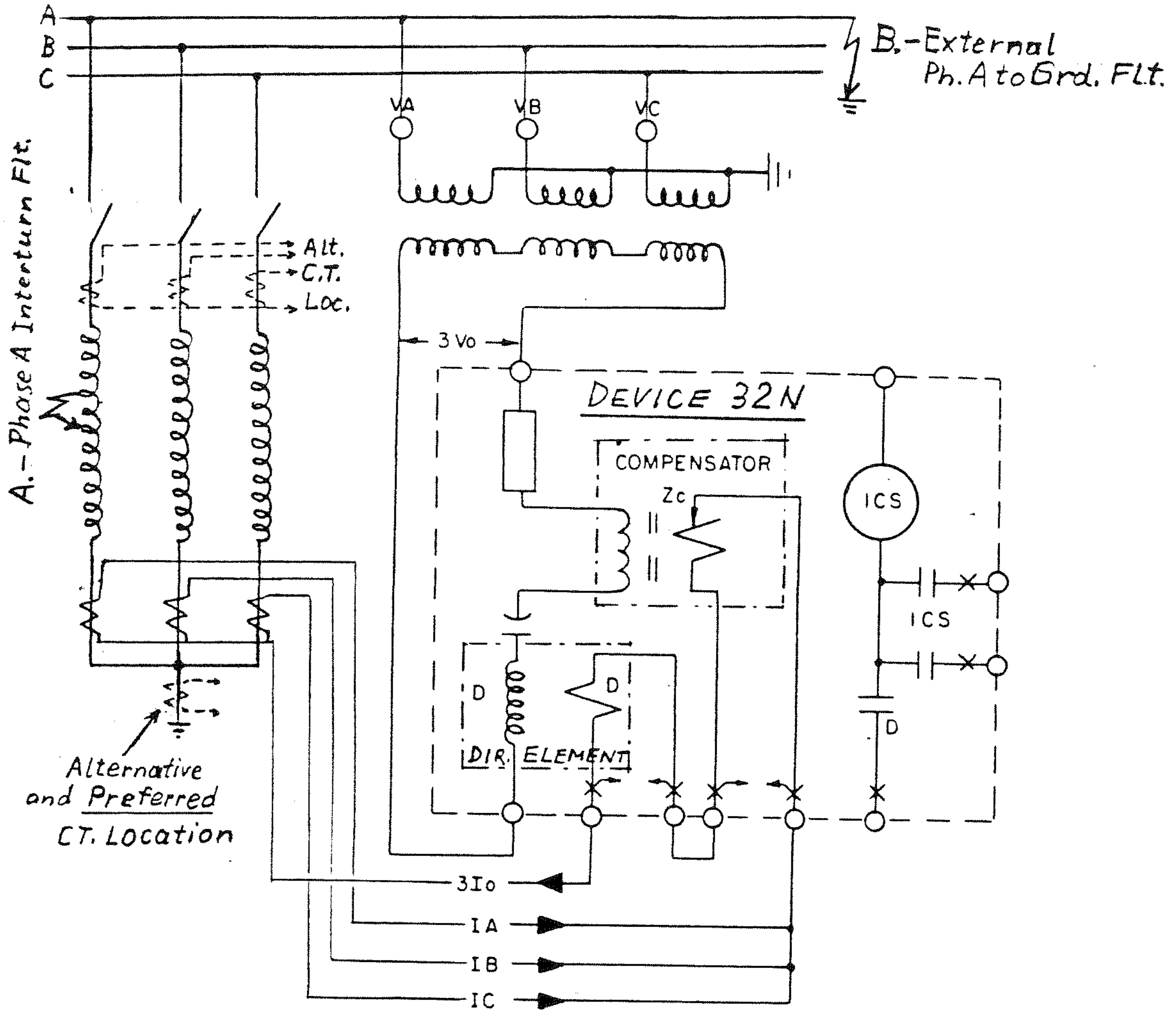
Short circuits between one or several turns in the same phase will reduce the impedance of that phase and result in increase of current in the same. In reactors supplied from a grounded system, with their neutral connected to ground, either solidly or through a neutral tuning reactor (the latter not shown in Fig. 1), a neutral current (i.e. zero sequence) flow will result. No difference current will flow through differential relays, thus the latter would not detect interturn faults.

Based on the criterion of reduced impedance of the faulted phase, an often used protection is phase to ground connected impedance relays. Such devices can be effectively applied if the reactor has a linear characteristic even at higher than normal voltages. Some recently installed EHV reactors in B.C. Hydro's system have been provided with this mode of protection, but no operating experience can be reported yet.

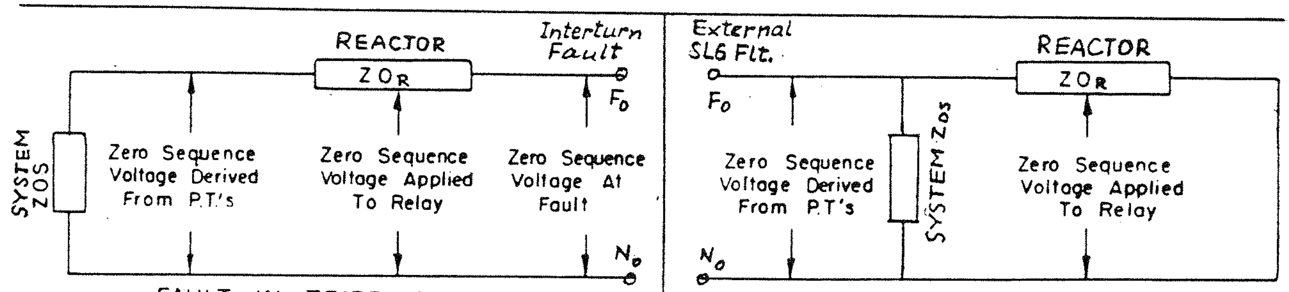


500 kV SHUNT REACTOR TYPICAL RELAY SCHEMATIC

FIG. 3



BASIC RELAY CIRCUIT



FAULT IN TRIPPING DIRECTION

FAULT IN BLOCKING DIRECTION

FIG. A

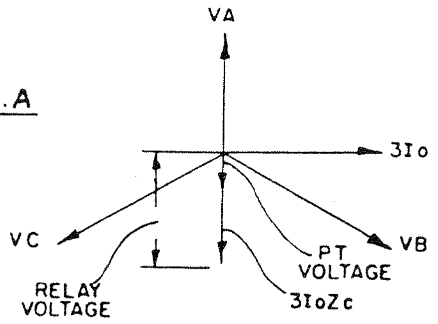
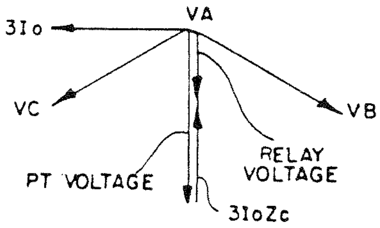


FIG. B



DIAGRAMS SHOWN ABOVE ARE ON THE BASIS OF PHASE "A" FAULT.
COMPENSATED ZERO SEQUENCE DIRECTIONAL RELAY.

FIGURE 4

For all previous installations, B.C. Hydro has elected to use directional neutral current relays (device 32N). Its operating principle is shown in Fig. 4: It is directionally oriented such it will see zero sequence currents into the reactor for interturn faults, but not out of the reactor for external line to ground faults. As this relay is extremely sensitive, it is supervised by a level detector 50N, set at neutral current of approximately 5 to 10 percent of reactor rating. Tripping is slightly delayed by a tripping timer 32NT, and upon energization of the reactor further delayed by an inrush tripping suppressor 32XT whose purpose will be explained later. The relays were connected to the residual secondary lead of phase CT.s in the earlier installations, to separate neutral CT.s in more recent installations. The effects with regard to false operations are significantly different for the two alternatives.

Backup electrical protection for interturn faults is provided by an inverse time neutral overcurrent relay 51N with instantaneous trip element (the latter recently disabled based on the diagnosis of a number of false operations as discussed later).

Winding to Ground Fault Detection

Differential schemes have been applied as primary line for the detection of winding-to-core or winding-to-tank faults. In the majority of installations, low impedance differential relays with sensitive time element and higher set instantaneous trip have been selected, recently, a switch to high impedance type relays was made in view of the high incidence of false operations of the former.

Backup electrical protection for winding to ground faults is provided by the earlier described neutral time overcurrent relay 51N.

OPERATING EXPERIENCE

The only reactor faults experienced over a period of some fifteen years were a number of core failures, all of which were detected by the various non-electrical devices described earlier, and by these devices only.

No reactor faults were ever experienced in which the electrical relays were called upon to operate. On the other hand, such relays were the cause for a substantial number of erroneous tripouts. These can be divided into two categories - those being the direct or indirect results of reactor switching, and those occurring during or after system disturbances or line or equipment switching external to the reactors.

Diagnosis of the first category was relatively easy, it was essentially completed and remedial measures implemented in the latter part of the seventies. Diagnosis of the second categroy was substantially more difficult, and a major breakthrough was not achieved until 1982. A third category, false tripping by non-electrical devices because of inadequate surge suppression of control cables, was also successfully diagnosed recently and remedial measures implemented. These three categories are discussed in the following sections.

False Operations Resulting From Reactor Switching

False operations were experienced during reactor switching (or line energization with line-connected reactor) by the differential protection (87R) and by the interturn directional relay (32N).

Differential Protection

The traditional transformer differential inrush problem, namely high side current not accompanied by low side current, does not apply to reactor differential protection: what goes into the bus-end CT.s must also go through to the neutral-end CT.s. However, experience has shown that reactor inrush currents can have significant dc offset with long time constants, resulting in unequal transient CT saturation and thereby differential error current leading to incorrect tripouts. A number of false operations were experienced until the relay time elements were sufficiently slowed down and the instantaneous elements de-sensitized. (In the very first installations, instantaneous relays only had been provided, which were later replaced by timed relays with higher-set instantaneous elements). Fig. 5 shows switching inrush currents into a 500 kV reactor bank - note the saturation of the A-phase current transformer. Fig. 6 shows a similar oscillogram for a low-voltage reactor, this figure is particularly demonstrative because it also shows the differential error current due to unequal CT saturation at the two ends of a reactor phase. For differential error currents of the magnitudes displayed in Fig. 6, even differential relays with traditional percentage-slope characteristic could not be expected to remain immune from erroneous operation.

Interturn Fault Protection

A number of recurring, but inconsistent, erroneous tripouts by the interturn fault relay 32N were experienced at various locations. Increasing the delay of the tripping timer form 0.1 to 0.2 to 0.25 to 0.4 seconds did not eliminate the problem. Eventually, through a number of timing tests at various locations, it was determined that the neutral component of the inrush current may last in the order of seconds. It was also determined that relays connected to a neutral CT would generally reset quicker than those connected to the residual lead of phase CT.s. As a remedy, an additional timer 32XT was added as inrush tripping suppressor, which will hold tripping disabled as long as the reactor is de-energized, and for some time following energization. It was further decided to avoid the residual relay connection in new installations (but not to delete it in existing ones). As the sensitivity of the directional relay was found to be uncontrollable, an adjustable current level detector 50N was added. Fig. 7

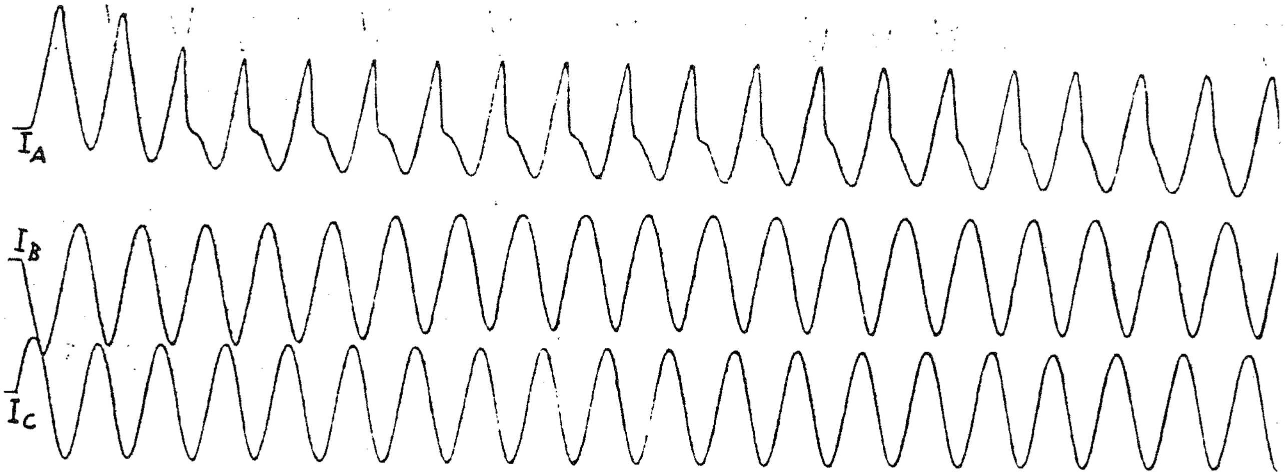


FIG. 5 – ENERGIZING 3 1-PH 525/$\sqrt{3}$ kV 45 MVAR REACTORS

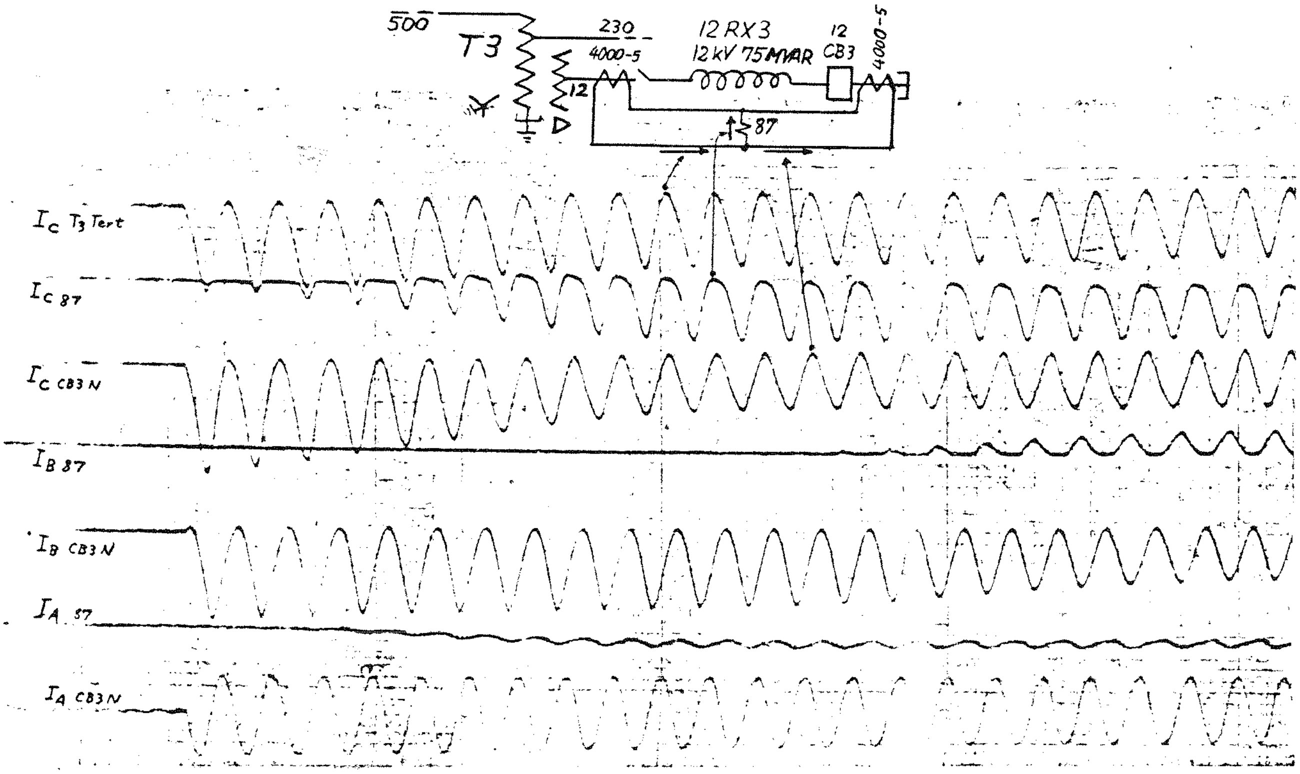


FIG. 6 – ENERGIZING A 12.6 kV 75 MVAR 3-PH REACTOR

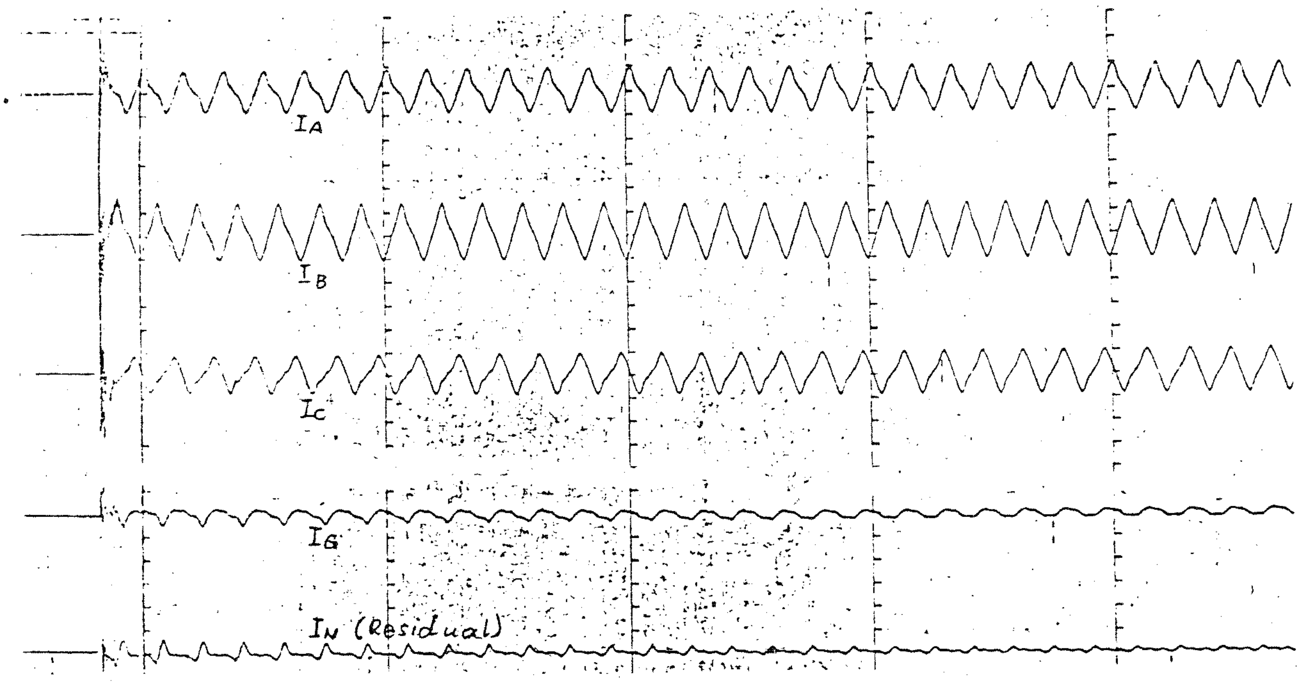


FIG. 7 - ENERGIZING A 230 kV 40 MVA 3-PH REACTOR

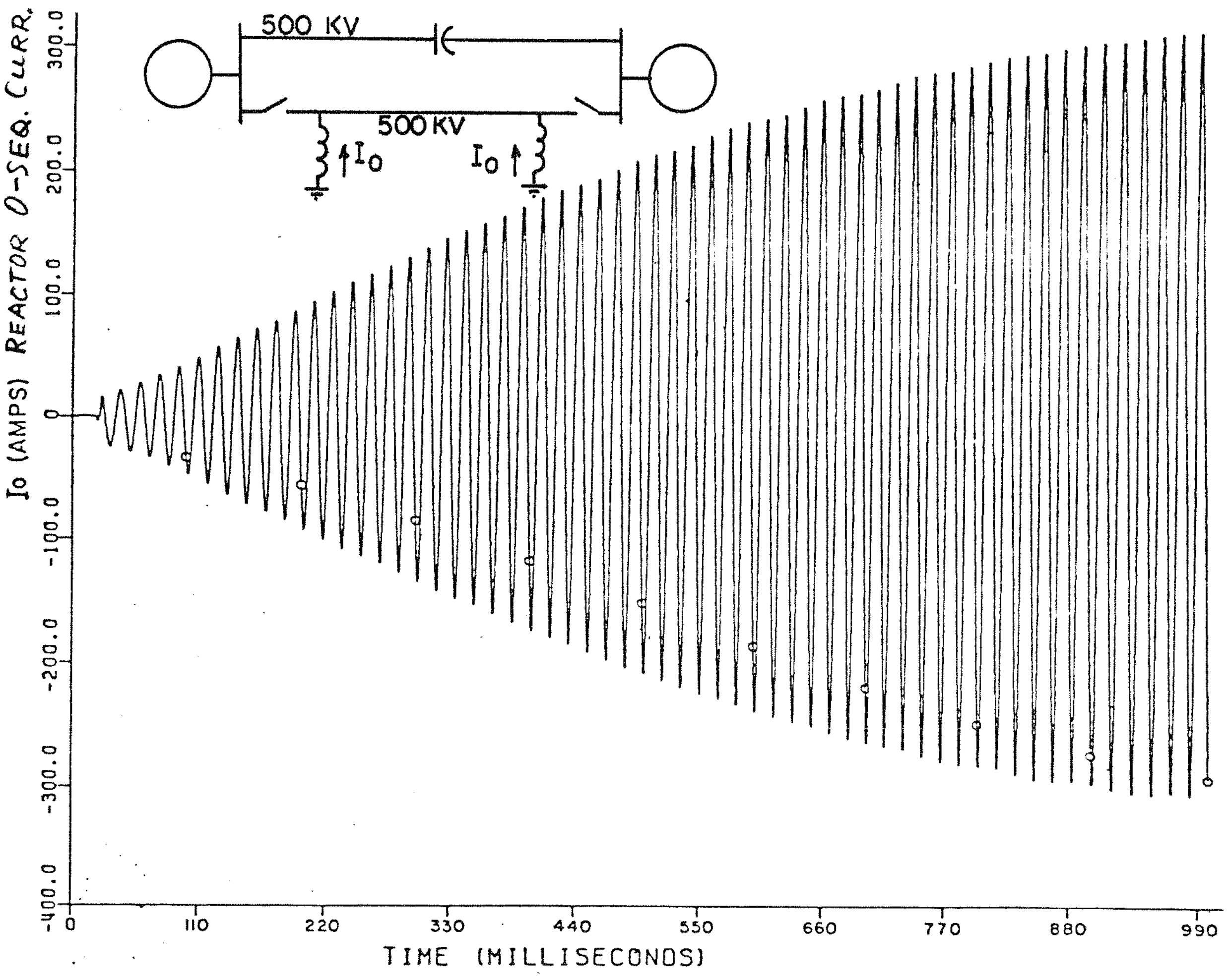


FIG. 8 - RESONANT COUPLING TO PARALLEL LINE

shows neutral components of inrush currents into a line connector reactor (in this case 230 kV class). Note the difference in wave shape between neutral and residual current, due to CT saturation.

False Operations During External System Disturbances

False protection operations continued to occur during system events having nothing to do with reactor energization, such as line faults, line openings without faults, line current restoration, transformer switching. These were, with the aid of staged field tests and of computer simulations, eventually diagnosed. They are discussed in the following.

Resonant Coupling to Parallel Line

Tripout by the backup interturn fault relay 51N was experienced on repeated occasions after the line associated with the end-connected reactors had successfully cleared a fault and was isolated at both ends, with the parallel line using the same right-of-way in service. Continuous reactor neutral current operated and locked up relay 51N, so that the isolated line could be neither automatically reclosed nor reclosed by supervisory control. An oscillograph recording obtained from one of these events showed gradually increasing voltages on the supposedly dead line. A computer simulation eventually indicated that these were zero-sequence voltages from resonant capacitive coupling to the parallel line. Fig. 8 shows a graphic printout of a reactor zero sequence current produced by the computer simulation.

As remedy, trip output of relay 51N was modified to be disabled when the line is de-energized, by the earlier mentioned inrush tripping suppressor. Note that the line voltage relays 27L which supervise the tripping suppressor must be phase-to-phase connected, so as not to respond erroneously to the zero-sequence phase-to-neutral voltages resulting from the coupling.

EMTP Study to Diagnose Various Other Causes

Even after the investigations described so far and the corrective measures arising from these were completed, incorrect tripouts of shunt reactors continued to occur with intolerable frequency, and in connection with what appeared to be unrelated events in the system. Table I lists for twenty-four (24) EHV reactor banks in the system, eighty-one (81) incorrect tripouts during the period of January 1977 to September 1982, thirty-seven (37) of these by electrical protection, mainly by the well known offenders - interturn fault relay 32N and differential relay 87R. One of these misoperations even occurred on a completely unsuspect reactor during a staged fault test under controlled conditions on an unrelated line, resulting in eventual system breakup.

As no meaningful data could be extracted from system oscillograms on these various events, part of the 500 kV system most hit by these misoperations was

TABLE I

Performance Record of 500 kV Shunt Reactor Protection Between 1 January 1977 and 30 September 1982

Station	No. Of Reactors In Station	Incorrect Tripouts over Survey Period From Misoperations Of Electrical Relays	From Other Causes*1	Total
ASHTON CREEK	1	2	-	2
CRANBROOK	1	-	-	-
GLENNANNAN	1	-	-	-
G.M. SHRUM	2	6	4	10
KELLY LAKE	4	6	2	8
MICA	2	1	11	12
NICOLA	4	7	21	28
PEACE CANYON	1	-	4	4
SELKIRK	1	2	-	2
TELKWA	1	-	-	-
WILLISTON	6	13	2	15
System Total	24	37	44	81

Note: *1 Such as surges, grounds, e.m.i. in control cables connecting to non-electrical protective devices, or misoperations of such devices themselves, or human error during wiring or testing, etc.

during 1982 modelled in a computer transient study using the BPA/UBC Electromagnetic Transients Program (Ref. 5). A series of fault and switching conditions were simulated on selected points of the system model shown in Fig. 9, which included simulation of specific historic system events. Shunt reactors and series capacitors were modelled as shown in Fig. 10. Current transformers were not modelled, therefore conclusions as to expected CT secondary current outputs were based on previously acquired knowledge of CT transient performance. Transformers with their magnetization and hysteresis characteristics were also not modelled, thus staged transformer switching field tests (described in the next section) provided the insight into reactor protection misoperations associated with transformer switching.

The following are highlights of the findings of the EMTP study (Ref. 6):

1. Misoperations of Instantaneous Element of Backup Interturn Fault Relay 51N. Reactor primary neutral currents following line faults on series - compensated lines may have high-magnitude low-frequency components which cause operation of this element. Fig. 11 shows a computer plot of this simulation, Fig. 12 shows an oscillogram of an actual system event. The fault is on the far side of the series capacitor, with respect to the reactor under study.

2. Misoperations of Instantaneous Elements of Low Impedance Differential Protection 87R. Historically, this relay operated during or after line faults, always the relay on the reactor phase connected to the faulted line phase. The EMTP confirmed this through the display of primary reactor phase currents having dc and/or low frequency ac components during or after a line fault, resulting in unequal transient saturation of phase end and neutral end CTs. (Note: Even though CTs may be <u>specified</u> the same, they rarely have exactly the same saturation characteristics).

   Fig. 13 shows pure DC reactor phase current (L/R discharge) for a bolted line fault near the reactor. Note the decay time constant of the DC is the L/R ratio of the shunt reactor, about 1 second. This phenomenon is independent of any line series compensation.

   Fig. 14 shows reactor phase current for a bolted ground fault near the far end of a series compensated line, and Fig. 15 for a ground fault with substantial tower footing existance just beyond the series capacitor location. In both cases, the line current through the series capacitor is too low to effect protective gap flashover, and the capacitor is bypassed on current zero after line tripping. Thus, the reactor A-phase current contains first a low frequency component, then a decaying DC component.

3. Misoperations of Directional Zero-Sequence Interturn Fault Relay 32N. This relay is prevented from any operation by the inrush tripping suppressor at events where the line associated with the reactor is de-energized.

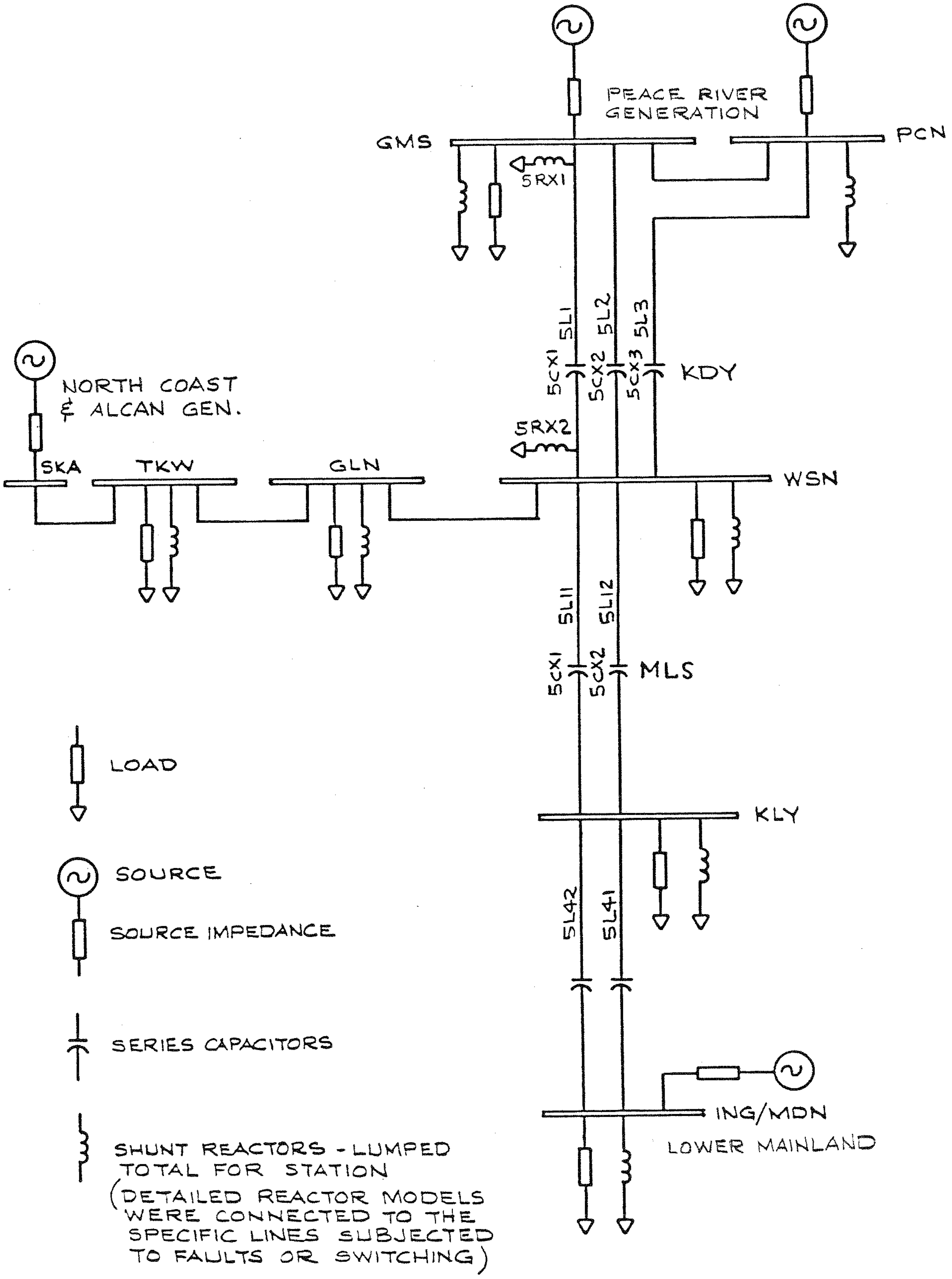


Fig. 9 - SYSTEM 1-LINE DIAGRAM FOR COMPUTER SIMULATION

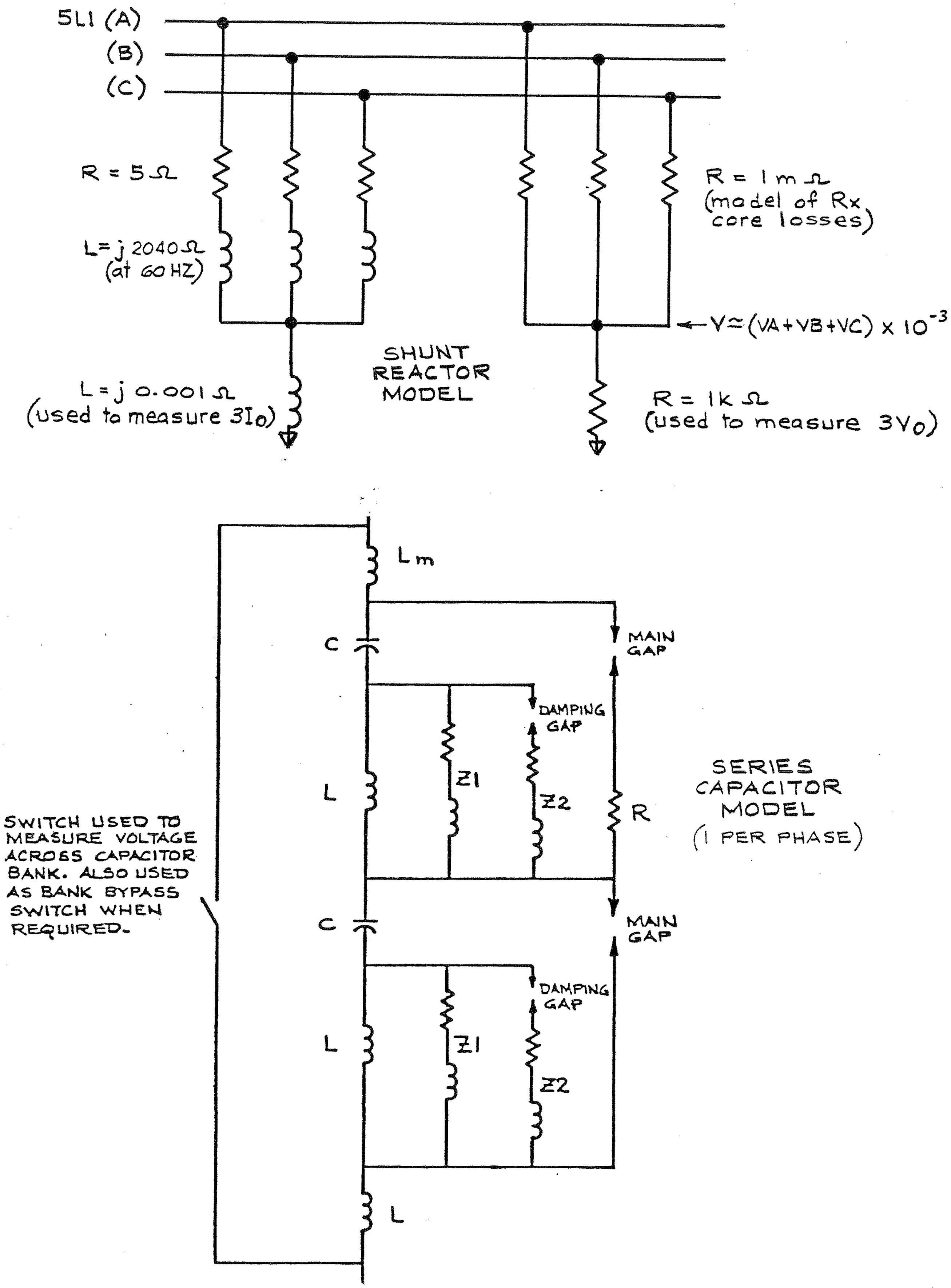
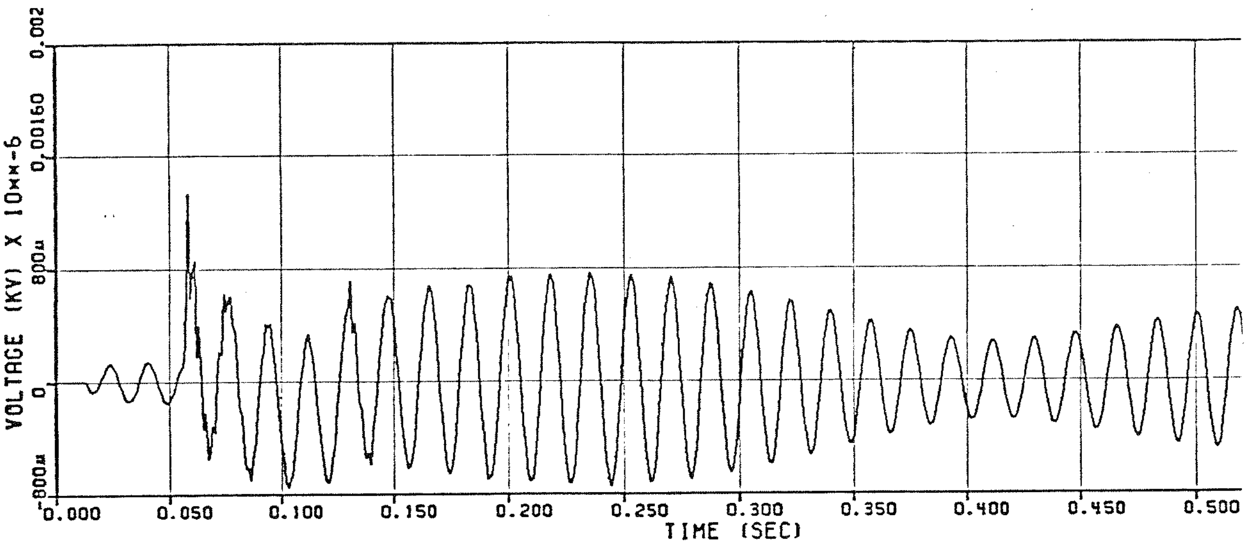
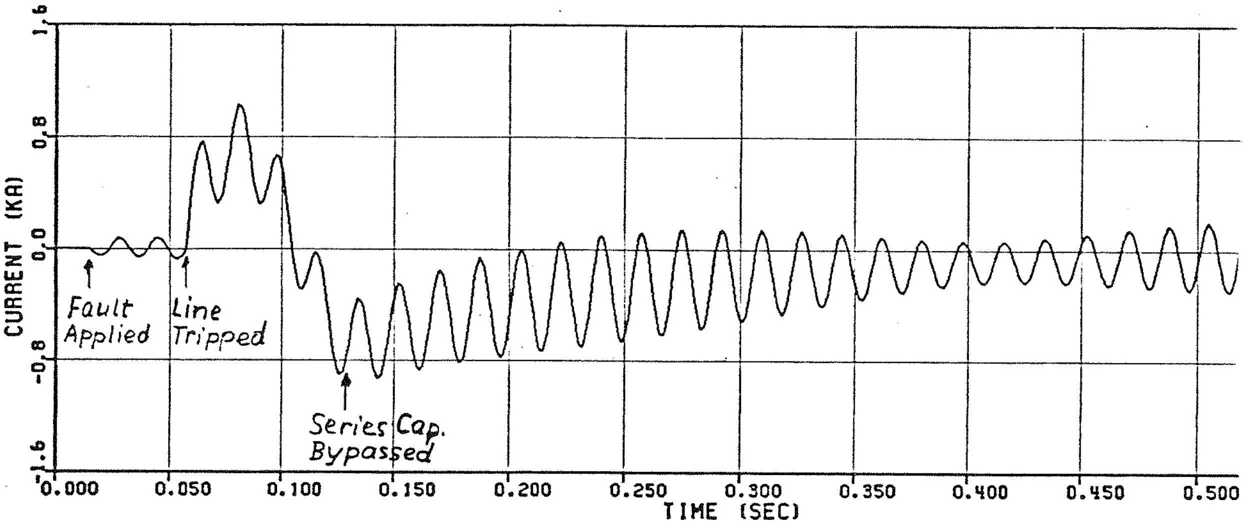


Fig. 10 – SHUNT REACTOR AND SERIES CAPACITOR MODELS



GMS REACTOR VOLTAGE - 3×VO



GMS REACTOR CURRENT - 3×IO

FIG. 11 - A-G FAULT (22 OHMS) NEAR KDY AT VO, LINE CLEARED

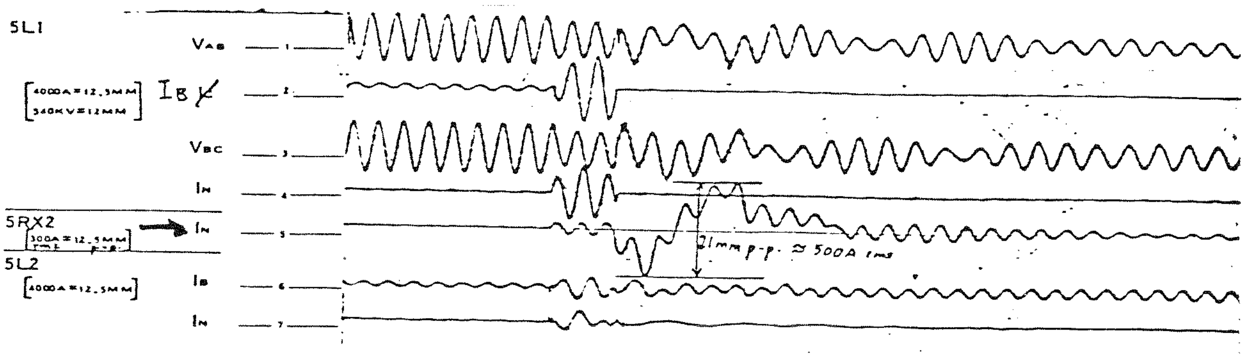
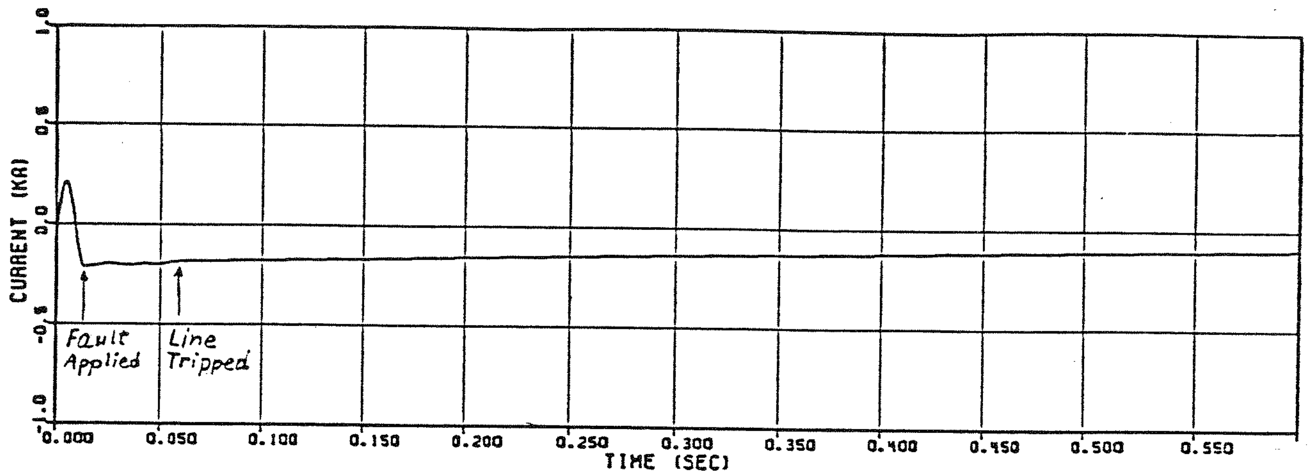
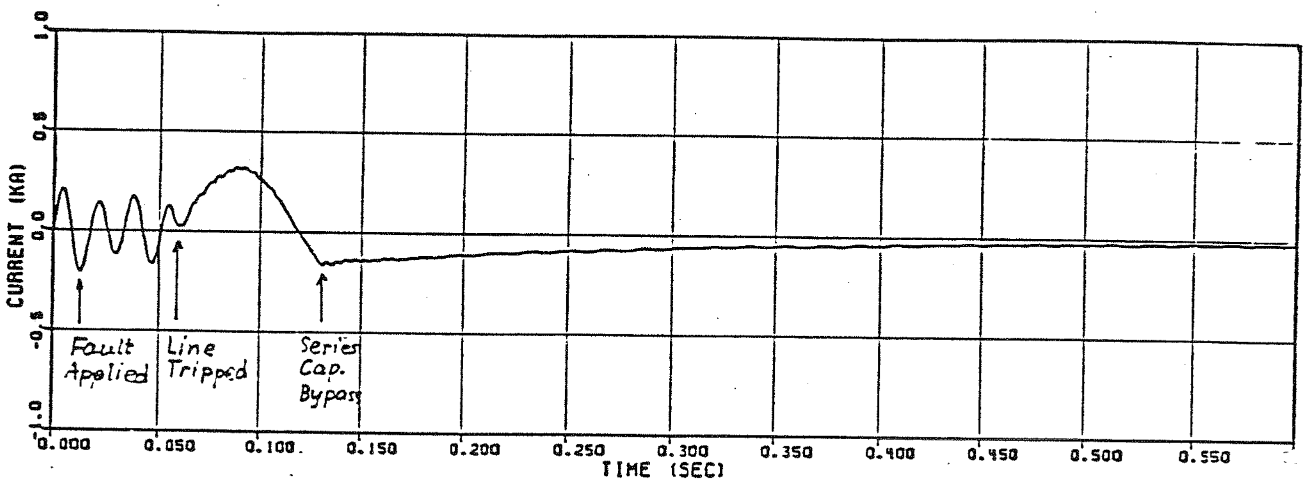


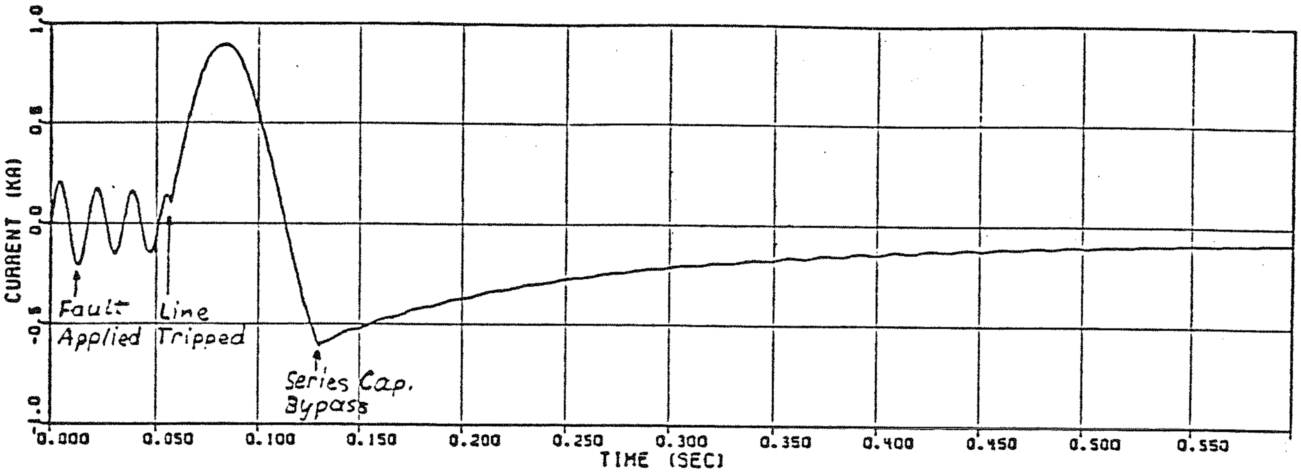
FIG. 12 - 5L1 B-G FAULT 25 AUGUST 1981



WSN REACTOR CURRENT - PHASE A
FIG. 13 - A-G FAULT NEAR WSN AT VO, LINE CLEARED, CAP. BYPASS



GMS REACTOR CURRENT - PHASE A
FIG. 14 - A-G FAULT NEAR WSN AT VO, LINE CLEARED, CAP. BYPASS



GMS REACTOR CURRENT - PHASE A
FIG. 15 - A-G FAULT (22 OHMS) NEAR KDY AT VO, LINE CLEARED, CAP. BYPASS

However, if the relay rceives operating quantities during events where the line voltage does not disappear, the inrush tripping suppressor is not activated and this safequard is not in effect. Operating quantities may be caused by true primary low-frequency neutral currents, or by residual error current (in the case of residually connected relays) due to unequal phase CT saturation when these are subjected to dc and/or low frequency ac transients following faults, line opening, or line reclosing.

Fig. 16 represents simulation of a series-compensated 500 kV line, transmitting about 900 A, having been opened at one end, leading to tripout of the open-end line-connected shunt reactor by relay 32N. The high-magnitude low frequency reactor neutral current displayed, resulting from the series capacitor's stored energy discharge, is the cause of this relay operation.

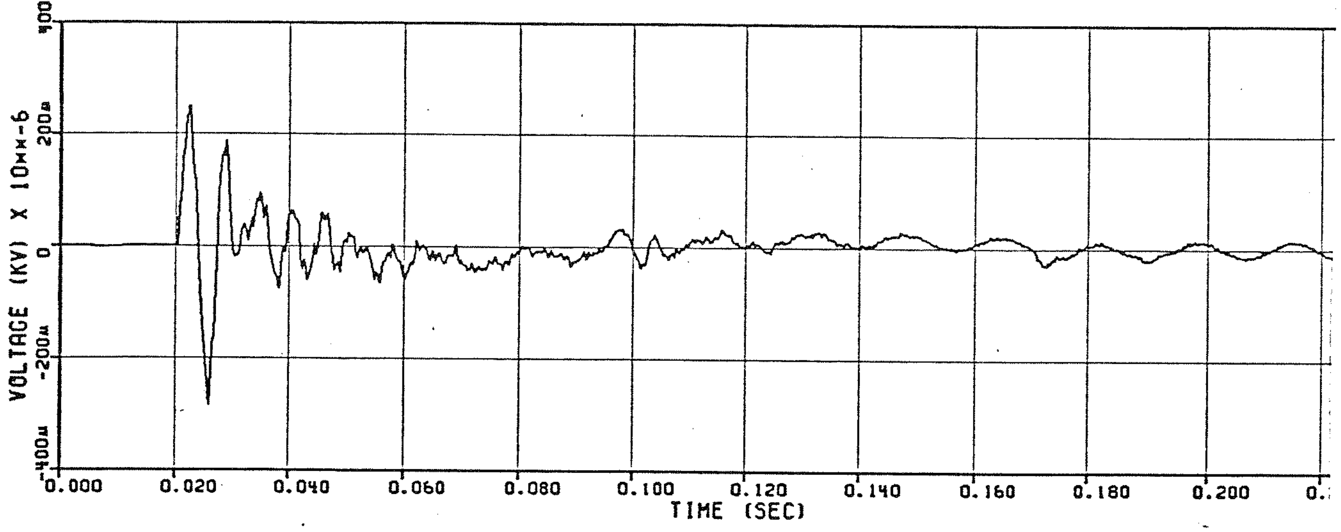
Fig. 17 represents a follow-up simulation of an actually staged phase A-B fault test in a 500 kV line near a substation bus, which was cleared, auto-reclosed after 0.6 seconds, and cleared again. Shortly after the second fault clearing, an unrelated reactor connected to a different line position was tripped by relay 32N which was residually connected. The simulation displays large dc components with slow decay in the reactor's A and B phases, after the first incident fault and again after the reclosed-upon fault. The conclusion is that the accumulation of dc flux caused unequal saturation of the phase CT.s and an erroneous secondary residual current which operated the relay.

Fig. 18 is a simulation where a 500 kV line, with line connected shunt reactors at both ends, was successfully energized from one end. When several minutes later the remaining open end was closed to establish current throughput, the reactor connected to that end was tripped by relay 32N (residually connected). The phase current plots show that, at the moment the second end of the line was closed, the reactor phase currents shifted from pure ac to currents with considerable dc components with very slow decay. Again the conclusion is that unequal saturation of the phase CT.s resulted in erroneous secondary residual current which operated the relay. The reason for the dc shift of the previously quiescent ac reactor phase currents is still in want of explanation.

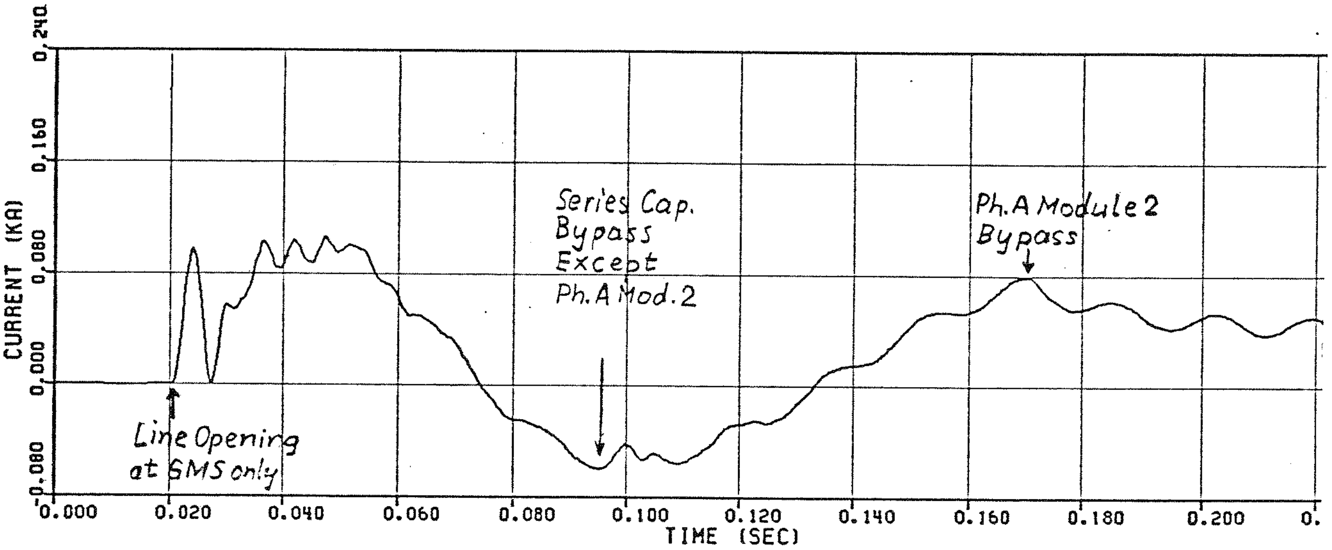
On all three of the above occurrences, the reactors were in fully energized quiescent state at the time of the external events, thus the inrush tripping suppressors supervising 32N relay were not in a state to prevent such tripouts.

Reactor Tripouts on Transformer Energization

On several occasions, shunt reactors which were fully energized in quiescent state, were tripped by interturn fault relay 32N when a large transformer bank was energized at the same station. As transformer were not modelled in the

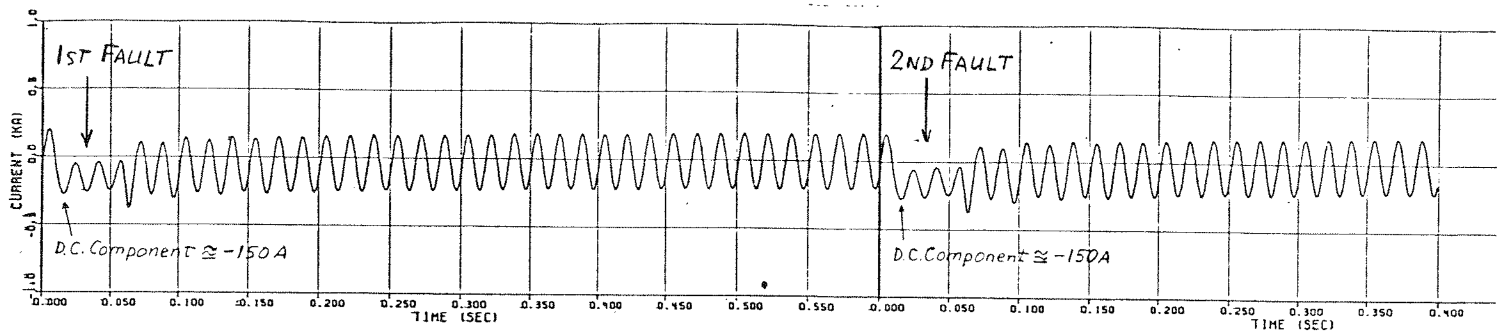


GMS REACTOR VOLTAGE - 3*V0
STUDY#16 - LINE OPENNING AT GMS, SEQ'L 5CX1 BYPASS, MOD.A2 D



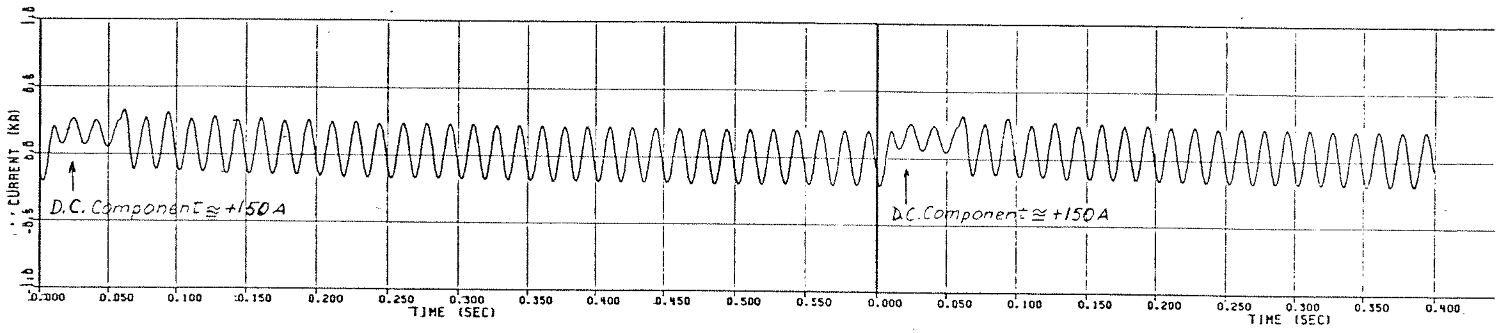
GMS REACTOR CURRENT - 3*I0
STUDY#16 - LINE OPENNING AT GMS, SEQ'L 5CX1 BYPASS, MOD.A2 D

FIG. 16 - GMS 5RX1 $3V_0$ & $3I_0$ FOR 5L1 SINGLE-ENDED OPENING AT GMS AND NON-SIMULTANEOUS SERIES CAP. BYPASS (PH. A MOD. 2 DELAY)



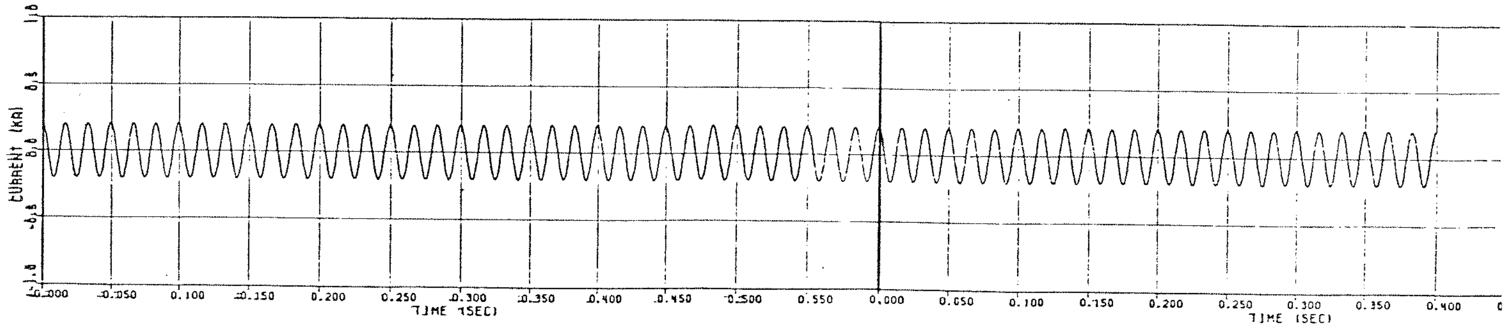
WSN REACTOR CURRENT - PHASE A
STUDY=36 - KDY=3 TEST - 2.5 CYCLE A-B WSN BUS FAULT AT VAB=0

WSN REACTOR CURRENT - PHASE A
STUDY=37 - KDY=3 TEST - 2ND FAULT, 5CX3 BYPASSED



WSN REACTOR CURRENT - PHASE B
STUDY=36 - KDY=3 TEST - 2.5 CYCLE A-B WSN BUS FAULT AT VAB=0

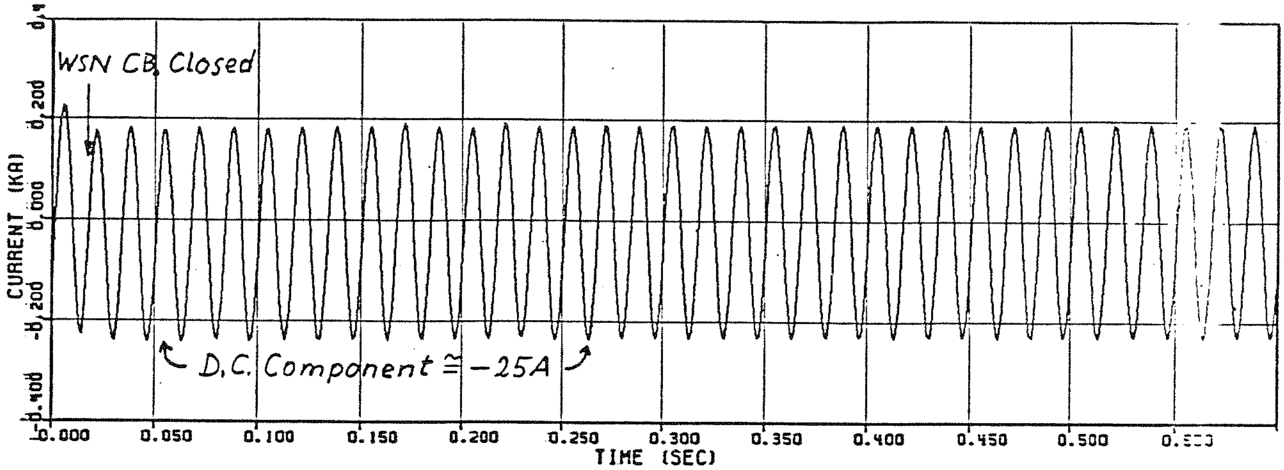
WSN REACTOR CURRENT - PHASE B
STUDY=37 - KDY=3 TEST - 2ND FAULT, 5CX3 BYPASSED



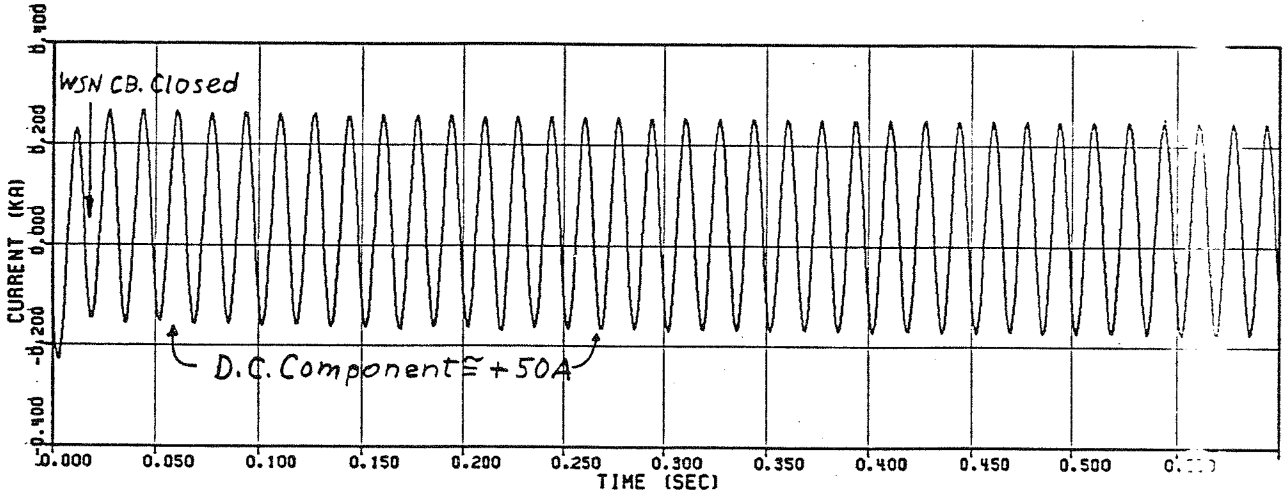
WSN REACTOR CURRENT - PHASE C
STUDY=36 - KDY=3 TEST - 2.5 CYCLE A-B WSN BUS FAULT AT VAB=0

WSN REACTOR CURRENT - PHASE C
STUDY=37 - KDY=3 TEST - 2ND FAULT, 5CX3 BYPASSED

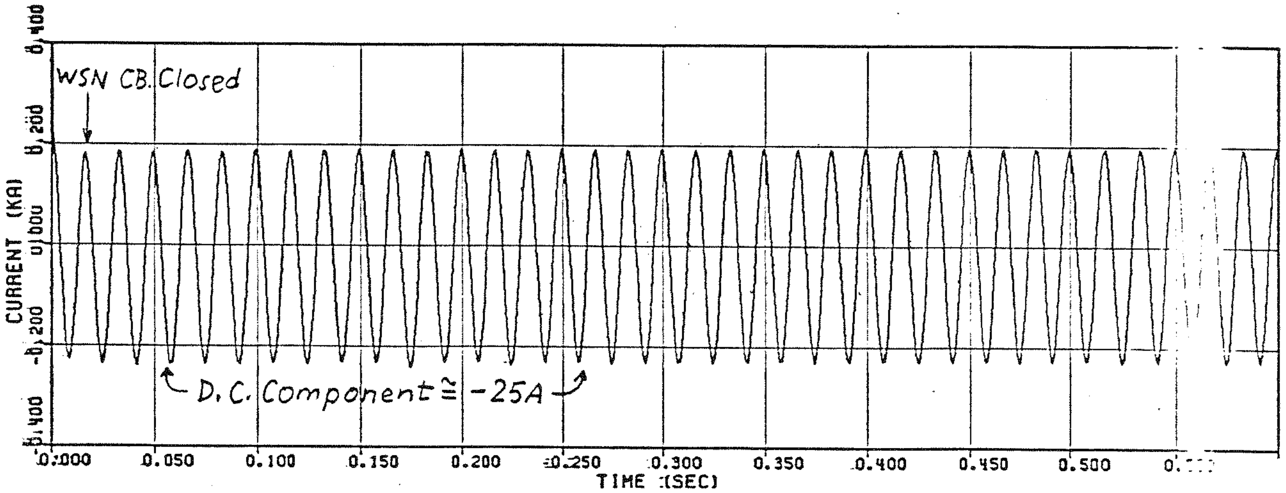
FIG. 17– REACTOR PHASE CURRENTS DURING STAGED PH. A-B FAULT IN NON-RELATED 500KV LINE



WSN REACTOR CURRENT - PHASE A
STUDY#39 - 18TH AUGUST 1982 TRIPOUT SIMULATION



WSN REACTOR CURRENT - PHASE B
STUDY#39 - 18TH AUGUST 1982 TRIPOUT SIMULATION



WSN REACTOR CURRENT - PHASE C
STUDY#39 - 18TH AUGUST 1982 TRIPOUT SIMULATION

FIG. 18 – WSN 5RX3 I_A, I_B, I_C FOR 5L11 FOLLOW-END RECLOSING AT WSN

EMTP study described previously, staged switching tests of a large transformer bank were performed, and a number of line-connected shunt reactors monitored.

Fig. 19 shows an oscillogram of the transformer energization by a circuit breaker without closing resistors. It can be seen that, although the transformer inrush currents decrease, the reactors' secondary residual currents actually increase, notably demonstrated by the 5RX3 and 5RX5 traces. This increase proceeds well beyond the time displayed in this illustration, up to about 1.5 seconds, and takes up to 10 seconds to decay to a negligible magnitude. As only secondary currents could be recorded, the waveshape of the primary currents is not known, however, the C-phase secondary current shows some dc component at the time of switching, and C-phase secondary voltage also indicates a dc displacement of the 500 kV bus voltage. Note the operation of 5RX3 interturn fault relay 32N, about 0.5 seconds following transformer energization.

Fig. 20 shows the same test repeated with a closing resistor equipped circuit breaker. The magnitude of the transformer inrush currents and their effects on the reactors have been greatly reduced, and no relay operation occurred.

The theoretical cause and effect relationship between transformer energization and reactor currents have not been established yet. However, the beneficial effect of breaker closing resistors has been demonstrated in these tests, and appropriate operating directives to use resistor-equipped breakers for transformer energization where this is possible have been established.

SURGE SUPPRESSION PROBLEMS

Table I shows for the 1977 to 1982 period fourty-four (44) reactor tripouts from "other causes", notably surges, grounds, e.m.i. in control cables. Twenty-one (21) of these occurred at one particular station, predominantly caused by tripouts originating with the trip auxiliaries of the non-electrical devices when energizing or de-energizing a reactor by circuit switcher or circuit breaker.

A research investigation backed by switching tests (Ref. 7) revealed that with the unusual grounding arrangements of these particular reactors as shown in Fig.21, namely the tank connected to ground via a current transformer, successive burst of induced high voltage at high frequencies resulted during switching. Note that at high frequencies the control cabinet is not at true ground because of the ground CT impedance. The short noise bursts may cause arcing of the microswitch contacts of the non-electrical protective devices, not long enough to operate the auxiliary relay, but sufficient to provide successive charges for the 1 microfarad surge capacitors in the control room. The charged-up surge capacitors will then discharge through the auxiliary relay, and if this discharge is of sufficient magnitude and long enough duration, the relay may trip. As remedy, 0.1 microfarad capacitors were

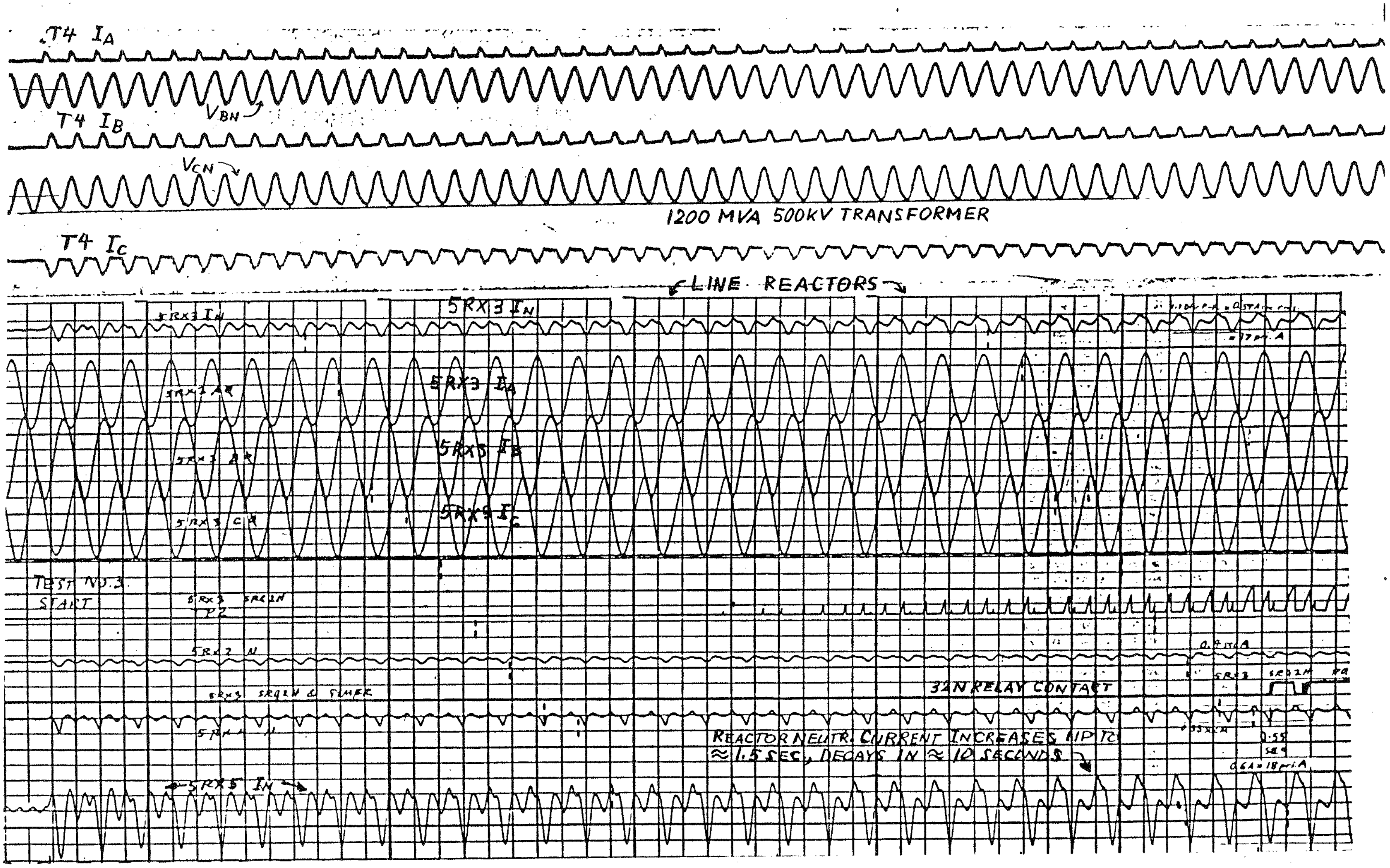


FIG. 19 - REACTOR CURRENT WHEN ENERGIZING A LARGE TRANSFORMER BY CB WITHOUT CLOSING RESISTORS

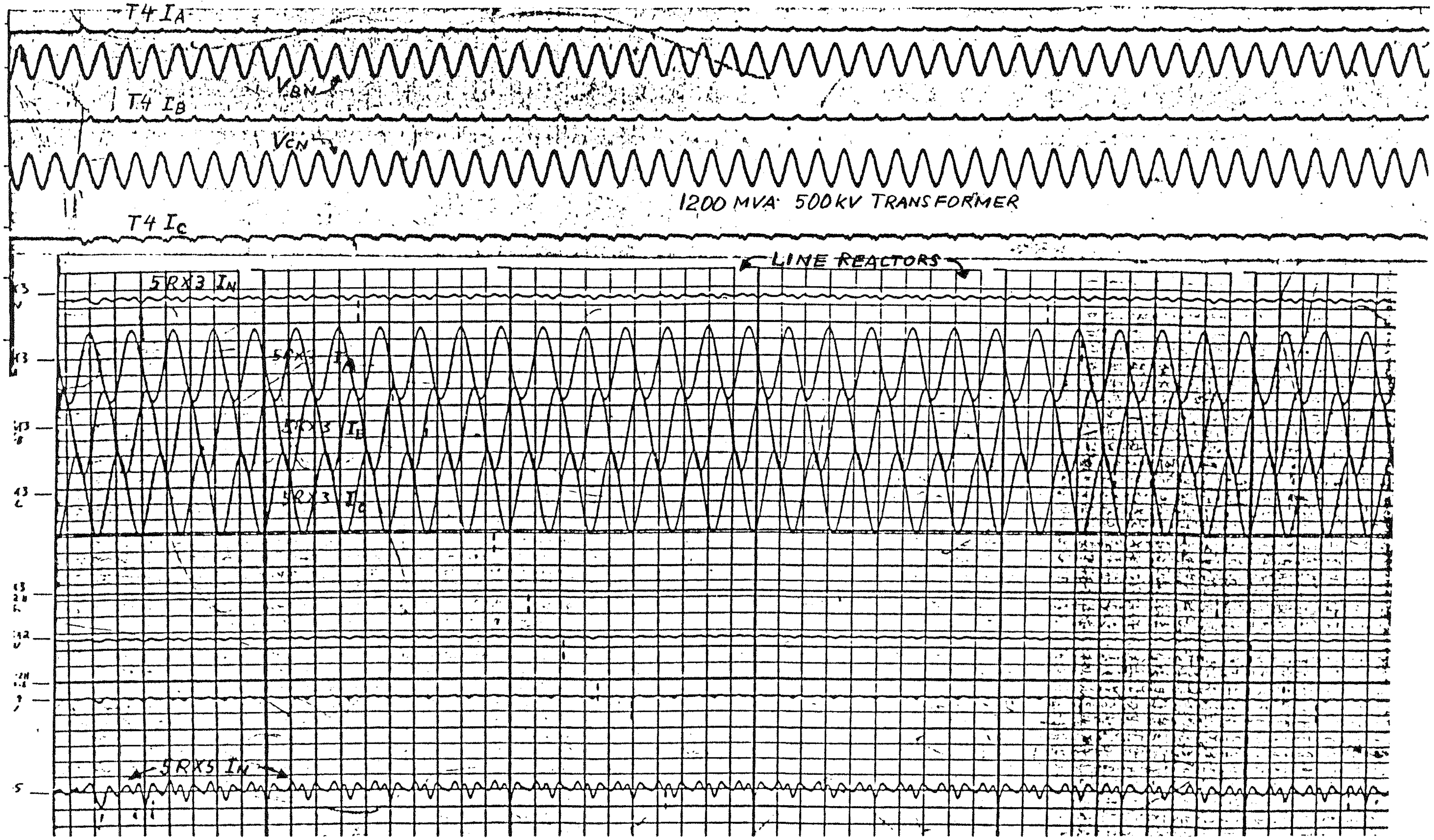


FIG. 20 – REACTOR CURRENTS WHEN ENERGIZING A LARGE TRANSFORMER BY CB EQUIPPED WITH CLOSING RESISTORS

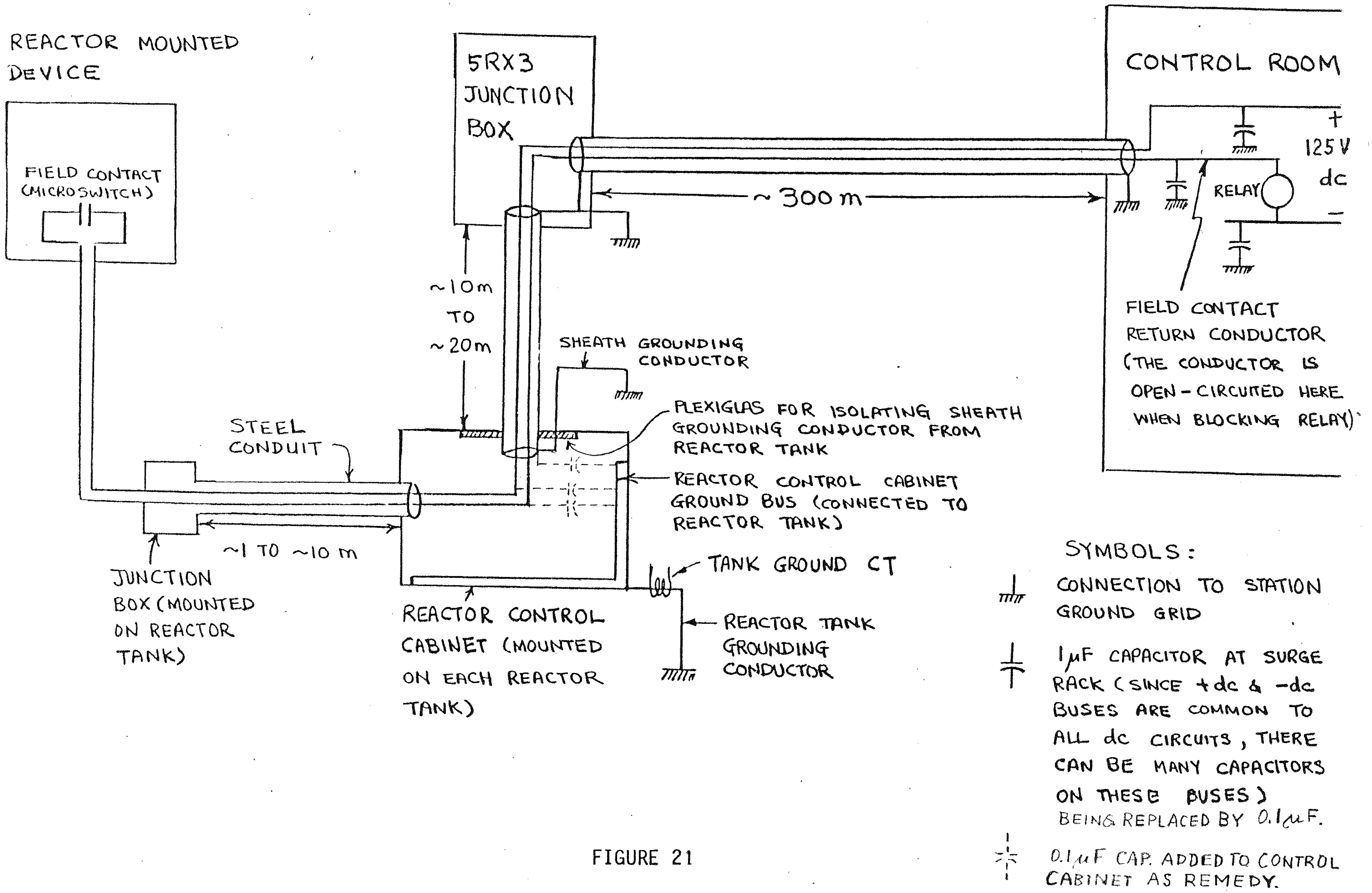


FIGURE 21

Description of a Typical Control Circuit and Cable installed in the control cabinet as shown dotted in Fig. 21, which tied the conductors and cabinet to a common ground for high frequency surges.

Another potential source of false tripouts was found in the fact that 1 microfarad surge capacitors in the control room are in a quiescently charged state of +62.5 V and -62.5 V, respectively. An accidental dc ground (as occurs sometimes when wiring work is going on in the control room) may again, cause discharge of the capacitors with the auxiliary relay being part of the discharge path, resulting in trip operation. To reduce the available discharge energy, the 1 microfarad surge capacitors are being phased out by 0.1 microfarad units.

CONCLUSIONS

The many years of operational experience, field testing, research, and computer simulations have revealed that a number of external system conditions may adversely effect the security of EHV shunt reactor protection. The most problematic phenomena are dc and low frequency components of reactor currents, during periods of de-energization or energization of the reactors themselves, or of other system equipment in the vicinity of the reactors. These components may appear in the true reactor neutral current, or they may appear in the phase currents, saturate the phase CT.s and result in differential or residual error currents. The protections adversely affected are the low-impedance differential relays (87R), the directional zero-sequence interturn fault relays (32N), and the non-directinal zero-sequence back up interturn fault relays (51N). Improperly applied or dimensioned surge protection on control cables between the reactors and the control building may also adversely affect protection security.

In particular, the findings inspired the implementation of the following specific actions or confirmed correctness of actions already taken:

1. Instantaneous element of backup interturn fault relay 51N should be disabled to avoid its erroneous operation from high-magnitude low-frequency transients upon line opening.

2. Instantaneous element of low impedance differential relay 87R to be set well above maximum expected differential error currents from transient CT saturation. Rated reactor current is good starting value, but higher settings may be necessitated by experience.

3. High impedance differential relays offer better stability and therefore are chosen for future installations.

4. Application of inrush tripping suppressor provides security for back-up interturn fault relay 51N during line out conditions and for directional zero-sequence interturn fault relay 32N during line/reactor energization.

5. Residual connection of relay 32N must be avoided to prevent erroneous operation from false residual currents due to CT saturation during system events when the inrush tripping suppressor is not activated.

6. An adjustable current level detector 50N for the sensitive directional relay 32N is advisable.

7. Individual phase impedance relays can be applied for interturn fault detection as alternatives to 32N, provided the reactor's impedance characteristic is linear.

8. Large transformers should be switched by closing resistor equipped circuit breaker to dampen the inrush currents and their effect on currents in adjacent reactors.

9. Surge protection capacitors on the control cables must be correctly applied and dimensioned.

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