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Comprehensive Aging Assessment of Circuit Breakers and Relays

Prepared by
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Prepared for
U.S. Nuclear Regulatory Commission

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Comprehensive Aging Assessment of Circuit Breakers and Relays

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ABSTRACT

As part of the NRC Nuclear Plant Aging Research (NPAR) Program, a comprehensive aging assessment was made of relays and circuit breakers. Relays and circuit breakers are important nuclear power plant equipment which are susceptible to degradation with time.

This is a Phase II NPAR report which follows the NPAR strategy. Tests on naturally aged and degraded relays and circuit breakers were performed, in-situ measurements made and current and improved methods for inspection, surveillance and monitoring (ISM) evaluated. Significant results described in this report were the identification of inspection, surveillance and monitoring methods which provide a higher level of assurance that aging will be detected and mitigated. The potential exists that implementation of the improved methods in nuclear plants would minimize the impact of aging and result in more cost effective maintenance on relays and circuit breakers.

EXECUTIVE SUMMARY

This report describes the results of a comprehensive aging assessment of relays and circuit breakers that was completed as part of the NRC Nuclear Plant Aging Research (NPAR) Program. Relays and circuit breakers were analyzed because they are important safety-related equipment which perform critical functions in the operation and control of nuclear power plants.

This is a Phase II NPAR report and the research has followed the established NPAR strategy described in NUREG-1144, Rev. 2, "Nuclear Plant Aging Research (NPAR) Program Plan."

The significant results of this research were:

- o The determination that current nuclear plant maintenance practice for the inspection of certain relays is ineffective at detecting significant aging degradation; particularly, significant aging degradation of Agastat 7012, General Electric HFA, Westinghouse MG-6, and Struthers-Dunn 219 relays was not detected using current industry practice,

- o Identified improved inspection, surveillance and monitoring (ISM) methods for relays and circuit breakers which are more effective at detecting aging degradation than current nuclear plant practice,

- o Identified less intrusive ISM methods, which have the potential for providing predictive maintenance and condition based maintenance,

- o Recommended that Infrared temperature measurement be added to the maintenance practices for auxiliary, control, protective, and timing relays and for molded case and metal clad circuit breakers,

- o Recommended that vibration signature measurement be added to the maintenance practices for auxiliary, control, and timing relays and for molded case and metal clad circuit breakers,

- o Recommended that inrush current signature measurement be added to the maintenance practices for timing relays,

- o Recommended that the procedures for instantaneous trip testing of molded case circuit breakers be clarified to assure that the instantaneous trip occurs within specification limits. A trip below this limit is significant since false instantaneous trips can preclude performance of safety-related equipment.

A comprehensive effort was undertaken to verify improved inspection, surveillance and monitoring methods (ISM). The Phase II effort was accomplished in four major elements. These were an investigation into current and advanced ISM methods, tests of aged relays and circuit breakers, tests of degraded relays and circuit breakers and in-situ tests.

Current and advanced ISM methods were ascertained by soliciting information from nuclear and non-nuclear utilities, relay and circuit breaker manufacturers and maintenance facilities.

Testing of aged devices was performed. Test specimens for each of the five relay (auxiliary, control, electronic, protective and timing) and two circuit breaker (molded case and metal clad) types were solicited from nuclear and non-nuclear utilities and manufacturers. A total of 39 specimens were tested to the current and improved ISM methods.

Eleven specimens of relays and circuit breakers were purposely degraded and the ISM methods performed after each degraded condition. The purpose of these degradation tests was to evaluate the effectiveness of the method to detect and/ or predict the level of degradation. This also provided some quantifiable parameters of the extent of degradation. The degradations chosen for each relay and circuit breaker type were purposely severe, but for the most part, did not cause total loss of operability of the device. Thus, it was an attempt to simulate the worst state of deterioration or degradation prior to failure to operate. The degradations were chosen based on a review and evaluation of the failure mode and mechanisms reported in phase I, specified by the nuclear and non-nuclear utilities, manufacturers, and experiences of the research team.

These degradation condition evaluations showed that generally accepted current nuclear maintenance practices do not always detect significant aging mechanisms. This result provides insight into the reason why failures of safety-related relays have occurred in service in spite of a comprehensive maintenance program.

The practicability of the effective methods was also evaluated at Duke Power Company's Catawba Nuclear Station and Niagara Mohawk Power Corporation's Nine Mile Point Unit 1 Nuclear Plant.

While at the plants, the research team witnessed plant maintenance personnel performing routine plant maintenance on relays and circuit breakers. Copies of procedures were obtained, results of plant maintenance tests were reviewed, and engineering and maintenance personnel were interviewed. Additionally, non-intrusive ISM methods of infrared pyrometry, infrared scanning and vibration testing were demonstrated to the plant personnel. The plant maintenance personnel and engineering staff at both plants were found to be cooperative, professional, experienced, knowledgeable and eager to discuss potential improved techniques.

It is the challenge of a good preventive maintenance program to be sensitive to the effects of aging. Early identification of age related degradation increases the probability that the safety significance of this aging is minimized. An effective inspection, surveillance and monitoring program enhances mitigation of the impact of age related degradation on the safety of nuclear plant operations.

This research has particular significance with respect to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," Information Notice 84-20, "Service Life of Relays in Safety-related Systems" and IE Bulletin 84-02, "Failures of General Electric Type HFA Relays in Use in Class 1E Safety Systems.

Generic letter 83-28, IN 84-20 and IE Bulletin 84-02 require licensees to have preventive maintenance and surveillance programs for circuit breakers and relays. This research provides information on the effectiveness of preventive maintenance methods that are required by these documents. The research showed that improved ISM methods were more effective than current industry practice at detecting aging and mitigating the effects of aging for specific devices identified in these documents.

Specific recommendations to changes in current nuclear industry practice of inspection, surveillance and maintenance on relays and circuit breakers were made.

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1. INTRODUCTION

This report describes the results of a comprehensive aging assessment of relays and circuit breakers that was completed as part of the NRC Nuclear Plant Aging Research (NPAR) Program. Relays and circuit breakers were analyzed because they are important safety-related equipment which perform critical functions in the operation and control of nuclear power plants.

This is a Phase II NPAR report. The research has followed the established NPAR strategy described in NUREG-1144, Rev. 2, "Nuclear Plant Aging Research (NPAR) Program Plan."

Relays and circuit breakers are important nuclear power plant equipment which are susceptible to degradation with time. In the last 10 years, the failures of relays and circuit breakers at nuclear plants have resulted in many NRC notices and bulletins. For instance, an age related failure of circuit breakers resulted in an Anticipated Transient Without Scram (ATWS), noted in Bulletin 83-01 and Generic Letter 83-28. Several instances of shorter than anticipated life for various safety-related relays were noted in IE Bulletin 84-02 and IE Notices 81-01, 82-04, 82-13, 84-20 and 88-98. Recent age related circuit breaker problems have been noted in NRC Information Notices 90-41 and 90-43.

Information notice 84-20, and IE Bulletin 84-02 had notified the nuclear industry that service life of all relays in the energized state was shorter than when in a cycled or de-energized application. Additionally, specific experience on GE HFA auxiliary relays, Agastat Timing relays and GTE Sylvania control relays had showed that energized relays were experiencing end-of-service-life failures at intervals short of the manufacturer's expected or specified service life. Generic letter 83-28 had requested licensees to maintain a program that includes specifications on the qualification testing for expected safety service conditions to support the life limits of life recommended by the suppliers of components in safety-related systems. IN 84-20 advised that preventive maintenance programs should recognize the application dependent (energized / de-energized) service life of relays from all manufacturers and that it may be prudent to increase the frequency of surveillance activities in systems where the current surveillance interval is not small in comparison with the life of relays used in those systems. It was stated that, as an example, an 18 month surveillance interval for a component with only a 4.5 year service life may not be appropriate.

Additionally, problems have surfaced with respect to the pedigree and integrity of circuit breakers. NRC Bulletin 88-10 resulted from the finding that counterfeit and refurbished molded case circuit breakers had found their way into nuclear plants. Several instances of commercial grade relays and circuit breakers have mistakenly been used as seismically qualified (NRCB 88-01, IEN 83-19, IEN 87-66 and IEN 88-14). It was noted in NRC IN 88-14 that older plants may contain vintages of relays which are more seismically vulnerable than newer models.

Failure of relays and circuit breakers can lead to loss of mitigating capability and inadvertent actuation as noted in IEN 85-82 and IEB 79-11. Circuit breakers which fail to isolate faults can cause significant damage to associated equipment, increase the chance of fires and lead to the loss of multiple systems. Failure of protective relays to detect abnormal voltage conditions can allow reduced voltage conditions to exist thus affecting equipment operability and preventing loading of the diesel generator.

Since the failure of relays and circuit breakers have and could have significant safety impacts, it was important to identify and characterize the mechanisms of material and component degradation during service. Methods of inspection, surveillance, condition monitoring and maintenance were evaluated as a means of managing aging effects that may impact safe plant operation.

This research resulted in some significant results.

- It was determined that current nuclear plant maintenance practice for the inspection of Agastat 7012, General Electric HFA, Westinghouse MG-6 and Struthers-Dunn 219 relays was ineffective at detecting significant aging degradation,

- Improved ISM methods were identified which are more effective at detecting aging degradation in relays and circuit breakers than current nuclear plant practice,

- The improved ISM methods are less intrusive than current nuclear practice and have the potential for improving predictive maintenance and initiating condition based maintenance,

- It was observed that several of the aging degradations caused significant and some excessive increases in temperatures, these temperature increases greatly shorten the service life and are undetectable by current maintenance practice, therefore infrared temperature measurement was recommended to be added to the maintenance practices for auxiliary, control, protective and timing relays and for molded case and metal clad circuit breakers,

- Similarly, vibration signature measurement was recommended to be added to the maintenance practices for auxiliary, control and timing relays and metal clad and molded case circuit breakers, to improve the effectiveness of maintenance to detect significant aging degradation,

- For timing relays, it was recommended that inrush current signature measurement be added to current maintenance practices because of its sensitivity to aging degradation on timing relays,

- For molded case circuit breakers, it was recommended that the procedures for instantaneous trip testing be clarified to assure that the instantaneous trip occurs within specification limits. A trip below this limit is significant since false instantaneous trips can preclude performance of safety-related equipment.

This section describes the background of the research strategy, describes the objectives of the research and defines the testing performed on naturally aged and degraded equipment in order to determine the methods most effective for detection of age degradation.

1.1 Background

The Nuclear Plant Aging Research (NPAR) Program is intended to resolve technical safety issues related to the aging degradation of electrical and mechanical components, safety systems, support systems, and civil structures used in commercial nuclear power plants. The aging period of interest includes the period of normal licensed plant operation, as well as the period of extended plant life, that may be requested in utility applications for license renewals.

Emphasis has been placed on identifying and characterizing the mechanisms of material and component degradation during service and utilizing research results in the regulatory process. The research includes evaluating methods of inspection, surveillance, condition monitoring, and maintenance as a means of managing aging effects that may impact safe plant operation. Specifically, the goals of the program are:

- Identify and characterize aging effects that, if unchecked, could cause degradation of components, systems, and civil structures and thereby impair plant safety.

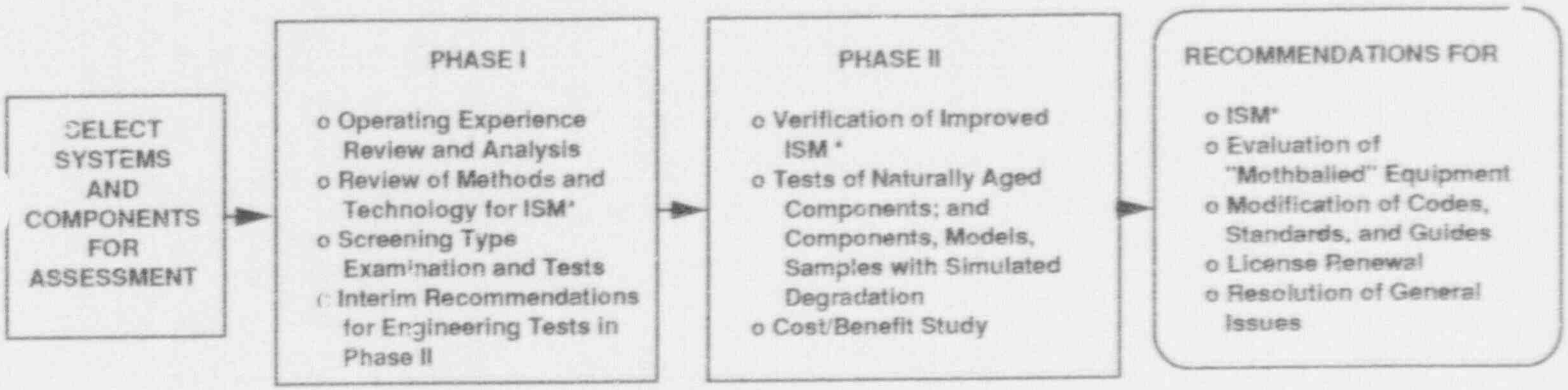
- o Identify methods of inspection, surveillance, and monitoring, and evaluate residual life of components, systems, and civil structures that will ensure timely detection of significant aging effects before loss of safety function.

- o Evaluate the effectiveness of storage, maintenance, repair, and replacement practices in mitigating the rate and extent of degradation caused by aging.

The NPAR Program is based on a phased approach to research. The objectives of the Phase I study NUREG/CR-4715, "An Aging Assessment of Relays and Circuit Breakers and System Interactions" were: to identify and characterize aging and wear effects; to identify failure modes and causes attributable to aging; and to identify measurable performance parameters, including functional indicators. The functional indicators have a potential use in assessing operational readiness of a component, structure, or system in establishing degradation trends, and in detecting incipient failures.

The objectives of this Phase II study are: perform in depth engineering studies and aging assessments based on in-situ measurements; perform post-service examination and tests of naturally aged/degraded components; identify improved methods for inspection, surveillance, and monitoring, or for evaluating residual life; and make recommendations for utilizing research results in the regulatory process. Figure 1-1 illustrates the NPAR research approach.

The aging assessments of the relays and circuit breakers selected for evaluation primarily involve two stages. The first stage, Phase I, was based on readily available information from public and private data bases, vendor information, open literature, utility sources, and expert opinions. The products of the Phase I analysis include: an identification of failure modes; a preliminary identification of failure causes due to aging and service wear degradation; and a review of current inspection, surveillance and monitoring methods, including manufacturer-recommended surveillance and maintenance practices. Performance parameters or functional indicators potentially useful in detecting degradation were also identified and preliminary recommendations were made regarding inspection, surveillance, and monitoring methods. In Phase I, recommendations were developed to identify detailed engineering tests and analyses to be conducted in Phase II. In the Phase I evaluation it was decided that a Phase II assessment was warranted.



*ISM -- Inspection, surveillance and monitoring methods

Figure 1-1 : NPAR Research Approach

1.2 Objectives

The objectives of Phase II are:

- o review and verification of improved inspection, surveillance and monitoring methods
- o in-situ examination and data gathering for operating equipment
- o tests of naturally aged components or components with simulated degradation
- o evaluation of the role of maintenance in mitigating aging degradation
- o evaluation of service life prediction methods

1.3 Scope

The component and equipment which constituted the scope of work were five categories of relays.

The relay categories were defined in Phase I as follows:

- o auxiliary relays - actuated by protective relays for high current applications
- o control relays - used in nuclear protective system logic
- o electronic relays - solid state device used in protective or control relay applications
- o protective relays - protects plant power system from effects of electrical overloads, faults and transients
- o timing relays - delays operating function until initiating condition has existed for a selected time

Additionally, the scope of work included circuit breakers. The circuit breaker categories were defined in Phase I as follows:

- o molded case circuit breakers - 480 volt and below most prevalent, used to supply individual circuits and feeders for low voltage AC and DC distribution

- metal clad 480 volt circuit breakers - used in the power supply to 480 volt distribution bus as well as to feed individual circuits for major safety-related equipment such as medium-sized motors

- metal clad 4KV circuit breakers - these are housed in large metal cabinets and are used for main circuit breakers for large safety-related equipment and the emergency power buses

A total of 39 specimens were tested in this research. Table 1-1 shows the listing of specimens and the approximate age of each specimen at the time the research started.

The specimens were obtained from a variety of sources. These included several nuclear power plants such as Diablo Canyon, Peach Bottom and Shippingport, non-nuclear facilities such as Champion Paper Mill and Huntsville Utilities and manufacturers. Additional relays and circuit breakers were evaluated at two nuclear plants, Duke Power Company's Catawba and Niagara Mohawk Power Corporation's Nine Mile Point Unit 1. Catawba was approximately 12 years old and Nine Mile Point Unit 1 was approximately 25 years old.

Section 2 summarizes the elements of Phase I and discusses in detail the Phase II elements. The Phase II elements consisted of an industry search for current and advanced inspection, surveillance, condition monitoring and maintenance (ISM) methods applicable to relays and circuit breakers; tests of naturally aged and degraded components; and in-situ efforts during which nuclear plant maintenance of relays and circuit breakers were reviewed and evaluated. Testing was performed in two sets. In the first set, all thirty-nine new and aged relays and circuit breakers were evaluated using current and advanced ISM methods. In the second set of tests, eleven of the sample specimens (denoted with an asterisk in Table 1-1) were purposely degraded and the ISM techniques repeated after each degraded condition, in order to determine the effectiveness of the techniques. Additionally, in-situ efforts were performed in which plant personnel were observed performing maintenance of relays and circuit breakers. The research team demonstrated some of the advanced techniques and the practicability of the methods were assessed. In Section 3 the results of testing aged devices are presented. Section 4 contains the results of the degradation tests and the results of in-situ efforts.

Section 5 describes the useful ISM methods for each of the relay and circuit breaker types based on the age, degradation and in-situ tests. Service life prediction is discussed in Section 6. The significance of the research for the NRC and industry standards and the conclusions and recommendations are discussed in Section 7.

Table 1-1 Relay and Circuit Breaker Specimen List

Type	Manufacturer	Model	Age (years)
Auxiliary Relay	General Electric	12HFA51	New
	*" "	12HFA51	4
	*" "	12HFA51	18
	Westinghouse	MG-6	New
	*" "	MG-6	27
	" "	MG-6	27
Control Relay	Klockner-Moeller	DIL00Lb22	6
	" "	DIL00Lb22	6
	*Struthers Dunn	219 XDX-P	New
	" "	219 XDX-P	12
	" "	219 XDX-P	12
	Westinghouse	ARD4S	6
	" "	ARD4S	6
Electronic Relay	*Basler	BE1-1	New
Protective Relay	*General Electric	12IAC53B101A	10
	" "	12IAC53B101A	13
	" "	12IAC53B101A	24
	*Westinghouse	CO	30
	" "	CO	30
Timing Relay	Agastat	E7012AB002	4
	*"	7012AA	8
	"	7012AA	8
	"	7012AC	8
	"	F7012AC	10
	"	2412AN	23
	"	2412AD	23
Molded Case Circuit Breaker	General Electric	TFJ224150	New
	*Square D	FAL36070	6
	"	KAL36150	6
	*ITE	KMB2F800	8
	Klockner-Moeller	NZMH6-63	10
	"	NZMH6-100	10
	Westinghouse	HFB3045ML	18
	" "	HFB31550ML	18
	" "	HFB31550ML	18
	" "	AB DE-ION	30
	" "	AB DE-ION	30
Metal Clad Circuit Breaker	Westinghouse	DB-25	25
	*General Electric	AK-2S-25	29

* Signifies that device was also used in degraded conditions tests.

2. RESEARCH ELEMENTS

The NPAR Program research for relays and circuit breakers was a two phased effort following the established NPAR strategy. Phase I was reported in NUREG/CR-4715, "An Aging Assessment of Relays and Circuit Breakers and System Interactions." Phase II is the subject of this report. In this section the research elements of Phase I are summarized, followed by the discussion of the Phase II research elements.

2.1 Phase I Research

The objectives of the Phase I study were: to identify and characterize aging and wear effects; to identify failure modes and causes attributable to aging; and to identify measurable performance parameters, including functional indicators.

In Phase I, the safety-related relay and circuit breaker types under study were identified. They were relay types: auxiliary, control, electronic, protective, and timing and circuit breaker types: molded case and metal clad.

The aging assessments of relays and circuit breakers selected for evaluation in Phase I, were based on readily available information from public and private data bases, vendor information, open literature, utility sources, and expert opinions. The products of the Phase I analysis include: an identification of failure modes; a preliminary identification of failure causes due to aging and service wear degradation; and a review of current inspection, surveillance and monitoring methods, including manufacturer-recommended surveillance and maintenance practices. Performance parameters or functional indicators potentially useful in detecting degradation were also identified and preliminary recommendations were made regarding inspection, surveillance, and monitoring methods. In Phase I, recommendations were developed to identify detailed engineering tests and analyses to be conducted in Phase II. In the Phase I evaluation it was decided that a Phase II assessment was warranted.

It was noted in Phase I that even though relays and circuit breakers are often located in mild environments in nuclear plants, electrical, mechanical, thermal and environmental stresses have been shown to cause aging degradation. Failure information was gathered from many sources, including NRC's Licensee Event Report (LER) system, the Institute for Nuclear Power Operations' (INPO) Nuclear Plant Reliability Data System (NPRDS), and Oak Ridge National Laboratory's In-Plant Reliability Data System (IPRDS). It was recognized that limitations exist on these sources and that reporting requirements differed. Considering this, qualitative information on relay and circuit breaker failures was gl aned from these sources.

The significant conclusions were that failure rates were low but energized relays failed at a greater rate than non-energized. Additionally, certain relay and circuit breaker types, for instance, protective relays, had a tendency towards increased failure with age.

2.2 Phase II Research

In Phase II, a comprehensive effort was undertaken to verify improved inspection, surveillance and monitoring methods (ISM). The Phase II effort was accomplished in four major elements. These were an investigation into current and advanced ISM methods, tests of aged relays and circuit breakers, tests of degraded relays and circuit breakers and in-situ tests.

2.2.1 Nuclear Industry Practice

Current and advanced ISM methods were ascertained by soliciting information from nuclear and non-nuclear utilities, relay and circuit breaker manufacturers and maintenance facilities. Wyle Laboratories was supported in this effort by a subcontractor, General Electric Company's Apparatus and Engineering Services Group, which routinely inspects and maintains this type of equipment. In addition to specific solicitations for information on nuclear practice directly to nuclear plants, the Electric Power Research Institute (EPRI) and NUMARC aided by soliciting information from their member utilities. Supplementing these solicitations, procedures on relay and circuit breaker maintenance were also gathered in the in-situ effort at two nuclear plants. This was further discussed later in this section.

The result of the solicitations was the information that, depending on relay or circuit breaker style, nineteen ISM methods are in current use and constitute the state-of-the-art. These are shown in Table 2-1 with respect to type of relay and circuit breaker. Also, sixteen methods were designated as advanced methods which were classified as not yet in use on relays and circuit breakers in nuclear plants. These advanced methods are shown in Table 2-2.

Table 2-1. Current ISM Methods in Plant Procedures
for Relays and Circuit Breakers

ISM	Device Type						
	AUX	CONT	ELEC	PROT	TMNG	MLDCS	MTLCD
Visual Inspection	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Pick-up Voltage	Yes	Yes			Yes		
Drop out Voltage	Yes	Yes					
Operation	Yes					Yes	
Time / Current Characteristic			Yes	Yes			
Induction / Overcurrent Pick-up			Yes	Yes			
Target and Seal-In				Yes			
Instantaneous Trip			Yes	Yes		Yes	Yes
Operating Current				Yes			
Timing					Yes		
Pole Resistance						Yes	Yes
Insulation Resistance						Yes	Yes
Mechanical Actuation						Yes	Yes
100% Rated Current Hold-in						Yes	
135% Rated Current Hold-in						Yes	
300 % Overcurrent						Yes	
Long Time Delay Overcurrent							Yes
Short Time Delay Overcurrent							Yes
Lubrication Inspection							Yes

Legend:

AUX : Auxiliary Relay
CONT: Control Relay
ELEC: Electronic Relay
PROT: Protective Relay
TMNG : Timing Relay
MLDCS: Molded Case Circuit Breaker
MTLCD: Metal Clad Circuit Breaker

2.2.2 Tests on Aged Relays and Circuit Breakers

The next major element was testing of aged devices. Test specimens for each of the five relay (auxiliary, control, electronic, protective and timing) and two circuit breaker (molded case and metal clad) types were solicited from nuclear and non-nuclear utilities and manufacturers. A total of 39 specimens were tested. The test specimens were representative of nuclear safety-related relays and circuit breakers. They represented the mix of product types and manufacturers which were utilized in the industry. Relay manufactures were : Agastat, a division of Amerace Corporation; Basler Electric Company; General Electric Company; Klockner-Moeller Corporation; Struthers Dunn, Incorporated; and Westinghouse Electric Corporation. Circuit breaker manufacturers were : I-T-E Electrical Products, a division of Siemens-Allis,

Table 2-2. Advanced ISM Methods

Contact Resistance
Coil Resistance
Magnetic Flux
Insulation Resistance (relays)
Inrush Current
Holding Current
Infrared Pyrometry
Infrared Scanning
On-contact Temperature
Current Surge Comparison
Vibration Testing
Acoustic Testing
Ion Detection
Zero Check (protective relays)
600 % Overload (molded case breakers)
Dielectric (molded case breakers)

Incorporated; General Electric Company; Klockner-Moeller Corporation; Square D Company; and Westinghouse Electric Corporation.

Each type of relay and circuit breaker has unique attributes which were verified by specific methods, such as timing on timing relays and 300% overcurrent on molded case breakers. Additionally, some methods were more generic and thus were applicable to most relay and circuit breaker types. Examples of generic methods were visual inspection, contact resistance and insulation resistance. This information was utilized in the planning for the tests on aged devices and the degraded tests.

Detailed test plans (References 10 through 16) were prepared for the five relay and two circuit breaker types. These test plans were reviewed by the NRC, Brookhaven National Laboratories, NUMARC and EPRI. They contained step by step instructions on how the tests were to be performed and detailed checklists were prepared on which to record the data generated.

The following paragraphs describe the ISM methods which were evaluated. The specific ISM methods evaluated for each of the relays and circuit breakers tested have been listed in Table 2-3 for each relay and circuit breaker type.

Table 2-3. Phase II ISM Methods Evaluated

ISM	Device Type AUX	CONT	ELEC	PROT	TMNG	MLDCS	MTLCD
Visual Inspection	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Contact Resistance	Yes	Yes	Yes	Yes	Yes		
Coil Resistance	Yes	Yes	Yes	Yes	Yes		
Magnetic Flux	Yes	Yes		Yes	Yes		
Pick-up Voltage	Yes	Yes			Yes		
Drop out Voltage	Yes	Yes			Yes		
Inrush Current	Yes	Yes		Yes	Yes		
Holding Current	Yes	Yes			Yes		
Infrared Pyrometry	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Infrared Scanning	Yes	Yes	Yes	Yes	Yes	Yes	Yes
On-contact Temperature	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Current Surge Comparison	Yes	Yes		Yes	Yes		
Vibration Testing	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Acoustic Testing	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Ion Detection	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Time / Current Characteristic			Yes	Yes			
Induction / Overcurrent Pick-up			Yes	Yes			
Target and Seal-In				Yes			
Instantaneous Trip			Yes	Yes		Yes	Yes
Operating Current				Yes			
Zero Check				Yes			
Timing					Yes		
Pole Resistance						Yes	Yes
Insulation Resistance	Yes	Yes		Yes	Yes	Yes	Yes
Mechanical Actuation						Yes	Yes
100% Rated Current Hold-in						Yes	
135% Rated Current Hold-in						Yes	
300 % Overcurrent						Yes	
600 % Overload						Yes	
Dielectric						Yes	
Long Time Delay Overcurrent							Yes
Short Time Delay Overcurrent							Yes
Lubrication Inspection							Yes

Legend:

AUX : Auxiliary Relay
CONT: Control Relay
ELEC: Electronic Relay
PROT: Protective Relay
TMNG : Timing Relay
MLDCS: Molded Case Circuit Breaker
MTLCD: Metal Clad Circuit Breaker

Visual Inspection

Visual inspection of devices was performed to detect obvious visible degradation and damage. Visual inspection was performed before any testing was conducted to accurately record the condition of the device including name plate information, condition of coils, contacts, conductors, and wire insulation. Each device was also checked for signs of overheating including odors, moisture intrusion, foreign debris and loose connections and parts. The visual inspection was performed with a pen light and approximately 10 times magnification.

Additionally, the protective relays were visually inspected for foreign debris including metal filings and dirt on the induction disk and drag magnet.

Contact Resistance

The resistance of each contact and pole was measured by the Kelvin method to determine their integrity. Excessive contact or pole resistance indicated oxidation and / or contact wear.

Contact resistance was measured twice, in the as received condition and after ISM methods of pick-up, drop out, inrush and holding current to evaluate the effects of operation on the resistance.

Coil Resistance

Coil resistance was measured on each relay at four different times during the tests on aged devices. The four times were : first, in the as received condition, at the start of the ISM methods; second, after the relay had been energized for 2 hours; third, after the coil had been allowed to cool to ambient after ISM methods of pick-up, drop out, inrush and holding current; fourth, after the relay had been energized for 2 hours. The coil resistance was recorded at five second intervals for one minute.

The coil resistance was measured in this fashion to assess differences in hot coil resistance caused by energization versus ambient measurements and to evaluate the effect of repeated operations which were performed in the course of performing the other ISM operations. Information notice 84-20, and IE Bulletin 84-02 had notified the nuclear industry that service life of all relays in the energized state was shorter than when in a cycled or de-energized application. Additionally, specific experience on GE HFA auxiliary relays, Agastat Timing relays and GTE Sylvania control relays had showed that energized relays were experiencing end-of-service-life failures at intervals short of the manufacturer's expected or specified service life. Generic letter 83-28 had requested licensees to maintain a program that includes specifications on the qualification testing for expected safety service conditions to support the life limits of life recommended by the suppliers of components in safety systems. IN 84-20 advised that preventive maintenance programs should recognize the application dependent (energized / de-energized) service life of relays from all manufacturers and that it may be prudent to increase the frequency of surveillance activities in systems where the current surveillance interval is not small in comparison with the life of relays used in those systems. It was stated that, as an example, an 18 month surveillance interval for a component with only a 4.5 year service life may not be appropriate. Thus the measurement of coil resistance in hot and ambient conditions and changes over a one minute energization period would allow calculations of coil heat rise and if resistances and heat rise change, could be indicative of approaching end of service life.

Magnetic Flux

Magnetic Flux was performed by measuring the strength of the magnetic field with a gaussmeter. Magnetic flux of the coil field was measured to determine shifts in the field due to coil current changes from shorted coil turns and magnetic core changes from aging or obstruction such as a blocked armature. Magnetic field measurements were performed using a Bell 615 Gaussmeter with connecting axial probe used to locate the area of highest flux. This area was marked with a marker which identified the location and orientation of the probe in order to locate the area in later tests.

Pick-up Voltage

Pick-up voltage was determined by slowly applying voltage to the device and recording the voltage at which the contacts change state. The sequence of contact closure was also noted when discernable.

Drop Out Voltage

Drop out voltage was obtained by slowly reducing the voltage from nominal and recording the voltage at which the last contacts changed state.

Vibration and Acoustic

In vibration testing, a vibration signature was obtained to detect loose, worn or otherwise improperly operating mechanisms. Vibration signatures were obtained by mounting nine accelerometers, on a device and its mounting surface. Figure 2-1 shows a typical arrangement of the accelerometers. Vibration signatures were taken during device changes of state in the tests on aged devices and degradation tests. The accelerometers were mounted to the enclosure door with studs and to the device with special adhesive coated accelerometer mounting discs. The resulting vibration signatures were captured on tape, transferred to a computer data base for storage, analysis and trending. They were then analyzed in the time domain and frequency domain.

The acoustic testing, was performed in conjunction with the vibration testing. A microphone was utilized to obtain an acoustic signature to detect loose, worn or otherwise improperly operating mechanisms. The acoustic signature was captured on tape, transferred to a computer data base for storage, analysis and trending.

Temperature and Infrared Measurements

Temperatures were measured using three different methods. They were infrared pyrometry, infrared scanning and on-contact temperature. Infrared Pyrometry consisted of obtaining temperature measurements of a device using an infrared thermal pyrometer. A hand held Raytek Ranger II was utilized. Infrared scanning was performed with three systems from two manufacturers. AGEMA Infrared Systems provided a Thermovision 870 and a 470 system. Inframetrics, Inc. provided a Thermal Imaging System Model 600. The infrared scanners have the ability to produce infrared images as photographs and can also save the images into computer data bases for storage, trending and analysis. Agema's data was analyzed using AGEMA CATS 2.0 image analysis software. The temperatures at the accessible surface of devices was measured with a Luxtron 755 Fluoroptic Temperature Probe.

The infrared measuring instruments were approximately 24 inches from the device being measured. Temperature measurements were recorded after the devices were energized for a period of one hour and were obtained for several locations on all devices in each of three views, as shown in Figure 2-2. The three views were normal to the device, simulating the ability to take measurements at a location approximately perpendicular to the normal mounting location. Additionally, views of 45° to the right and left of the normal view were taken. These were done to evaluate the changes in

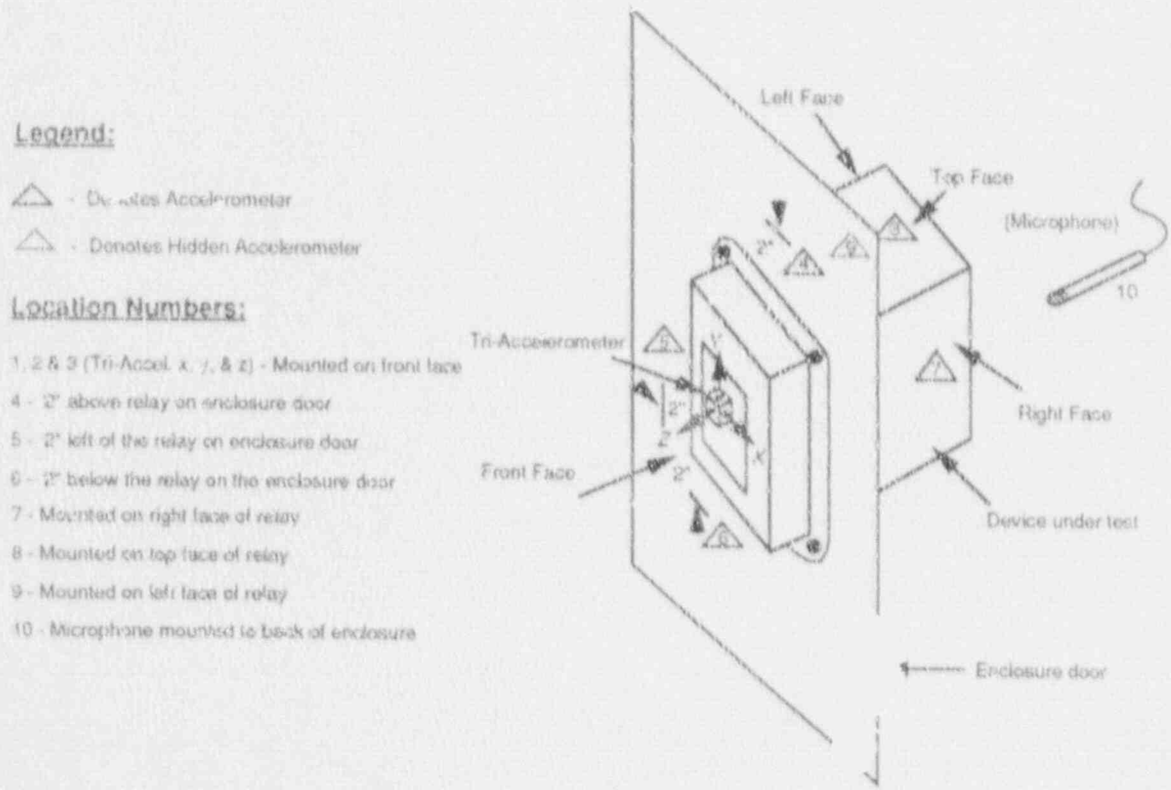
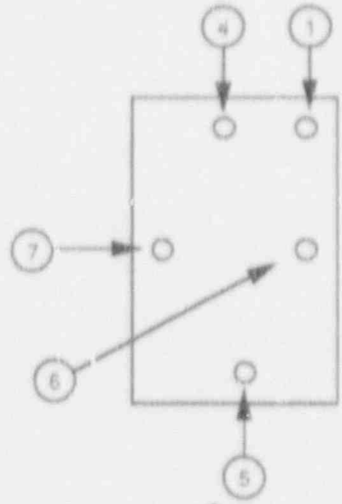


Figure 2-1. Typical Vibration and Acoustic Measurement Locations

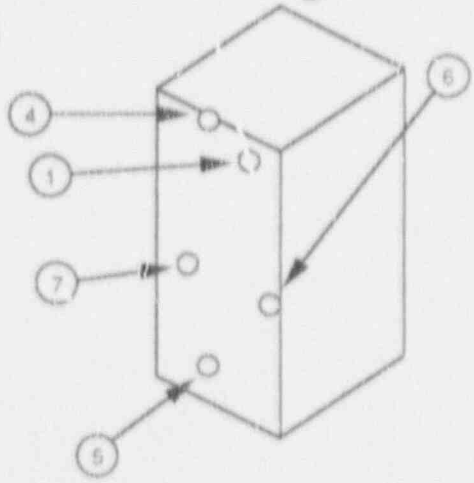
View 1 - Normal to the device under test

1. emissivity tape
2. each visible terminal
3. hottest spot
4. middle of top edge
5. middle of bottom edge
6. middle of right edge
7. middle of left edge



View 2 (45 degrees to right of view 1)

1. emissivity tape
2. each visible terminal
3. hottest spot
4. middle of top edge
5. middle of bottom edge
6. middle of right edge
7. middle of left edge
8. hottest spot from view 1



View 3 (45 degrees to left of view 1)

1. emissivity tape
2. each visible terminal
3. hottest spot
4. middle of top edge
5. middle of bottom edge
6. middle of right edge
7. middle of left edge
8. hottest spot from view 1

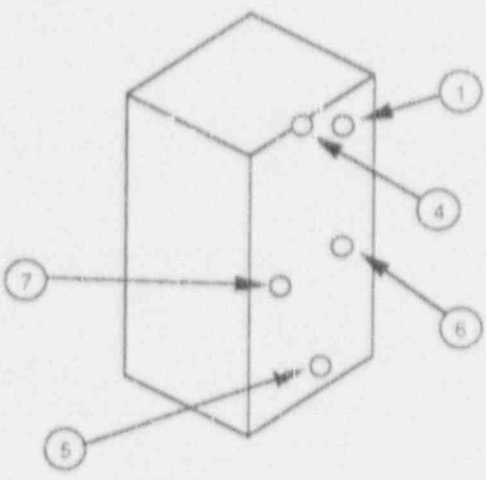


Figure 2-2. Temperature Measurement Locations

temperature visible from different angles and thus the necessity for more than one view to capture the important temperatures on each type of device.

Important parameters of distance to the target and emissivity, the relative power of a surface to emit heat by radiation, were recorded. As shown in Figure 2-2, specific locations on each device were measured as well as the hottest spot in each view and the hottest spot from the normal view. One of the locations was of a known emissivity tape in order to evaluate emissivity effects.

Additionally, six more views of the auxiliary and protective relays were taken. Temperatures were obtained in three views on the back of these devices, because these devices were mounted through an enclosure panel. The front is visible outside the panel and the back is visible when the panel door is open, see Figure 2-3. The auxiliary and protective relays had removeable covers. In order to ascertain the necessity for cover removal when performing temperature measurements, temperatures were also measured in three views on these devices with the covers removed.

Inrush Current and Holding Current

Inrush current was determined by the use of current probes and oscilloscopes to measure the peak current through the coil when the coil was first energized. The holding current was obtained after the inrush current transient using the same equipment. It represented the steady state current in the energized coil.

Current Surge Comparison

Current surge comparison testing was performed using a modified Baker DW-8505 Advanced Impulse Winding Tester and a Baker supplied current transformer. A high voltage, short duration impulse designed to stress turn-to-turn insulation, was imposed into the winding under test and the voltage decay waveform generated by the windings in response to the impulse was displayed on a CRT screen showing its Q-factor and inductance. The waveform from the inductor under test was superimposed upon the waveform from a previously saved master waveform for comparison.

In order to verify that the surge tester could be used on relays, samples were sent to Baker to test. Baker reported information on testing relays. For instance, the GE IAC protective relay was reported to have a coil with low turns count, heavy wire, low resistance (40 milliohms) and low inductance (148 microhenries). The original waveforms showed that with the ring capacitance in the DW-8505, the waveform damps out without one

Figure 2-3. Example of a Panel Mounted Device,
(Front visible with door closed and
Back visible with door open)

cycle of ringing. To improve the waveform, the coil was tested through an impedance transformer resulting in a waveform which rings for a couple of cycles. Most of the ringing was due to the transformer, however a comparison could be made between the two signature patterns superimposed on a print.

Ion detection

Ion detection was the detection of the presence of ionizing gases by utilizing ionization smoke detectors mounted above each specimen during the tests which required energization of the specimens. Two styles of smoke detectors were utilized. They were BRK model 83R, BRK Electronics, a division of Pittway Corporation and Probe Model No. 101, Southwest Laboratories, Inc. Any outgassing caused by equipment aging or more rapid outgassing caused by overheating of insulating materials, would be detected when air samples are drawn across an ionization plate. After the detection of a threshold of ion particles, a transistor causes an alarm.

Insulation Resistance

Insulation resistance was performed by applying 500 VDC with a General Radio Megohmmeter and measuring the resistance between adjacent connections and connections to ground. The resistance of normally isolated parts was measured to assure high insulating characteristics.

Timing

Timing was performed on timing relays to detect changes in the time delay characteristics. This was performed by applying a voltage and recording the time delay before the contacts change state.

Circuit Breaker Trip

Overcurrent trip tests for short and long time delay were performed on metal clad circuit breakers. . The short time delay overcurrent test, which tests the short time delay device, was performed at 2500 amps, which was ten times the overcurrent device's coil rating. This device provided a time delay, usually measured in a few cycles, which was normally used for coordination purposes. The long time delay overcurrent test, which tests the long time delay device, was performed at 300% of rating. This measures the time duration that an overcurrent of this value could remain on the breaker prior to tripping. It had a characteristic time delay measured in seconds to minutes and was normally used for overload protection.

Mechanical actuation of molded case and metal clad circuit breakers was performed by manually and electrically operating the breaker to insure a clear, free operation in both the opening and closing modes.

Molded case circuit breakers had the following specific methods applied to them. Rated current hold-in tests were performed at 100% and 135% of current rating. These tests checked that the circuit breakers were capable of carrying the rated loads without tripping for times up to several hours. An overcurrent test at 300% of rating was performed to check the overload protection of the circuit breaker. Instantaneous trip tests were performed at 75% and 125% of the instantaneous rating. The 75% point verified that the circuit breaker did not trip instantaneously, characterized by a typical trip time of greater than 0.1 seconds. At the 125% point, the instantaneous trip was verified when the trip time was less than 0.1 seconds.

Molded case circuit breakers were also tested for 600% overload. In the 600% overload, the breaker was closed on 600% of rated current. Also, a dielectric test was performed with 2200 VAC applied between poles, with the breaker open and closed and between poles and ground. This was performed to verify the integrity of the insulations and case, which may have been reduced due to aging or degradation.

Protective Relay Measurements

Protective relays were additionally tested for zero check, induction unit pick-up, time / current characteristic, target and seal-in and instantaneous trip unit pick-up. The zero check verified that the contacts close when the time dial was set at the zero position for the GE devices and when the time dial was slightly to the left of the zero position for the Westinghouse devices. Induction unit pick-up verified the current required for the induction contacts to operate. The time / current characteristic was verified by monitoring the time for contact closure when a test current was applied. The manufacturer's characteristic curves were compared to the resulting conditions. This verified that the induction disk's movement and rotation were proportional to the applied current. The target and seal-in functions were verified to demonstrate the current at which the target picks up, and that the target was sealed in. The seal-in function verified that the target unit did not drop out when the current was removed from the induction unit. The instantaneous trip unit pick-up verified that the instantaneous coil picks up at a specified value of current and that the target or flag operates properly.

Induction Unit Pickup

The induction unit pickup current was measured by applying a current source to the induction coil and monitoring the induction contacts for closure. The minimum current required to close the contacts was recorded as the induction unit pickup.

Time / Current Characteristic

The GE specimens have a "very inverse" time characteristic and the Westinghouse specimens have "definite" time characteristic. Timing of the induction unit closure was measured by placing a timer across the induction unit contacts, applying current to the induction coil and monitoring the time required to close the induction contacts. The time-current characteristics were measured at 300%, 400% and 500% of tap value current for the GE specimens and 300%, 500% and 1000% of tap value current for the Westinghouse specimens.

Target and Seal-In

The DC Target and Seal-In Unit (GE relays) and Indicating Contactor Switch Unit (Westinghouse relays) functions were verified by using a DC supply. The typical acceptance criteria was 75% of setting.

Instantaneous Trip Unit

The instantaneous trip unit functions were verified by using the 70 millisecond pulse mode of a Multi-Amp CB8160 Circuit Breaker Test Set. The acceptance criteria for instantaneous pick-up was ± 10%.

Electronic Relay

The electronic relay was additionally tested for its time / current characteristic. The time / current characteristic was verified by monitoring the time for contact closure when a test current was applied. The manufacturer's characteristic curves were compared to the resulting conditions.

The tests on aged devices provided data which was compared by age of device. This allowed assessment of the effectiveness of each method by age. It also provided information useful for service life prediction which was discussed later in Section 5.

2.2.3 Tests on Degraded Relays and Circuit Breakers

In the next series of tests, eleven of the specimens were purposely degraded and the ISM methods performed after each degradation. The purpose of these degraded conditions tests was to evaluate the effectiveness of the method to detect and / or predict the level of degradation. This also provided some quantifiable parameters of the extent of degradation. The degradations chosen for each relay and circuit breaker type were purposely severe, but for the most part, did not cause total loss of operability of the device. Thus, it was an attempt to simulate the worst state of deterioration or degradation prior to failure to operate. The degradations were chosen based on a review and evaluation of the failure mode and mechanisms reported in phase I, specified by the nuclear and non-nuclear utilities, manufacturers, and experiences of the research team.

The degradation conditions were Blocked Armature, Contact Damage, Contact to contact resistance, Dirt Accumulation, Increased coil resistance, High potential test, Loose connections, Low contact current, Overheated, Shorted coil turns and Lack of lubrication. At least one of each type of relay and circuit breaker was subjected to the degradation conditions. Only those degradation conditions which were deemed applicable to the type of device were performed on a particular type of device. Table 2-4 summarizes the degradation conditions by device type and the following paragraphs summarize each type of degradation.

The blocked armature degradation simulated loss of armature movement due to changing tolerances or damaged parts. The armature movement was restricted by adding an obstruction to its movement.

The contact damage degradation simulated the effects of typical contact damage such as corrosion and pitting of contact surfaces and a contact which will not move when the relay is operated. Separate contact sets were used to simulate these conditions. Contact damage on the auxiliary, control, and protective relays consisted of three types of contact damage to three independent contacts: soldering two contacts together, severe pitting and burnishing contacts by removing the contact surface. Two types of contact damage, soldering and pitting, were simulated on the timing relay. For the electronic relay, contact damage was accomplished by indenting one of the contact surfaces on the connecting plug.

The contact to contact resistance degradation simulated the effects of a low resistance short between adjacent contact sets.

The dirt accumulation degradation simulated the effects of dust and dirt accumulation. A mixture of a light weight non-conducting oil and fine dust particles and water were sprayed into the devices to simulate a condition of neglect and obvious lack of housekeeping.

The increased coil resistance degradation simulated the effects of a weakening coil conductor over time. Coil resistance was increased by placing a low resistance in series with the coil. The resistance values used were : 200 ohms for the GE auxiliary relay, 2 ohms for the Westinghouse Auxiliary relay, 20 ohms for the control relay, and 10 ohms for the timing relay.

The high potential degradation simulated the effects of application of high potential voltages. A voltage of 2200 VAC was applied to the devices for a period of 10 minutes.

The loose connections degradation simulated the effects of vibration and cycling to loosen critical connections. All screws, nuts, and bolts were loosened on the devices to the point where they were easily turned by hand. This was usually one-quarter to two full turns. The connections were then selectively tightened until critical connections were identified.

The low contact current degradation simulated the effects of lower than rated current loads on contacts which are rated for much higher duty. Failures of relays have been described in NRC information notice 88-98, when lower than rated currents were the normal operating load for certain types of relays, especially those with silver contacts. In order to simulate this condition, all contacts were loaded to 5-10 mA for 6 hours.

The overheated degradation simulated the effects of a device being overheated. Overheating has occurred from self heating in a device as well as due to its proximity to some other heat source such as a transformer or high wattage resistance. The devices were overheated externally in this simulation until obvious effects were visible such as melting or deformation.

The shorted coil turns degradation simulated the effects of adjacent coil turns being shorted together. This was accomplished by cutting into the coil and soldering the windings in the area of the cut.

The lack of lubrication degradation simulated the effects of dormancy on metal clad circuit breakers. The research team's experience has been that most causes of failure to operate properly have been caused by lubrication becoming hard, no lubrication

Table 2-4. Degradation Conditions on Relays and Circuit Breakers

Degradation Condition	Device Type AUX	CONT	ELEC	PROT	TMNG	MLDCS	MTLCD
Blocked Armature	Yes	Yes			Yes		
Contact Damage	Yes	Yes	Yes	Yes		Yes	
Contact to contact resistance					Yes		
Dirt Accumulation	Yes	Yes	Yes	Yes	Yes	Yes	
Increased coil resistance	Yes	Yes			Yes		
High potential test	Yes	Yes	Yes	Yes	Yes	Yes	
Loose connections	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Low contact current	Yes	Yes			Yes		
Overheated	Yes	Yes	Yes	Yes	Yes		Yes
Shorted coil turns	Yes	Yes			Yes		
Lack of lubrication							Yes

Legend:

AUX : Auxiliary Relay
CONT: Control Relay
ELEC: Electronic Relay
PROT: Protective Relay
TMNG : Timing Relay
MLDCS: Molded Case Circuit Breaker
MTLCD: Metal Clad Circuit Breaker

coating critical surfaces and the device not being operated for long periods of time, six months or greater. This degradation was simulated by removing the existing lubricant.

In both the tests on aged devices and the degradation conditions tests, the normal installation and orientation were simulated. For instance, some relays, such as the auxiliary relays, are normally mounted through the doors of panels and supported by bezels attached to the panel. The test specimens were mounted this way for these tests. The ISM methods were also performed with some additional variations in order to account for limitations and variations which would occur in actual plant conditions. An example of this was measuring temperatures with infrared instruments. Infrared pyrometers and infrared scanners were used and readings taken at angles normal to the device and at forty-five degree angles to determine the effectiveness and necessity for more than one view.

The common degraded conditions were contact damage, dirt accumulation, loose connections, overheated and high potential test.

The specimens were overheated using a heat gun until visible signs of damage, such as melting or discoloration had occurred. Loose connections were created inside the relays by loosening the stationary induction unit contact and the tap screw of each specimen to the point where the relay still operated. Each specimen was subjected to a high potential of 2200 VAC for a period of ten minutes.

Low contact current degradation was accomplished by applying a lower than rated current, approximately 5 milliamps for six hours to the contacts. The contact to contact resistance was accomplished by adding a low resistance, approximately 20 ohms, between two adjacent contacts. The armature was blocked by installing a restriction between the armature and the relay frame. Shorted coil turns were achieved by cutting into the coil and filling the hole with solder. Dirt accumulation was accomplished by removing the cover, applying a multi-purpose spray lubricant, coating the relay with fine dust particles and adding a light mist of water. The specimen was overheated using a heat gun until visible signs of damage, such as melting or discoloration had occurred. The increased coil resistance was accomplished by adding a low resistance, approximately 20 ohms in series with the coil. The loose connection damage was accomplished by losing the terminal connections from half to 2 full turns. The high potential degradation was accomplished by applying a high potential of 2200 VAC for 10 minutes.

Contact damage was accomplished by indenting one of the ten contact brushes located on the lower connecting plug. Loose connections were created by inserting the top connecting plug such that it was 7/32" from complete insertion and the lower connecting plug such that it was 3/32" from complete insertion. Also, connections on two terminals were loosened one half to two turns. The specimen was overheated from the outside of its case with the cover installed using a heat gun until visible signs of damage such as melting or discoloration had occurred. Dirt accumulation was accomplished by removing the cover, applying a multi-purpose spray lubricant, coating the relay with fine dust particles and adding a light mist of water. The specimen was subjected to a high potential of 2200 VAC for a period of ten minutes.

2.2.4 In-situ Efforts

The practicability of the effective methods was also evaluated in the in-situ efforts. The in-situ tests were performed at two operating nuclear plants. The plants were Duke Power Company's Catawba Nuclear Station and Niagara Mohawk Power Corporation's Nine Mile Point Unit 1 Nuclear Plant. The maintenance, engineering and operations staff at both facilities were extremely knowledgeable and helpful.

During the in-situ efforts, the research team performed the following:

- Witnessed plant maintenance personnel performing routine plant maintenance on relays and circuit breakers,
- Copies of procedures were obtained,
- Results of plant maintenance tests were reviewed,
- Engineering and maintenance personnel were interviewed,
- Non-intrusive ISM methods of infrared pyrometry, infrared scanning and vibration testing were demonstrated to the plant personnel.

The in-situ efforts provided valuable insight into the routine relay and circuit breaker inspections, surveillances and monitoring methods currently in use, identification of the practicability of methods which had proven effective in the age and degradation tests and was helpful in evaluating the cost / benefit of the methods.

3. EVALUATION OF TESTS ON AGED DEVICES

The ISM methods were performed on thirty-nine relays and circuit breakers, which were obtained from a variety of sources. NPAR contractors, Battelle-Pacific Northwest Laboratory and Brookhaven National Laboratory, provided specimens which they had obtained as part of other NPAR efforts. Nuclear and non-nuclear facilities and manufacturers were contacted and specimens were obtained from many sources including Champion Paper Mill and Huntsville Utilities. Additionally, the Electric Power Research Institute and NUMARC solicited the U.S. nuclear power plants in an effort to obtain specimens. The result was that specimens were obtained from several nuclear power plants such as Diablo Canyon, Peach Bottom and Shippingport.

The tests on aged devices allowed comparisons of the ISM methods based on age of the relays and circuit breakers tested. Correlations among methods were noted when applicable. The results of performing the ISM methods on each of the relays and circuit breakers are described below:

3.1 Protective Relays

Five protective relays were evaluated. Three of the specimens were General Electric, Model 12IAC53B101A which were 10, 13, and 24 years old. Two of the protective relays were Westinghouse, Model CO which were 30 years old.

The most significant findings on the protective relays were :

- o Oxidation was found on contact surfaces,
- o Discolorations and slight odor of overheating were noted on the Westinghouse devices,
- o Evidence that last calibration interval was in 1985 for the GE devices,
- o Differences of induction unit pickup current were significant and increased with age. This method was performed four years since the last calibration in 1985 and shows that a calibration interval of 4 years was not adequate to assure typical accuracy,
- o Significant variation in the time/ current characteristic was noted in the Westinghouse CO protective relay,

- o Results of instantaneous trip unit pick-up current were affected by the procedure and test equipment used.

- o Increased temperatures with age, observable with the cover off, were noted with infrared pyrometry, infrared scanning and the on-contact method.

The five specimens used were single phase, non-directional, time overcurrent devices. The basic operating mechanism of the devices consisted of a magnetic-core operating coil, an induction disk and a damping magnet which combined to produce a time versus current characteristic. Overcurrent relays are AC current sensing devices which are used for phase and ground overcurrent protection.

Nineteen ISM methods were evaluated on the protective relays. The methods included visual inspection, contact resistance, coil resistance, magnetic flux, insulation resistance, zero check, induction unit pick-up, time/current characteristics, target seal-in, instantaneous trip, infrared pyrometry, infrared scanning, on-contact temperature, current surge comparison, inrush current, operating current, vibration testing, acoustic testing and ion detection.

The following results were obtained for the protective relays in the condition in which they were received for this phase II effort.

Visual Inspection

A GE Type IAC53 and a Westinghouse Model CO protective relay are shown in Figure 3-1.

All three GE specimens had calibration tags which indicated that they were last calibrated on November 21, 1985. Calibration was due November, 1986. The 24 year relay was extremely clean and appeared to have seen little service.

The moving contacts of the seal-in and instantaneous unit were open and operated freely on all specimens. The instantaneous and seal-in contact surfaces of the 10 year and 24 year specimens were slightly worn. The metal surfaces on the connecting plug of all three specimens exhibited brown discoloration. The connecting plug of the 24 year specimen had three connections that were highly discolored with areas of brown and blue. The auxiliary brushes inside the case of all three specimens were discolored similarly to the connecting plug metal surfaces. The metal brushes on the connecting block underneath each of the relays were highly oxidized.

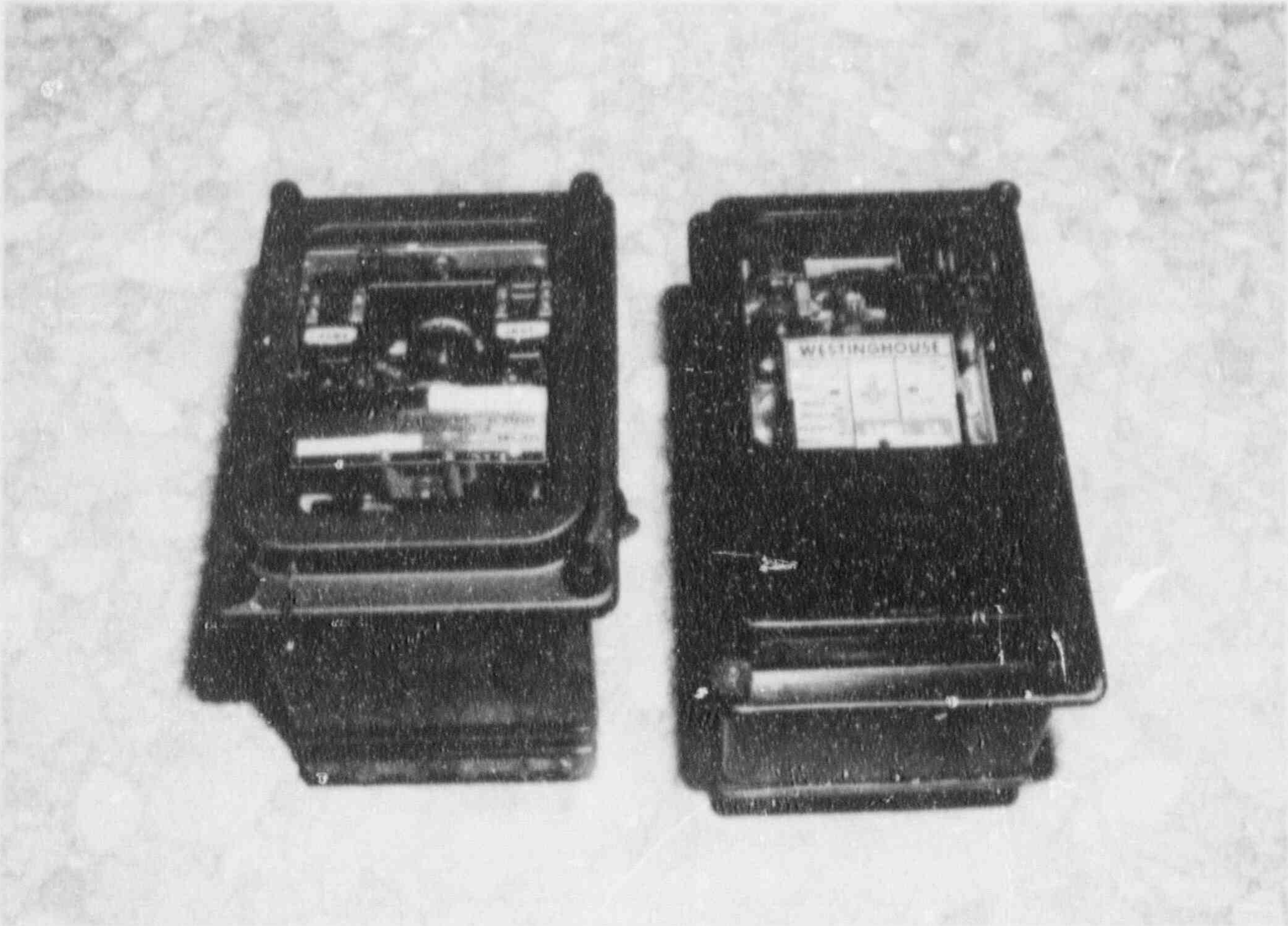


Figure 3-1. Protective Relays
General Electric 12IAC53B101A and
Westinghouse Model CO

The induction disk, instantaneous and seal-in contacts, which were silver or silver alloy, of the 10 year specimen showed no signs of unusual wear or contact pitting. However, the contacts on the 13 year and 24 year specimens were lightly discolored and worn. The insulation of tap lead wires 4 & 5 on the 10 year specimen were discolored and appeared overheated. The 13 year and 24 year specimens showed no evidence of tap or coil lead wire insulation damage. The coil and drag magnets of each specimen were checked for debris and metal filings. The coil magnet of the 10 year and 13 year specimens were lightly covered with metal filings. The coil magnet of the 24 year specimen was clean. The drag magnet on all three specimens had a slight amount of metal filings attached to its surface. Each specimen was checked for evidence of loose connections or parts and none were found.

The Westinghouse relays had three operational units: the Induction Disc Overcurrent Unit (CO), Indicating Contactor Switch Unit (ICS) and the Indicating Instantaneous Trip Unit (IIT). Due to the age of these relays, 30 years, manufacturer information, other than what was printed on the nameplate, including the time-current characteristics were not available.

The moving contacts of the ICS and IIT unit were open and operated freely on both specimens. The knife switches were dust and oil covered and discolored around the hinges on both specimens. The inside case of specimen 1 was covered with a light amount of dust and had a faint burnt odor. The induction disk, instantaneous and ICS contacts, which were silver or silver alloy, of both specimens showed signs of wear including oxidation and slight pitting. Wire insulation on the tap and coil leads showed signs of wear including discoloration and an odor of overheating on both specimens.

No foreign material or metal debris was observed on the drag magnet, coil magnet or induction disk. There were no signs of moisture present in the relay or other environmental contaminants.

Coil and Contact Resistance

Coil resistance is plotted against specimen age in Figure 3-2. The 10, 13 and 24 year specimens had resistances of 49.8, 65.5 and 50.9 milliohms respectively. The 13 year specimen had the highest resistance value and may have been a contributing factor to the significant percent change in induction unit pick-up, noted later. The Westinghouse specimens even though the same age, had resistance values of 293 and 145 milliohms respectively. These values differed significantly and as did the results obtained in the ISM methods: Induction Unit Pick-up, Time/Current Characteristic, and Magnetic Flux.

The significance of the coil resistance method was that a trend towards increased resistance is evident with age between the 10 and 13 year old GE specimens. The reason for the lower resistance in the 24 year specimen may have been its cleanliness which suggested that it had seen little service. The Westinghouse relays, being older showed very different coil resistance values, suggesting a trend towards increased variability with age.

The contact resistance was measured from the two stud terminals extending out from the back of the relay case with the time dial set to zero so that the induction disk contacts made contact. The studs were connected to several contact points by pressure, soldering, screw connections and the actual contact set. A total of seven series resistances were actually represented by the contact resistance measurement. Oxidation, loose connections, deterioration of wire insulation, contact pressure and contact damage significantly affect the values obtained. The contact resistance values of the GE 10, 13 and 24 year specimens were 592, 1000 and 1500 milliohms respectively.

The contact resistance exhibited a definite trend with age. Figure 3-3 shows this increase in resistance with age and the relative difference in magnitude when compared to the Westinghouse specimens. The high resistance values obtained with the 13 and 24 year specimens may have been due to the high oxidation observed on the stationary contacts and on the metal surfaces of the contact blocks. The higher contact resistance values obtained with the GE specimens may also have contributed to the slight variation shown in the time/current characteristic, discussed later. The Westinghouse specimens had resistance values of 551 and 649 milliohms respectively. The resistance difference, 98 milliohms, between the two specimens may have been a contributing factor to the large variance in timing ranges obtained in time/current characteristic.

<u>Magnetic Flux</u>

The magnetic flux of the GE specimens was measured at 300, 400 and 500% of tap setting current and the Westinghouse specimens were measured at 300, 500 and 1000% of tap setting current. The magnetic flux readings are shown in Figure 3-4. The magnetic field differences did not appear significant. No trend with age and no correlation with significant results of other ISM methods were found.

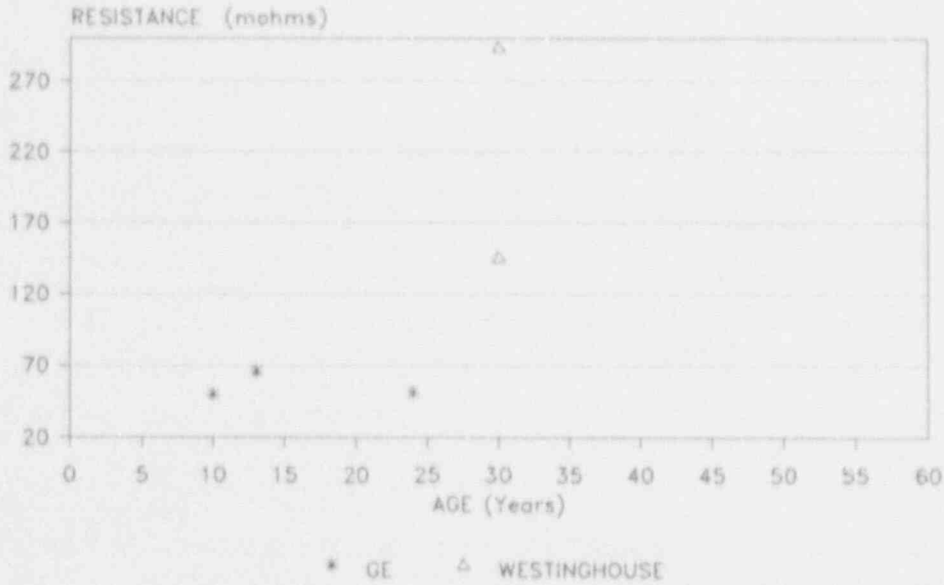


Figure 3-2. Coil Resistance
Comparison Protective Relays

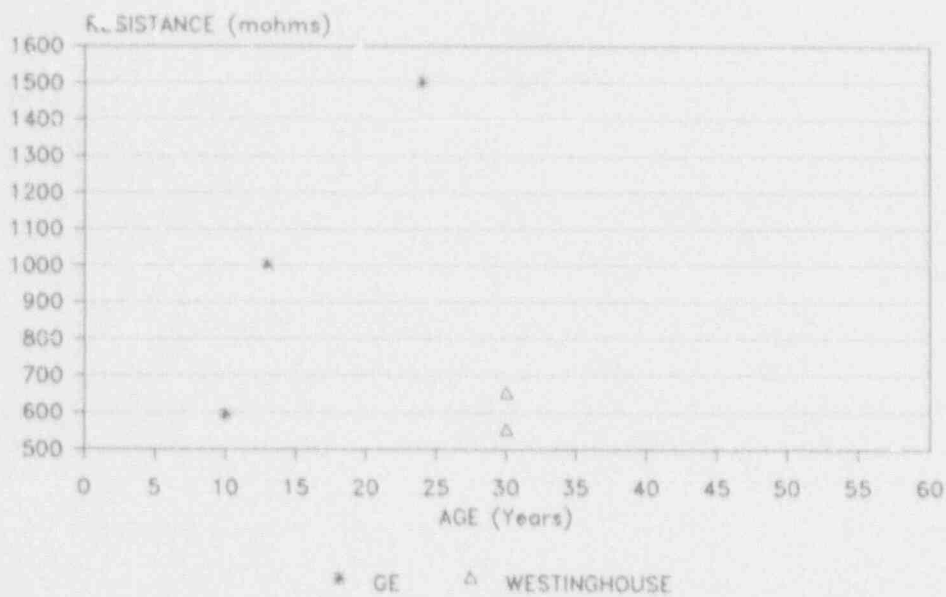


Figure 3-3. Contact Resistance
Comparison Protective Relays

Insulation Resistance

The GE specimens all had insulation resistance between 1.0 E10 ohms and 2.0 E10 ohms. The Westinghouse specimens had insulation resistance between 1.0 E8 and 1.0 E9 ohms. Insulation resistance differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Zero Check

The contacts of all GE specimens indicated continuity at the zero mark.

According to the manufacturer, Westinghouse protective relays should indicate continuity when the index mark is approximately 0.020 inches to the right of the "0" mark. Contacts of both specimens indicated continuity at approximately zero. The index mark was located slightly to the right of the zero mark. The offset was not easily discernible due to the location of the zero mark and time dial pointer.

The differences in zero check were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Induction Unit Pickup

Since the relays were from different manufactures and were not of the same model type, the percent change between the tap setting of the unit and the induction unit pickup current was calculated and compared along with the typical ± 5% acceptance criteria, Figure 3-5. Three of the five specimens were outside of the typical acceptance criteria. The 24 year GE and one of the 30 year Westinghouse specimens had a percent change of zero. The reason for the 24 year GE being in specification, when last calibrated at the same time as the other GE specimens, as noted on the calibration tag, may be due to its cleanliness and suggestion that it had seen little use.

Time / Current Characteristic

The time-current characteristics were measured at 300%, 400% and 500% of tap value current for the GE specimens and 300%, 500% and 1000% of tap value current for the Westinghouse specimens. Figure 3-6 shows the time range for contact closure for the range of values measured. The timing ranges for the GE 10 year, 13 year and 24 year were 3.2-1.4, 2.9-1.3 and 2.8-1.2 seconds respectively. The times obtained for the GE specimens were compared to the

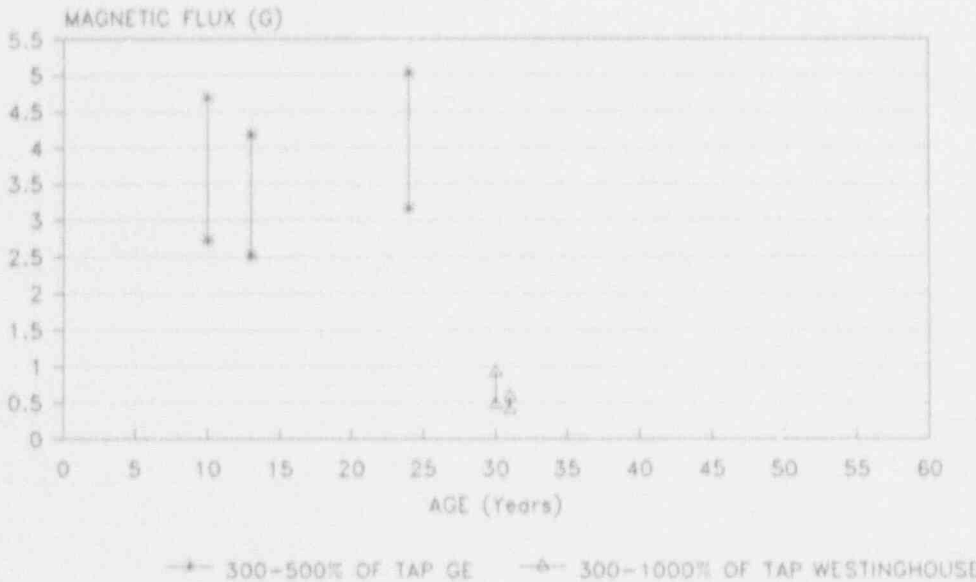


Figure 3-4. Magnetic Field
Comparison Protective Relays

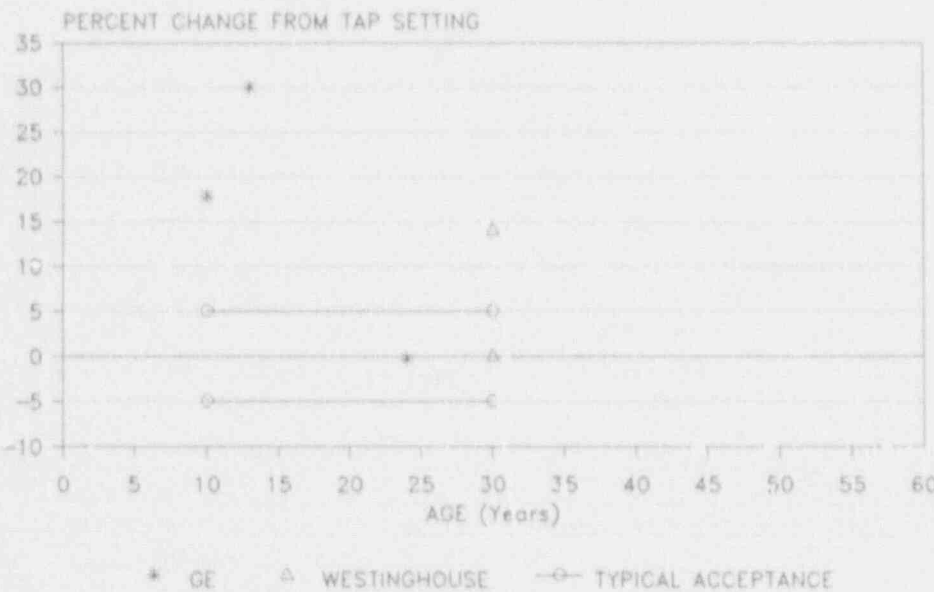


Figure 3-5. Induction Unit Pickup
Comparison Protective Relays

manufactures time/current characteristic curves and were all found to be within the specifications. Although the change was very slight, a 0.1 to 0.2 second decrease in time occurred with the increasing age of each device. This appears to be correlated with the increase in contact resistance with age, observed in the contact resistance method.

The timing ranges for the Westinghouse specimens were 27.8-43 and 17.5-24.7 seconds. No time/current characteristic curves were available for the Westinghouse specimens , however, the name plate states that the relay is a definite time 40 seconds which would indicate that the time should not vary much from 40 seconds. Time variation for the Westinghouse specimens was considerable and the ranges do not overlap. Typical timing acceptance is ± 5% and both were significantly out of this typical requirement. The specimen which was further from this acceptance criteria had the lower coil resistance, the higher contact resistance, the lesser variation in magnetic field and was out of typical acceptance for induction unit pick-up, thus suggesting a correlation among these methods.

Although the GE protective relays showed little change in the time/current characteristic, the Westinghouse specimens varied significantly. This method was performed four years since the last calibration in 1985 for the GE specimens and shows that a calibration interval of 4 years was adequate for the GE protective relay.

Target and Seal-In

The GE specimens had the tap set at 2.0 amps, which set the maximum pick-up value of current. The pick-up values, Figure 3-7, obtained for the GE 10 year, 13 year and 24 year specimens were within specification at 1.82, 1.87 and 1.7 amps respectively.

The Westinghouse specimens did not have a tap adjustment for the ICS unit. However, they did have a current rating on the nameplate of 1.0 amp for Indicating Coil and 2.0 amps for Contactor Switch. The pick-up values for the Westinghouse specimens were within typical acceptance at 1.01 and 0.92 amps.

The target flags for all five specimens functioned properly. The seal-in function was checked by applying the tap setting current (contactor switch current for the Westinghouse specimen) which was 2.0 amps for all five specimens, and removing the power from the induction unit. All five specimens remained sealed-in.

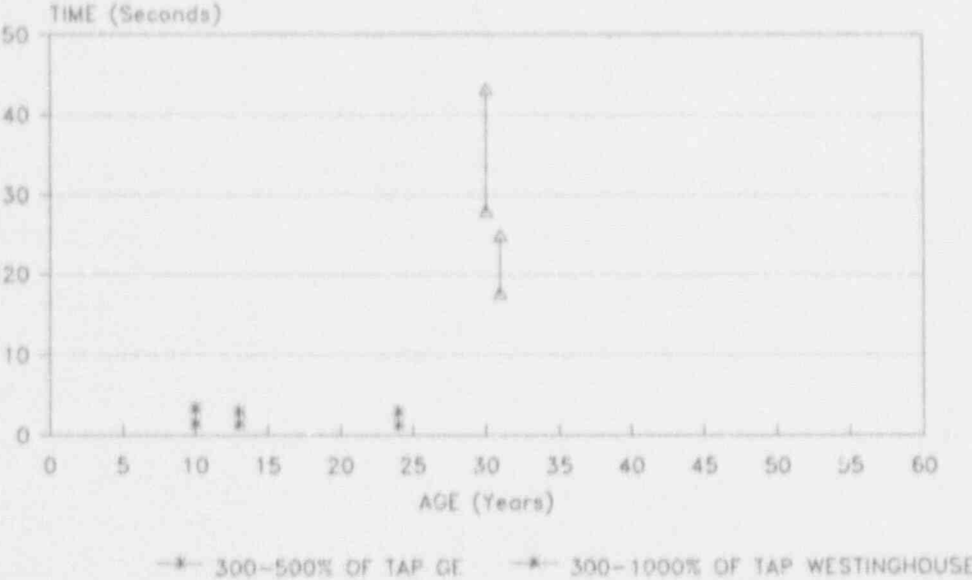


Figure 3-6. Induction Unit Timing
Comparison Protective Relays

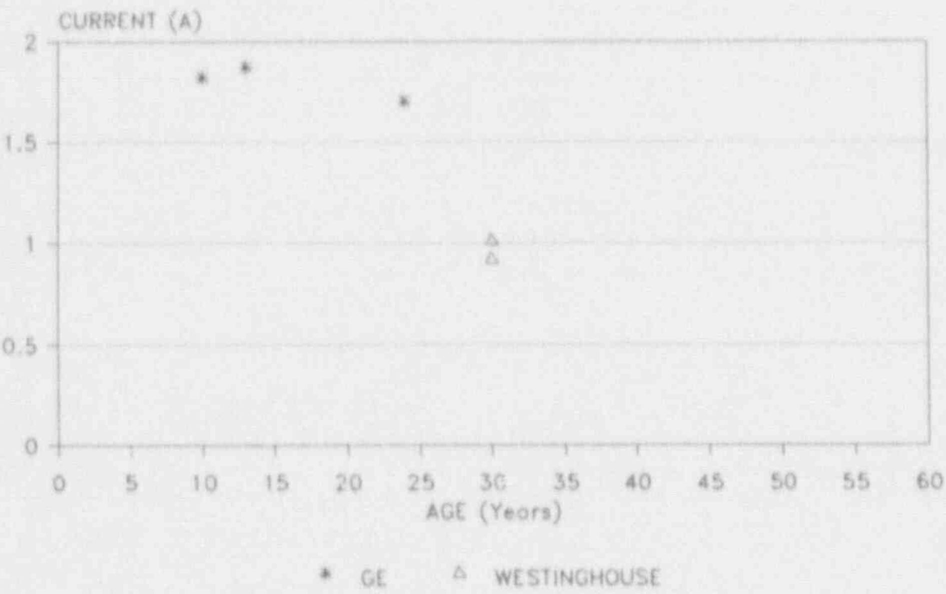


Figure 3-7. Target and Seal-In Pickup
Comparison Protective Relays

The differences in target and seal-in were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Instantaneous Trip Unit

The instantaneous pick-up setting of the GE specimens was 40 amperes and the induction unit tap setting was moved per the manufactures recommendation to the highest tap setting of 16. The instantaneous pick-up setting on the Westinghouse specimens was 80 amperes and the tap setting was moved to the highest setting of 6.

The instantaneous pickup current for the GE 10 year, 13 year and 24 year specimens were within specification at 40, 43 and 42 amps respectively, Figure 3-8, at the highest tap setting. The target indicators functioned properly on all three GE specimens.

The instantaneous pickup current for the GE 10 year specimen was tested at the lowest tap setting with the same test equipment. It was out of specification at 92 amps. It was then tested with a Multi-Amp, SR-51-4 Protective Relay Test Set. The specimen picked-up at 36 amps and 3.5 volts, while at the lowest tap setting.

It was concluded that the anomaly was the result of increased impedance of the relay when set at the lowest tap setting and inadequate voltage being supplied because of the voltage limiting characteristics of the test equipment. Thus the impedance of the GE instantaneous unit circuit at the lowest tap setting was too high to be driven by the test equipment.

The instantaneous pick-up for the Westinghouse specimens were within specification at 80 and 82 amps. The indicating target flag did not function for either specimen. The target flag coils were in series with the instantaneous unit through a series of connections in the relay. The target flag coil was isolated and verified to be operational when disconnected from the remainder of the circuit. This indicated that the impedance of the Westinghouse instantaneous unit circuit and target coil was too high to be driven by the test equipment.

The instantaneous trip unit pick up current method was significant. For both manufacturers, the results of the method were effected by the procedure and test equipment used. Increased irpedances in both devices were correlated with increased coil and contact resistances, which had been shown to be correlated with age.

Infrared Pyrometry

The maximum temperature measured is shown in Figure 3-9 for the GE specimens. This figure compares the temperatures obtained for the front view with cover on and cover off and the back view. Little change is noted from the back view and the front view with the cover on. The cover off view shows an increase of temperature with age. The lower temperatures on the 24 year specimen may be a result of its cleanliness and apparent little service.

Infrared pyrometry showed a significant trend to increased temperatures with age, observable with the cover off and slight trends observable with the cover on and on the back view.

Infrared Scanning

The temperatures exhibited an increasing trend with age, Figure 3-10. The 13 year and 24 year specimens were significantly hotter than the 10 year specimen as noted in the cover off view.

Infrared scanning showed the same trends as infrared pyrometry.

On-contact Temperature

An increasing temperature trend, with age, was also observed in this method for front views, Figure 3-11.

Current Surge Comparison

The GE 10 and 13 year specimens had similar waveforms measured with the test set as shown in Figure 3-12, with the combined signature pattern leading the master and small ringing at the tops of the waveform. The ringing of the 13 year specimen, Figure 3-13, was observed to be slightly larger than the 10 year specimen. The 24 year specimen differed significantly from the other two, Figure 3-14, with the signature pattern ringing very close to that of the current transformer (large ringing on the tops of the waveforms).

The Westinghouse specimens had waveforms which only varied slightly with the current transformer which indicated that the inductance of both specimens was approximately the same.

The variations in waveforms between the GE specimens was most likely caused by changes in the magnetic circuit of each specimen which may be due to aging of the coil insulation, but could be due to differences in the manufacturing process. The current surge comparison on protective relays may indicate a trend with age.

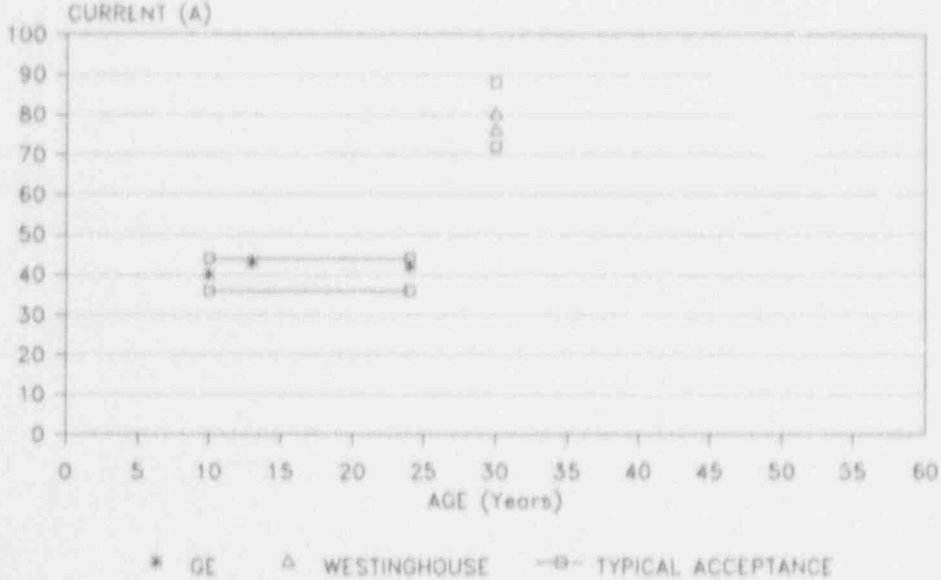


Figure 3-8. Instantaneous Unit Pickup
Comparison Protective Relays

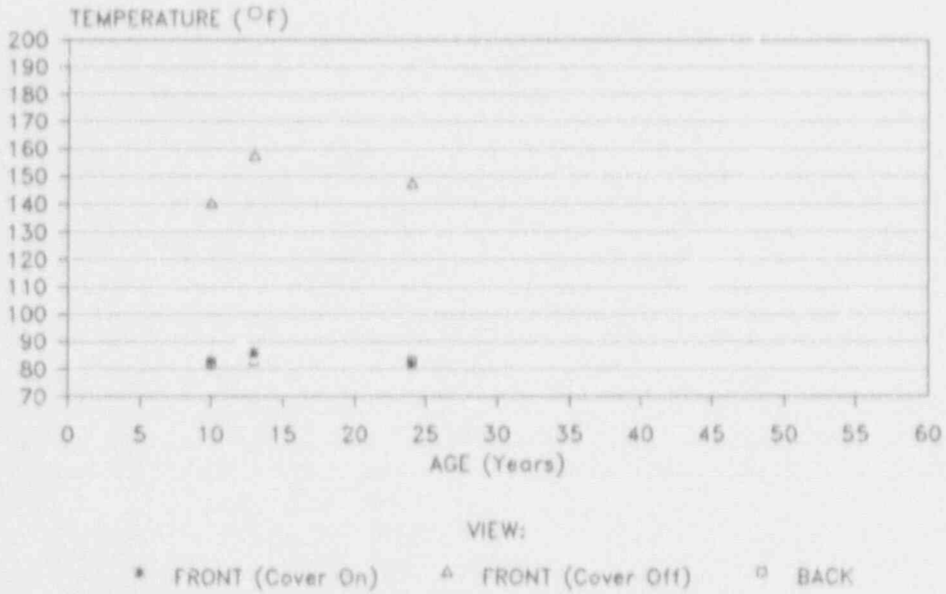


Figure 3-9. Infrared Pyrometry
Comparison Protective Relay GE IAC

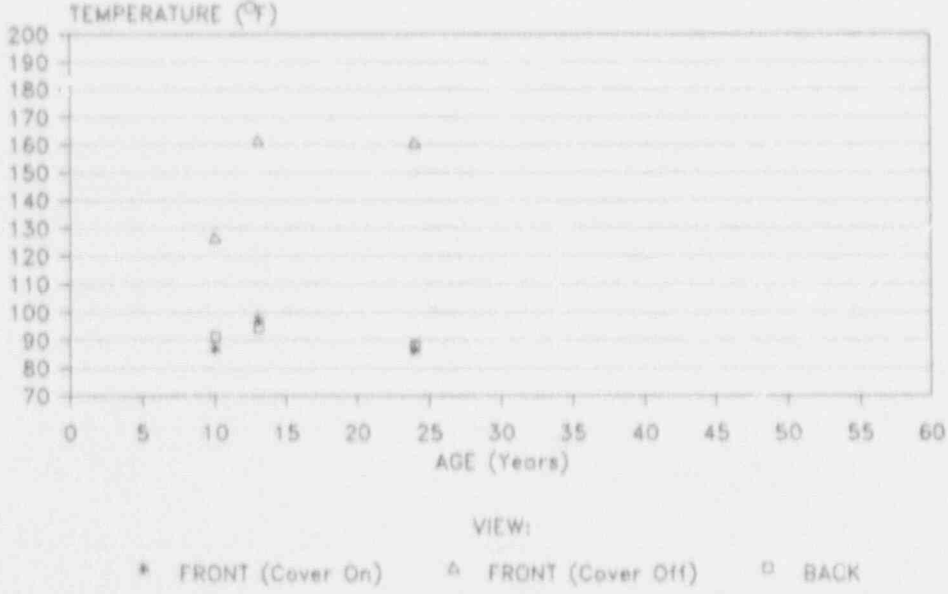


Figure 3-10. Infrared Scanning
Comparison Protective Relay GE IAC

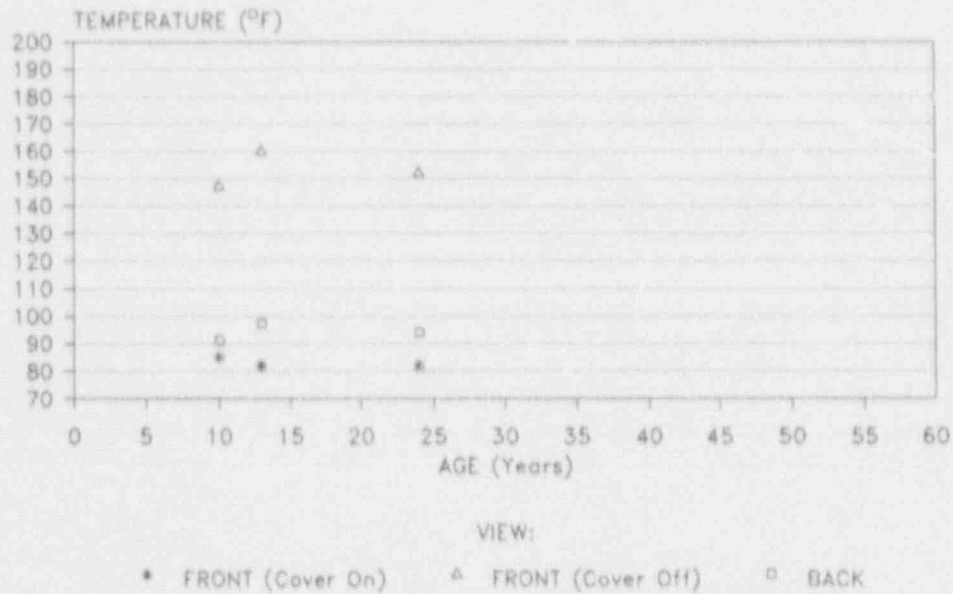


Figure 3-11. On-Contact Temperature
Comparison Protective Relay GE IAC

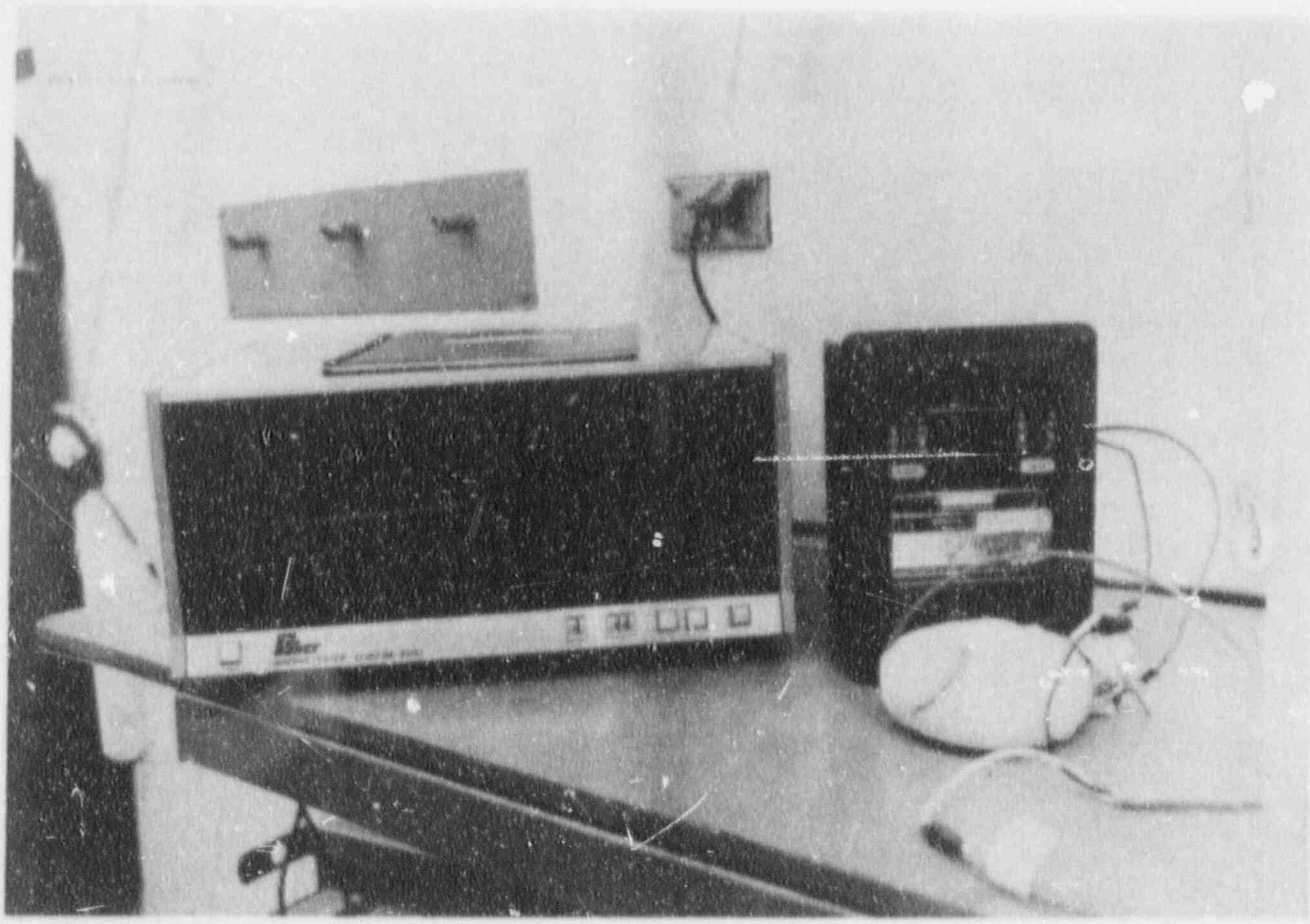


Figure 3-12. Baker DW-8505 Advanced Impulse Winding Tester Measuring Current Surge on GE IAC Protective Relay

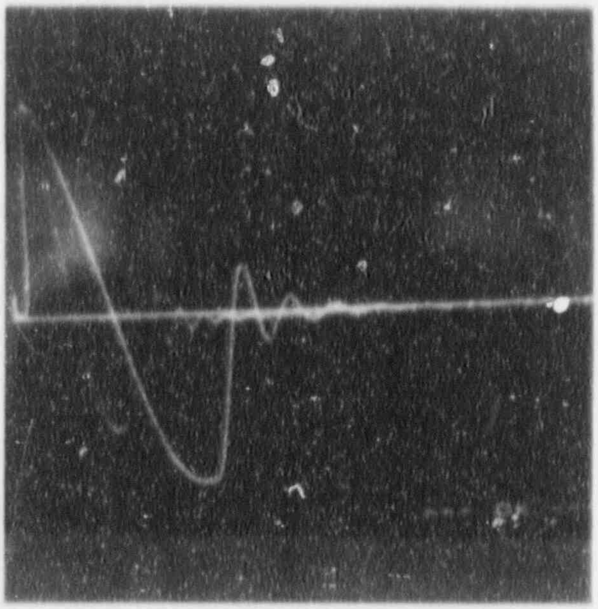


Figure 3-13. Current Surge Comparison on GE 13-year-old Protective Relay

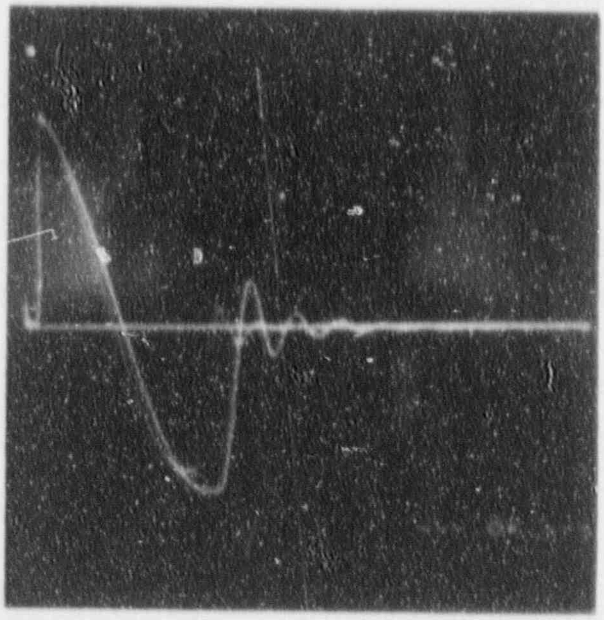


Figure 3-14. Current Surge Comparison on GE 24-year-old Protective Relay

Inrush and Operating Current

In order to compare the Westinghouse and General Electric relays, the ratio of operating current divided by the inrush current was calculated and compared. The current ratios were all close to 1 indicating very little deviation between inrush and operating current.

The differences in inrush and operating current were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Vibration Testing and Acoustic Testing

Vibration signatures were obtained during the timing tests and inrush current tests. The GE relays were characterized by very low level signatures. The signatures were repeatable and differences were noted among the different aged specimens. However, the low levels of the signatures makes interpretation of the differences difficult.

The vibration signatures on the Westinghouse relays were different from the GE signatures and almost ten times higher in magnitude. The Westinghouse vibration signatures were characterized by a sharp peak at approximately 360 Hz, but there was no significant difference in the two 30 year old specimens.

The acoustic signatures were repeatable and minor differences noted.

Vibration and acoustic signatures of aged specimens were different. The significance of these differences, considering the low levels of the signatures was indeterminate.

Ion detection

The detector only alarmed once. This happened when an overcurrent was inadvertently applied to one of the sample relays. A cloud of smoke formed on the inside of the relay case and shortly after, the smoke alarm located on the inside top of the enclosure alarmed. Both overheated relay insulation and test leads were evident.

The lack of ion detector alarm indicates that no concentrated ionization particles were outgassed from the specimens due to age.

3.2 Control Relays

Seven control relays representing three manufacturers were evaluated. The three manufactures and styles of relays were common safety-related control relays. They were Klockner-Moeller DIL00Lb22, Struthers Dunn 219 and Westinghouse ARD4T, Figures 3-15 through 3-17.

The most significant findings on the control relays were :

- o Some increase in contact resistance was noted with age on the SD219 relays, however this did not seem to effect operation except for an initially open circuit indication on one contact,
- o Pick-up voltage increased after energization on five out of seven relays, which is significant because the pick-up voltage on the oldest relay is approaching the acceptance criteria after energization,
- o Infrared Pyrometry showed a poor connection which was $30^{\circ}F$ hotter on one DIL relay, this connection showed up as a problem since the pyrometry tests were performed with the relay operating at rated current conditions and did not show up in the contact resistance tests, which are run at significantly less current,
- o Infrared scanning showed the maximum temperature to be slightly hotter than pyrometry in six out of seven relays, probably due to its ability to better define the hottest spot,
- o The maximum temperature for the DIL relays, from On-contact measurements was approximately $60^{\circ}F$ higher than the scanner, because the hottest spots were accessible for the On-contact probe,
- o The maximum temperature for the ARD4T relays, from On-contact measurements was approximately $20^{\circ}F$ less than the scanner, because the hottest spots were located at the encapsulated coil, for which there was no specific location point for the On-contact probe,
- o Current Surge comparison was shown to be difficult for the ARD4T relays because of their high resistance and high impedance,

Sixteen ISM techniques were evaluated on the control relays. They were visual inspection, contact resistance, coil resistance,

Figure 3-15. Klockner-Moeller
DIL002Lb22 Control Relay

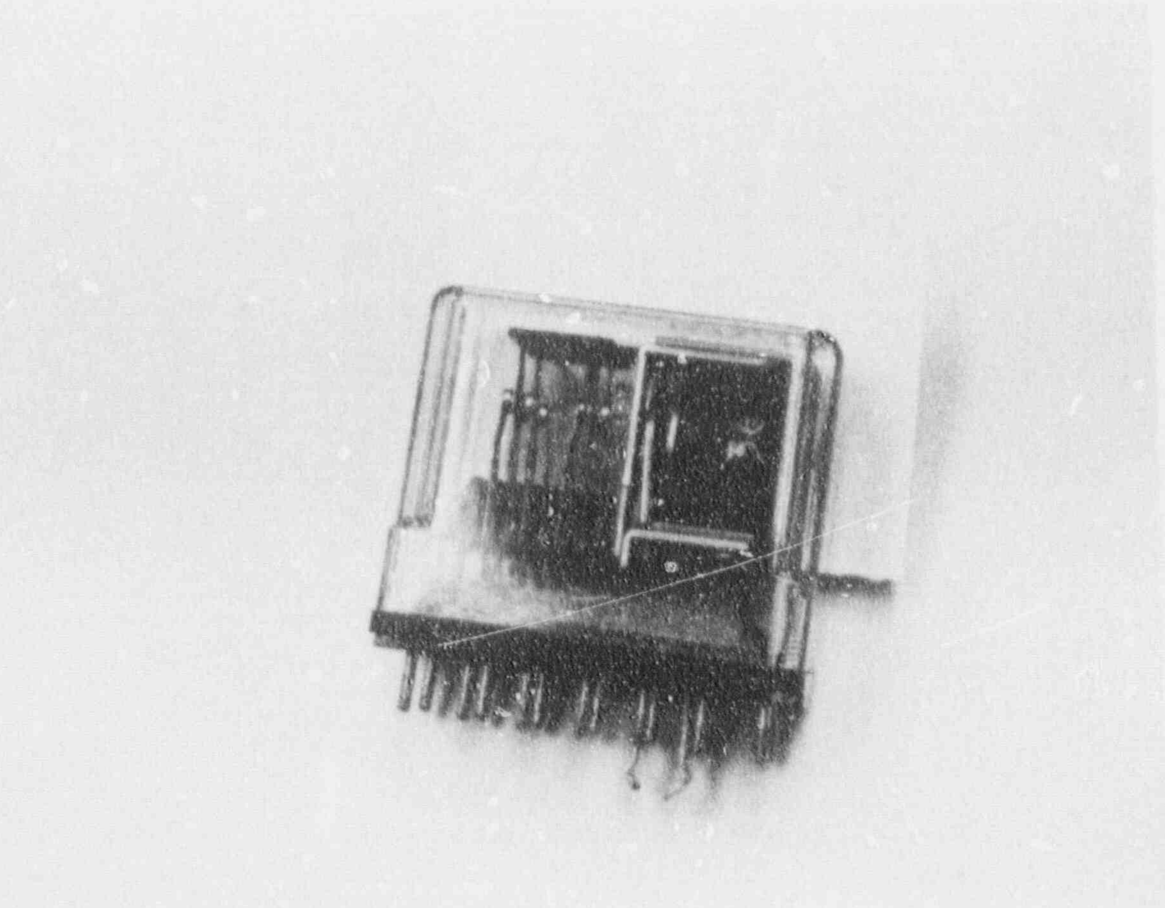


Figure 3-16. Struthers-Dunn
219 Control Relay

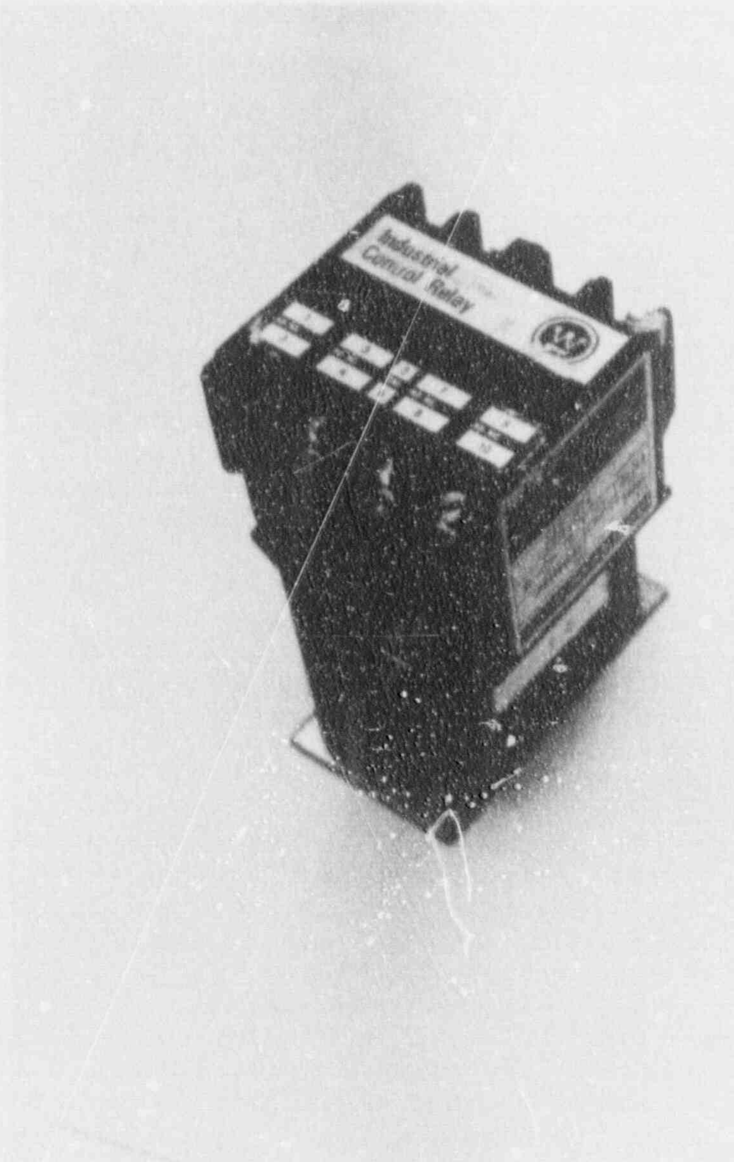


Figure 3-17. Westinghouse
ARD4T Control Relay

magnetic flux, insulation resistance, pick-up voltage, drop out voltage, inrush current, holding current, infrared pyrometry, infrared scanning, on-contact temperature, current surge comparison, vibration testing, acoustic testing and ion detection.

The following results were obtained from the relays in the condition in which they were received for this Phase II effort.

Visual Inspection

The Klockner-Moeller DIL00Lb22 control relays had no cover and the contacts and coil were easily accessible for close inspection. The Klockner-Moeller control relay had four contact sets, two N.O. and two N.C. which were rated to carry 20 amps continuously at 600VAC / 250VDC. The coil was rated for 120 VAC / 60Hz. Both specimens were approximately six years old and did not appear to have been in service. No problems were visible on either one. The contacts on both specimens showed no sign of pitting or unusual wear and neither specimen exhibited any sign of armature binding. The coil and coil lead wires showed no insulation damage and no unusual smell.

The Struthers Dunn control relay was covered by a polycarbonate cover that was connected to the relay with screws. This made close inspection of the contacts and internal parts difficult. It was inspected with the cover on. The Struthers Dunn 219 specimens contained 8 individual contact sets, 4 pairs of "FORM C" gold-plated contacts, 4PDT. The contacts were rated for 30 amps make and 10 amps continuous current. These relays had 24 VDC coils with a manufacturer's stated nominal cold resistance of 250 ohms. There were three Struthers Dunn control relays evaluated. They were reported to be 2, 12 and 12 years old, respectively. The contacts of the Struthers Dunn 219 were in good condition. None had contact pitting or wear. The history of the 12 year specimens were that both had seen significant heat in testing prior to the Phase II research. The copper fingers, on which the contacts are fixed, were discolored on both the 12 year old specimens. The insulated wires on all specimens were in good condition. The armatures were in good condition except for one of the 12 year specimens, which had slight discoloration.

The Westinghouse ARD4T control relay had a 240 VDC rated coil with four sets of N.O. contacts which were rated at 10 amps continuous current at 600VAC. The two specimens were both approximately six years old and apparently had never been in service. The contacts and coil were not visible on this model. No problems were evident from the visual inspection.

The visual inspection on control relays showed that no obvious problems existed and all appeared to be in good condition.

Contact and coil resistance

The contact resistance was measured in the as received condition for each specimen and after testing the other ISM methods. The lowest to highest resistances measured for the contact sets of each relay were summarized in Figure 3-18 for the as received initial condition and in Figure 3-19 for the post test condition. The contact resistance of the SD219 relays increased with specimen age. The initial contact resistance of the two year old specimen ranged from a low on one contact set of 5.9 milliohms to a high on another contact set of 25.2 milliohms. Contact resistance for one 12 year old specimen ranged from a low on one contact set of 11 milliohms to an open circuit on another contact set. The open circuit was reduced to 15 milliohms after relay operation. The contact resistance of the other 12 year specimen ranged from a low on one contact set of 7.3 milliohms to a high of 71.3 milliohms.

With the exception of the initial open circuit, contact resistance in general varied more from contact to contact after testing. The trend still was increased resistance with age.

Coil resistance was measured on each control relay at four different times during the tests on aged devices. The four times were first, in the as received condition, at the start of the ISM methods; second, after the relay had been energized for 2 hours; third, after the coil had been allowed to cool to ambient after ISM methods of pick-up, drop out, inrush and holding current; fourth, after the relay had been energized for 2 hours. Each time the coil resistance was measured, it was monitored for one minute and the resistance recorded at five seconds intervals.

The coil resistance for each of the control relays remained stable during all measurements, Figure 3-20.

Contact resistance was found to have increased with age on the SD219 and to have varied more after testing and did not cause problems exhibited in any of the other ISM methods. Coil resistance did not exhibit a trend with age.

Magnetic Flux

The control relay specimens were measured at 80%, 100%, and 110% of rated coil voltage and were plotted in Figure 3-21 showing the value at 80% voltage at the bottom and the value at 110% voltage at the top of each band. The magnetic flux on the Struthers-Dunn relays exhibited a slight increase with age and the

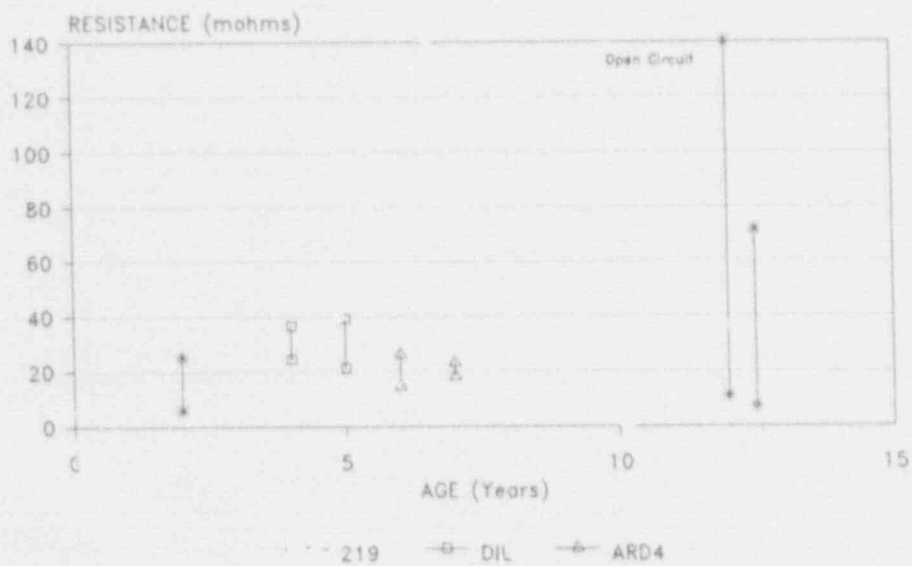


Figure 3-18. Initial Contact Resistance
Comparison Control Relays

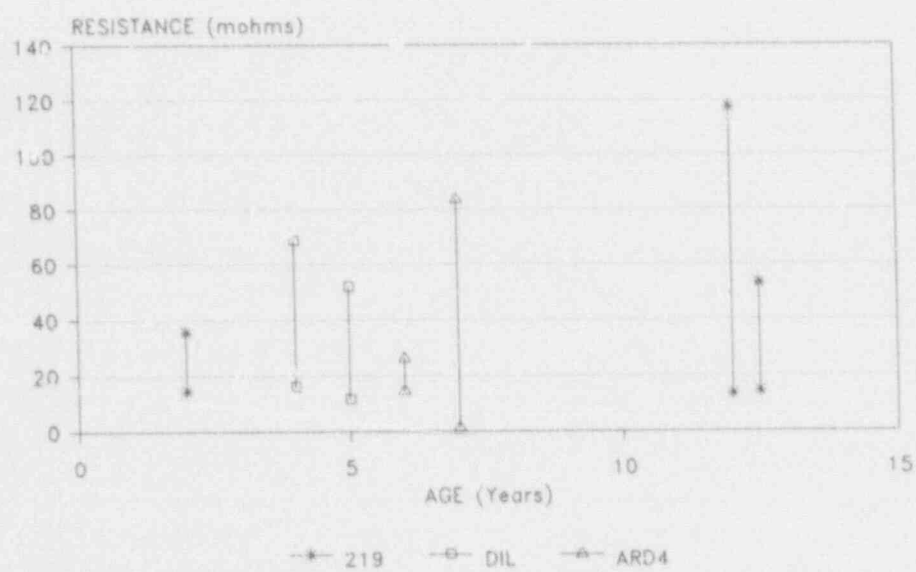


Figure 3-19. Post Test Contact
Resistance Comparison Control Relays

ARD4 relays differed from each other although they were the same age. The differences in magnetic flux were not significant and no correlation with significant results of other ISM methods were found.

Insulation Resistance

The insulation resistance values of adjacent contacts and contact to ground all exceeded 1 E8 ohms. Insulation resistance differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Pick-up and Drop-out Voltage

The pick-up voltages for the control relays were taken three times when the relay was at ambient conditions in the as received condition and three more times after it had been energized for 2 hours. Figures 3-22, 3-23 and 3-24 show the pick-up voltage for the SD219, DIL and ARD4T, respectively. All pick-up voltages were within the manufacturers acceptance criteria. Pick-up voltage increased after the relay was energized in five out of seven instances. One twelve year SD219 was most affected by the energization and was approaching the acceptance criteria. During pick-up, contact sequence was monitored to determine any deviation from simultaneous operation. There was no discernable contact closure pattern on pick-up for any of the control relays.

The drop out voltages were within specification for all control relays.

The significant result for pick-up voltage was the trend towards increased pick-up voltage requirements after energization with age.

For drop out voltage, no trend with age and no correlation with significant results of other ISM methods were found.

Inrush and Holding Current

Inrush current exceeds the holding current in the AC relays, DIL, and was the same in the DC relays. Inrush current differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Holding current differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found except for infrared pyrometry which showed that the relays were cooler when the holding current was less.

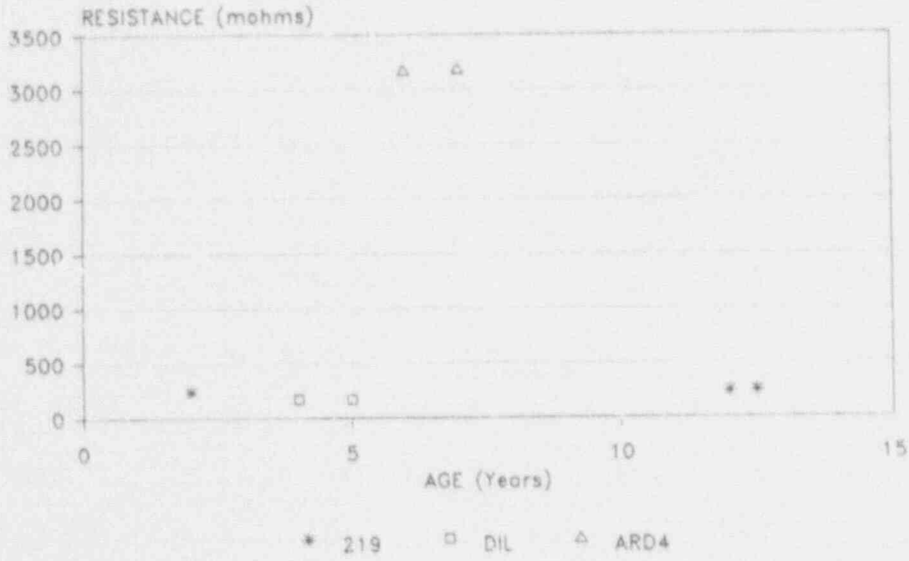


Figure 3-20. Coil Resistance
Comparison Control Relays

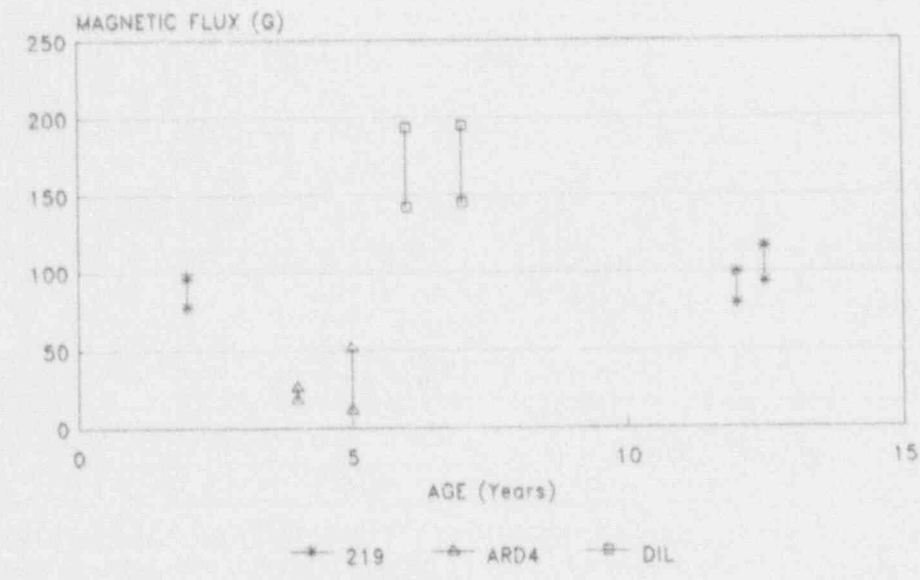


Figure 3-21. Magnetic Field
Comparison Control Relays

Infrared Pyrometry

The maximum temperature measured is shown in Figure 3-25. The one 12 year SD219 relay was cooler than the 2 and other 12 year specimens and correlates with the holding current which was less for this specimen. One of the Klockner-Moeller DIL relays was considerably hotter than the other by 30 ^{O}F. This style of control relay has no cover and connections and portions of the coil were visible in the three views (normal, right 45^{O} and left 45^{O}). On one specimen, the maximum temperature was 156^{O}F on the left side of the coil. The other specimen had a reading of 148^{O}F in this same area. The hottest spot of 186^{O}F was in the area of a connection on the right side of the relay.

Infrared pyrometry showed some significant differences among the devices. The decrease in temperature with age noted on the SD219 was correlated with the lower holding current in this device. The significant differences in the DIL specimens showed that infrared pyrometry detected a significant difference in a connection. Since infrared pyrometry was performed while the relay was operating, this connection problem showed up. It did not show up in contact resistance. Contact resistance uses a test lead at the connection and measures from the connection into the contact set of the relay at low current, 0.1 mA. Infrared pyrometry measured the relay with a simulated field connection while drawing rated current, 20 Amps.

Infrared Scanning

The maximum temperature measured is shown in Figure 3-26. Infrared scanning showed the same trends as infrared pyrometry. The maximum temperature was measured to be slightly hotter with scanning than pyrometry in 6 out of seven relays.

On-contact Temperature

The maximum temperature measured is shown in Figure 3-27. For the DIL relays, on-contact measured significantly hotter temperatures since the actual hottest spot was accessible with the on-contact probe for this model of relay. For the ARD4T relays, on-contact measured the hot spots at approximately 10^{O}F less than the pyrometer and approximately 20^{O}F less than the scanner. This was because the hottest spot was the side of the case where the coil was encapsulated and there was no specific access for the probe. On-contact measured on the SD219 relays was in general agreement with the pyrometer and scanner.

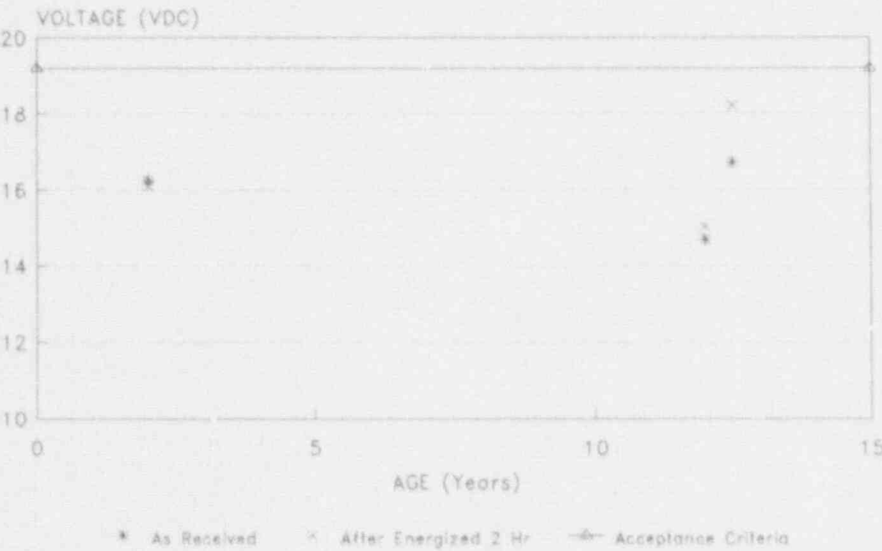


Figure 3-22. Pickup Voltage
Comparison Control Relay SD219

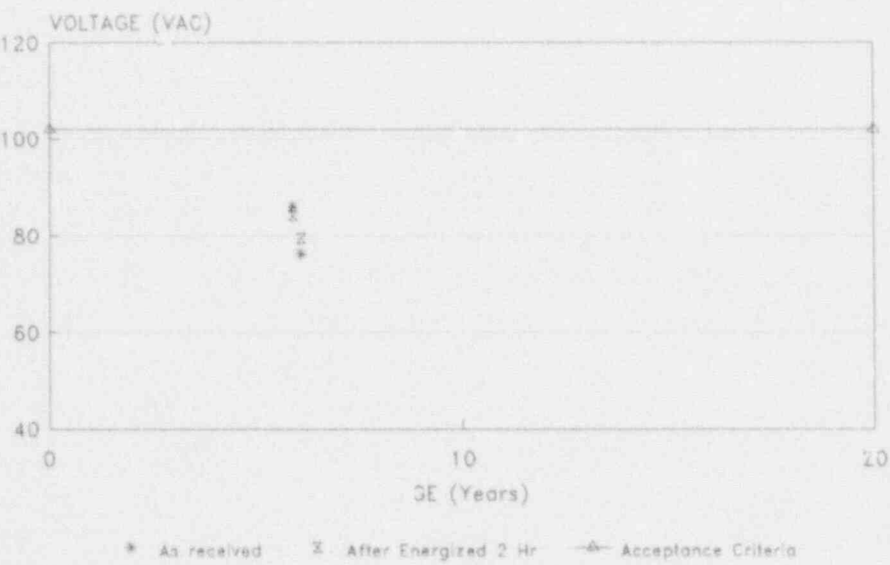


Figure 3-23. Pickup Voltage
Comparison Klockner-Moeller DIl

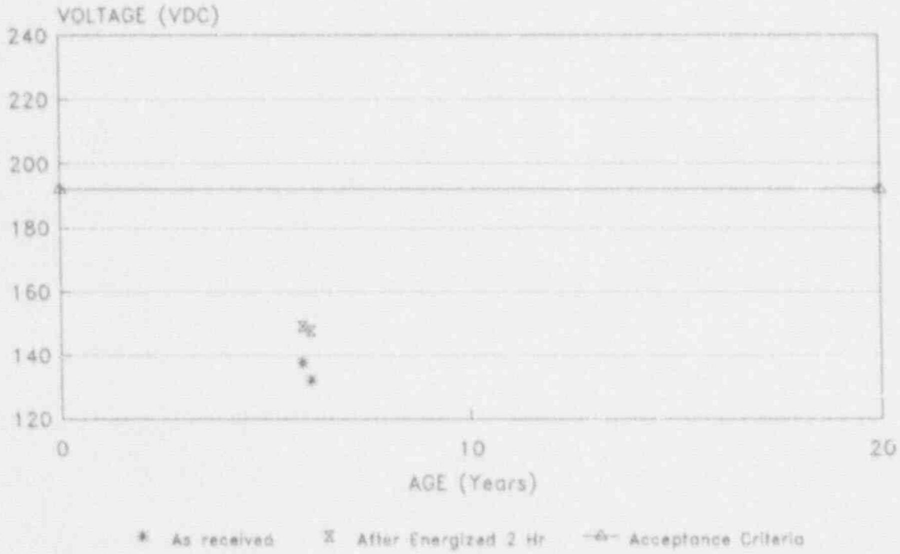


Figure 3-24. Pickup Voltage
Comparison Westinghouse ARD4T

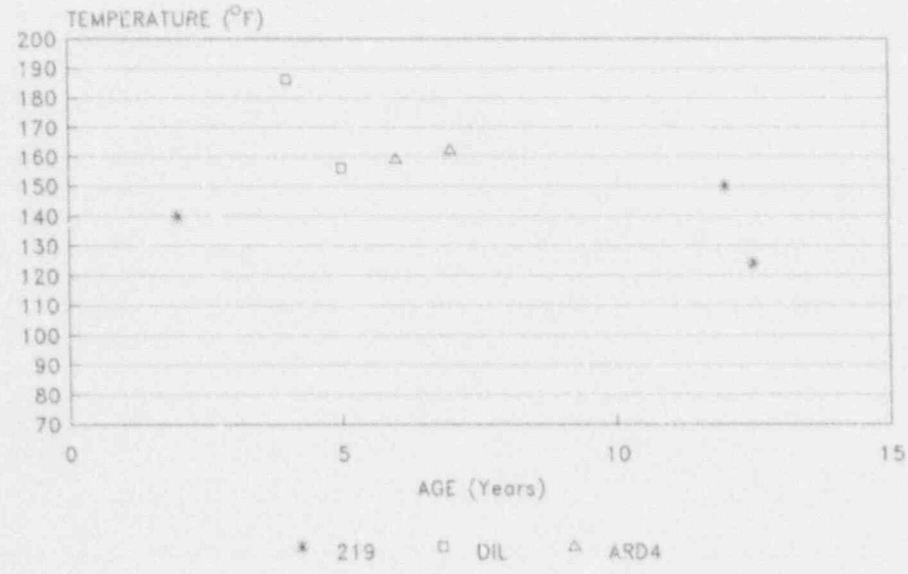


Figure 3-25. Infrared Pyrometry
Comparison Control Relays

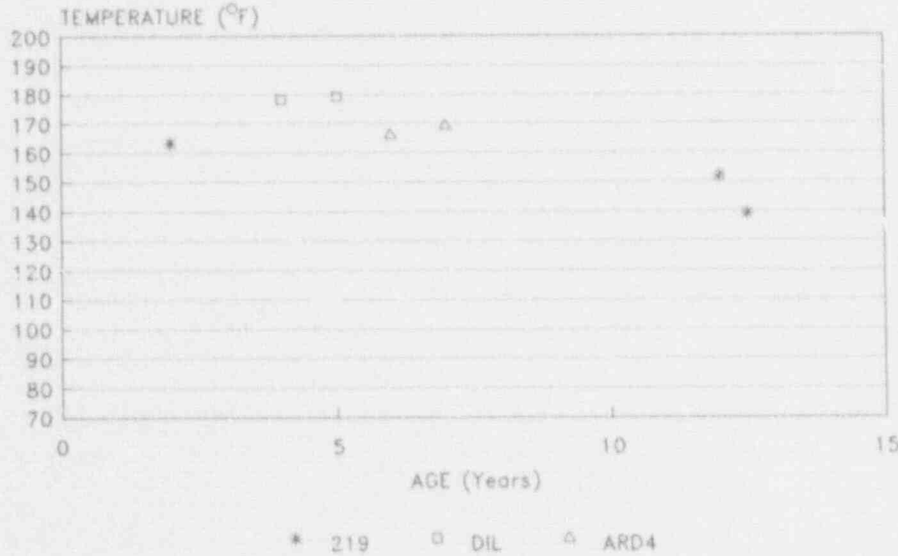


Figure 3-26. Infrared Scanning
Comparison Control Relays

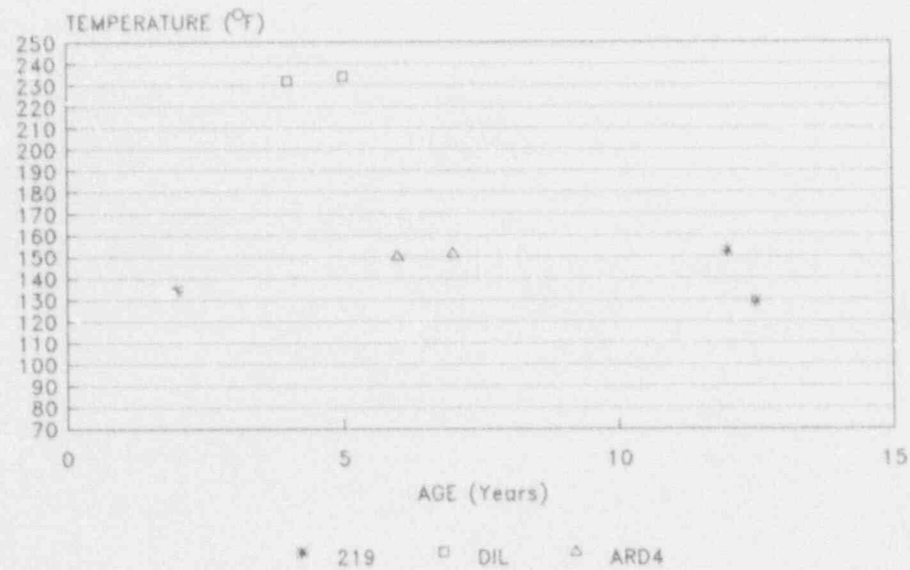


Figure 3-27. On-Contact Temperature
Comparison Control Relays

Current Surge Comparison

The ARD4T DIL showed no differences in Surge comparison waveforms. The SD219 relavs showed a difference between the 2 year specimen and the 12 year specimens. A small ringing was evident in the waveform for the 12 year specimens, but was not evidenced on the 2 year specimen.

Initial testing of the ARD4T by Baker Instrument Company showed that it was difficult to test because it had a high resistance and high impedance. Surge comparison waveforms on the coil were improved when the top and bottom core pieces were removed. This method would require disassembly on this type of control relay. They were tested in this effort in their assembled state.

The variations in waveforms between the 2 year and 12 year SD219 relays were most likely caused by changes in the magnetic circuit of each specimen which may be due to aging of the coil insulation and may indicate some turn to turn shorting, but could be due to differences in the manufacturing process. The current surge comparison on control relays may indicate a trend with age.

Vibration Testing and Acoustic Testing

Vibration signatures were obtained during the pick-up tests. The ARD4T relays were characterized by very low level signatures. The signatures were repeatable and differences were noted among the different aged specimens. The low levels of the signatures makes interpretation of the differences difficult.

The vibration signatures on the SD219 relays were different from the ARD4T signatures and almost five times higher in magnitude.

The DIL relays had unique vibration signatures with a characteristic peak at approximately 104 Hz.

The acoustic signatures were low and difficult to ascertain differences for the ARD4T. Both the SD219 and DIL relays had higher and more repeatable signatures.

Vibration and acoustic signatures of aged specimens were different. Since each relay operated properly, the significance of these differences was indeterminate, based solely on the tests of aged control relays.

Ion detection

An ionization smoke detector was mounted above each specimen during the above tests which required energization of the specimens. The detector never alarmed.

The lack of ion detector alarm indicates that no concentrated ionization particles were outgassed from the specimens due to age.

3.3 Electronic Relay

One electronic relay was evaluated in Phase II. It was a microprocessor based device which could monitor the magnitude of three-phase-and-neutral ac current providing time overcurrent and instantaneous overcurrent protection for 50 Hz or 60 Hz power systems. The specimen was a new Basler Electric BE1-51 electronic relay. Aged electronic relays were not available. Thus, no age comparisons were possible. The ISM methods were performed and were compared later to the degraded tests on the electronic relay.

Twelve ISM methods were evaluated on the electronic relay. The methods include visual inspection, contact resistance, coil resistance, overcurrent sensing pickup, time / current characteristic, instantaneous overcurrent, infrared pyrometry, infrared scanning, on-contact temperature, vibration testing, acoustic testing and ion detection.

The following results were obtained from the relay in the condition in which it was received from Basler Electric for this phase II effort:

Visual Inspection

The new electronic relay was found to be undamaged and in clean condition, Figure 3-28. The relay cover and two connecting plugs were removed and the relay slid out of the case for inspection. The connecting plugs were secure in their positions and required some effort to remove. The main and auxiliary brushes inside the case and metal surfaces of the connecting plugs and relay contact block showed no signs of discoloration or damage. The target indicator reset lever was manually operated and functioned properly. The relay power requirement was 125 VDC and had a current sensing input range of 0.75 to 4.0 amperes for phase and neutral sensing elements. The relay had 16 different switch selectable time overcurrent functions and a two thumbwheel switch time dial with 100 possible selections ranging from 00 to 99. The name plate was unscrewed and the selector position was noted to be set on zero which corresponds to the I^2T characteristic curve. The electronic components within the relay were mounted to PC boards including a mother board, analog board, logic board, power supply board and magnetics assembly.

All of the boards and electrical connections were new and in good condition. No loose parts, foreign materials or environmental contaminants were present inside of the relay.

Contact and Coil Resistance

The electronic relay contained three sets of contacts designated as time, instantaneous 1 (INST 1), and auxiliary. The electronic relay also contained four independent overcurrent sensing elements or coils designated as A, B, C and N. Each element was identified on the front of the relay with a circular target indicator which rotates 180° when the corresponding sensing output was energized by an overcurrent condition.

Overcurrent Sensing Pickup

The overcurrent sensing pickup current was measured by individually applying current to each sensing element and observing the pickup indicated by the illumination of the corresponding LED located on the front face of the relay. Once the LED was lit, the relay timed out with closure of the time and auxiliary contact. The current of each sensing element was 0.75 amps which was the tap setting. The acceptance criteria was ± 2% of the setting.

Time / Current Characteristic

The accuracy of the time overcurrent characteristic delay for the electronic relay was checked by applying current to the overcurrent sensing elements and monitoring the time required to close the time and corresponding auxiliary contact. The time / current characteristics were recorded at 300%, 500% and 700% of tap setting. The time for contact closure was compared to the time / current characteristic curve I^2T for each setting and were all within specification.

Instantaneous Overcurrent

The instantaneous overcurrent pickup of the electronic relay was measured using the 70 millisecond pulse mode of the Multi-Amp CB8160 Circuit Breaker Test Set. Current was applied in pulses to each sensing element and gradually increased until the INST 1 and corresponding sensing element indicated the instantaneous overcurrent pickup. The pick-up ranged from 47 to 51 amps for the four sensing elements.

Infrared Pyrometry and Scanning

The hottest spot using pyrometry was 88 ^{o}F, from the front 90^{o} view with the cover off. Ambient temperature was 78^{o}F. The hottest spot using scanning was 91 ^{o}F from the front left 45^{o} view with the cover off.

Figure 3-28. Basler BE-1 51 Electronic Relay

On-contact Temperature

The hottest spot was 86 ^{o}F from the front right 45^{o} view with the cover off and the 90^{o} back view.

Vibration and Acoustic Testing

Vibration and acoustic signatures were obtained only in the degraded tests on the electronic relay.

Ion Detection

An ionization smoke detector was mounted above the electronic relay specimen during above tests which required energization. It never alarmed during any of the tests.

3.4 Auxiliary Relays

Six auxiliary relays were evaluated in Phase II. Three of the specimens were DC armature type General Electric 12HFA51 which were new, 4, and 18 years old. Three of the auxiliary relays were AC armature type Westinghouse MG-6 one of which was new and two were 27 years old.

The most significant findings on the auxiliary relays were:

- o Pick-up voltage on two of the HFA relays, 4 year and 18 year specimens exceeds the acceptance criteria,
- o Pick-up voltage on the HFA relays increased after energization,
- o The maximum temperature, observed with the covers off, increased with age of the relay,
- o Infrared scanning located a hot spot on the back of an HFA relay which was 100^{o}F hotter than those obtained with pyrometry or on-contact measurements,
- o Significant vibration signature differences were noted among the HFA relays.

Sixteen ISM methods were evaluated on the auxiliary relays. The methods included visual inspection, contact resistance, coil resistance, magnetic flux, insulation resistance, pick-up voltage, drop out voltage, inrush current, holding current infrared pyrometry, infrared scanning, on-contact temperature, current surge comparison, vibration testing, acoustic testing and ion detection.

The following results were obtained for the auxiliary relays in the condition in which they were received for this phase II effort:

Visual Inspection

The basic operating mechanism of the devices consisted of an electromagnetic operating coil, a magnetic core, a control spring and a contact carrier attached to an armature assembly. Energization of the coil created a magnetic field at the coil end of the magnetic core, which overcame the control spring force and pulled in the armature assembly towards the coil pole of the magnetic core. Normally open moving contacts mounted to the armature assembly were drawn into the closed position by the armature movement.

The three GE 12HFA51 auxiliary relay specimens are show. in Figure 3-29. The two 27 year old Westinghouse MG-6 auxiliary relays are shown in Figure 3-30.

The GE auxiliary relays had a phenolic case and removable cover with a glass plate. The relay name plate and moving contacts were visible. The relays had six stationary contacts mounted to the phenolic case and six moving contacts mounted to the armature assembly. The new relay was clean and appeared to have seen little service. The moving contacts were open and operated freely on all specimens. The contact surfaces of the 4 year and 18 year specimens were slightly worn. The contact surfaces of the 18 year specimen were slightly discolored and small deposits of dust were present inside the relay case. Each specimen was checked for evidence of loose connections or parts and none were found. The new and 4 year HFA relay had Markel Flexite PVC tubing on each of the back connection terminals.

The coil bobbins were inspected. The new and 4 year HFA relay had tan Tefzel bobbins with "T" painted on the top. The 18 year HFA had a clear Lexan bobbin with a triangle painted on the top. The coil windings were visible through the clear Lexan and had no obvious problems. The 18 year HFA would have had a nylon bobbin(milky white) at the time of manufacture (per General Electric) and had obviously been changed with the Tefzel, which had been recommended by IE Bulletin 76-02. All bobbins were in good condition and had no noticeable damaged or broken parts, Figure 3-31.

The 27 year old Westinghouse MG-6 auxiliary relays had phenolic cases and removable covers with a glass plate. The relay name plate and moving contacts were visible. The new MG-6 relay had a phenolic back plate and no cover. The mounting for the new MG-6 was flush and the 27 year relays were door mounted. The relays had six stationary contacts, four located at the top and two located at the bottom, mounted to the phenolic case and six moving contacts mounted to the armature assembly. The new relay was clean and appeared to have never been in service. The moving contacts were open and operated freely on all specimens. Contact set 1 and 7 of the new relay was a "make-before-break" contact. The contact surfaces of the 27 year specimens were worn, oxidized and showed evidence of pitting. The top four contacts were more worn than the bottom two. Each specimen was checked for evidence of loose connections or parts and none were found. The date codes on the old MG-6 relays were "7/63" and "AUG 1963".

No foreign material or metal debris was observed on the relays. There were no signs of moisture present in the relay or other environmental contaminants.

Contact and Coil Resistance

The contact resistance for each contact set of the auxiliary relays was obtained by the Kelvin method at 1 Amp. The contact resistance was measured in the as received condition for each specimen and after testing the other ISM methods. The lowest to highest resistances measured for the contact sets of each relay were summarized in Figure 3-32 for the as received initial condition and in Figure 3-33 for the post test condition. The contact resistance of both HFA and MG-6 auxiliary relays increased with specimen age.

Coil resistance was measured on each auxiliary relay at four different times during the tests on aged devices. The four times were first, in the as received condition, at the start of the ISM methods; second, after the relay had been energized for 2 hours; third, after the coil had been allowed to cool to ambient after ISM methods of pick-up, drop out, inrush and holding current; fourth, after the relay had been energized for 2 hours. Each time the coil resistance was measured, it was monitored for one minute and the resistance recorded at five second intervals.

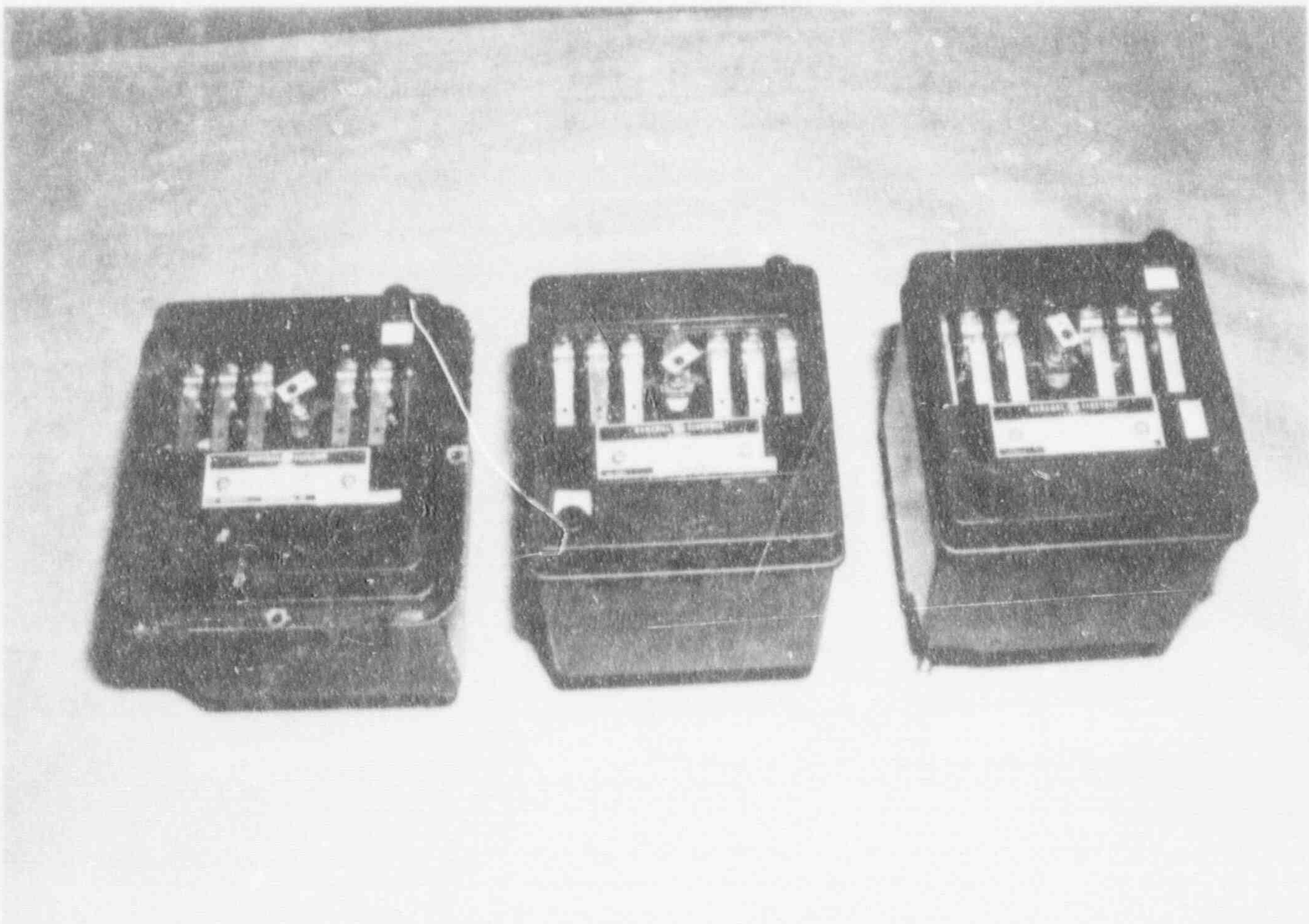


Figure 3-29. General Electric
12HFA51 Auxiliary Relays
(Left to Right, New, 4-year, 18 year)

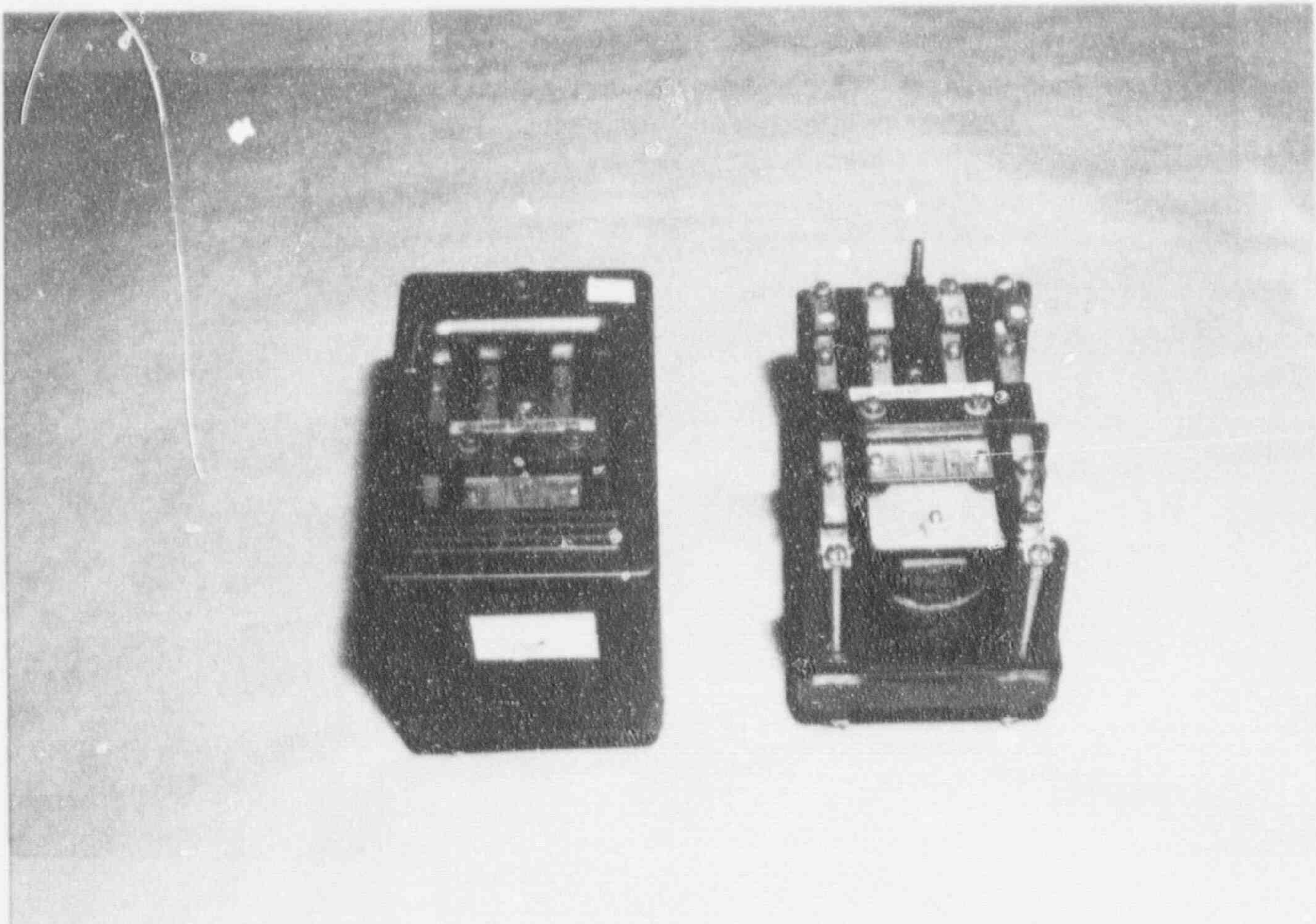


Figure 3-30. Westinghouse 27 Year Old
MG-6 Auxiliary Relays

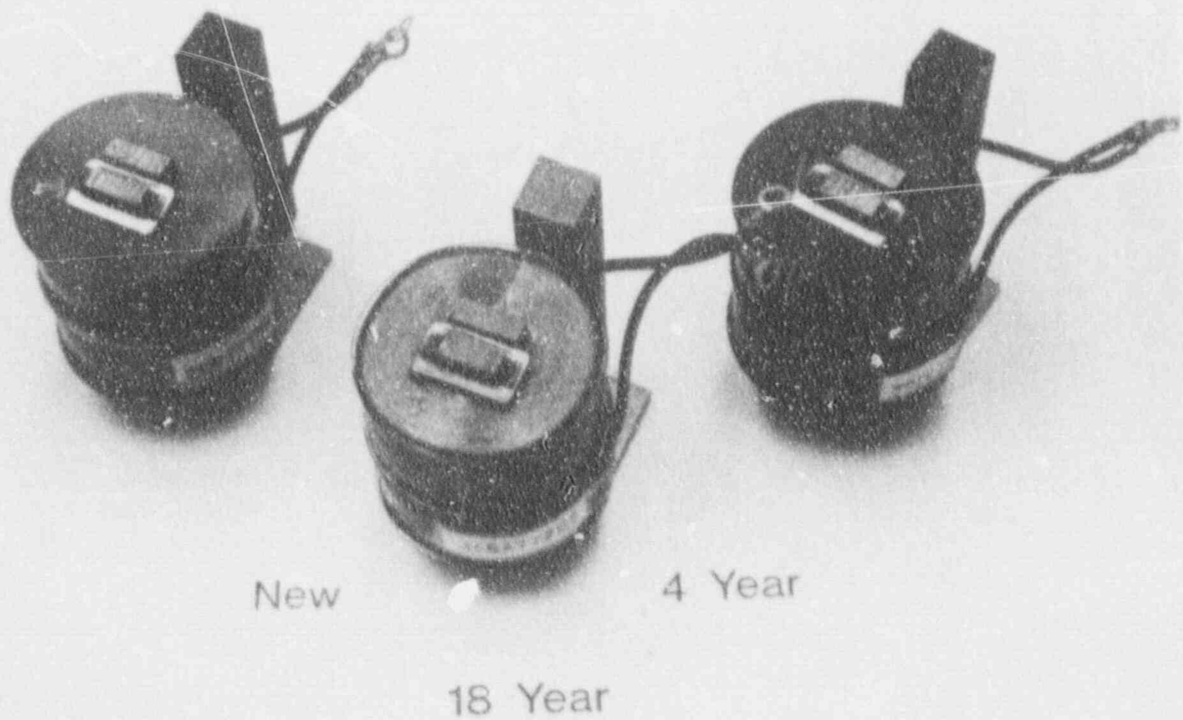


Figure 3-31. GE HFA Auxiliary Relay Coils

The coil resistance for each of the auxiliary relays remained stable during all measurements.

Contact resistance was found to have increased with age on the auxiliary relays, to have varied more after testing but did not cause problems exhibited in any of the other ISM methods. Coil resistance did not exhibit a trend with age.

Magnetic Flux

The magnetic flux of the relay specimens were measured at 80%, 100%, and 110% of rated coil voltage and were plotted in Figure 3-34 showing the value at 80% voltage at the bottom and the value at 110% voltage at the top of each band. Since the new Westinghouse MG-6 relay did not have a cover, the gaussmeter probe was closer to the coil. This resulted in higher magnetic flux values.

The differences in magnetic flux were not significant and no correlation with significant results of other ISM methods were found.

Insulation resistance

Insulation resistance values of adjacent contacts and contact to ground all exceeded 2.8 E8 ohms. Insulation resistance differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Pick-up and Drop out Voltage

The pick-up voltages for the auxiliary relays were taken three times when a relay was at ambient conditions in the as received condition and three more times after it had been energized for 2 hours, Figure 3-35. The pick-up voltage on the HFA relays increased with age. The acceptance criteria on the HFA relay was 75 Volts when cold and 100 volts when hot. The 18 year and the 4 year HFA exceeded the acceptance criteria in the as received condition. After energization for 2 hours, the pick-up voltage increased for all HFA relays. The pick-up voltage on the 18 year relay was 111 volts and exceeded the acceptance criteria.

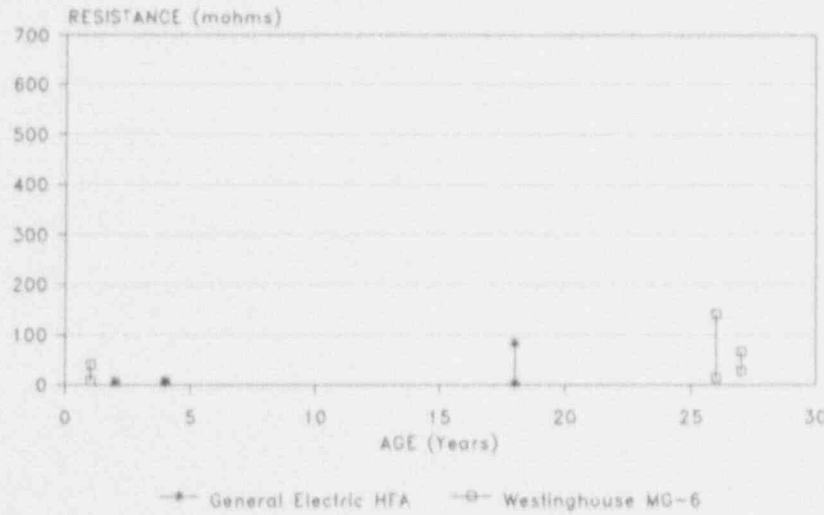


Figure 3-32. Initial Contact Resistance
Comparison Auxiliary Relays

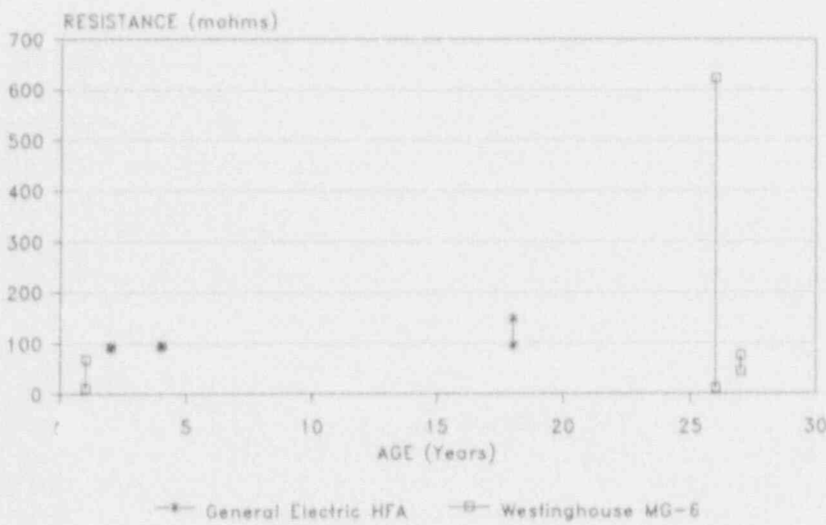


Figure 3-33. Post Test Contact
Resistance Comparison Auxiliary Relays

The MG-6 relays were within the manufacturers acceptance criteria, did not change after energization and did not exhibit a trend with age.

During pick-up voltage testing, contact sequence was monitored to determine any deviation from simultaneous operation. There was no discernable contact closure pattern on pick-up for any of the MG-6 or 27 year HFA relays, but contact set 1 and 7 was a "make-before-break" contact on the new HFA relay.

The drop out voltages were within specification for all auxiliary relays.

The significant result for pick-up voltage was the trend towards increased pick-up voltage requirements on the HFA with age and the increase in pick-up voltage requirements after energization. For drop out voltage, no trend with age and no correlation with significant results of other ISM methods were found.

Inrush and Holding Current

Inrush current exceeded the holding current in the AC relays, MG-6, and was the same in the DC relays, HFA. Differences in inrush and holding current for the MG-6 relays were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Infrared Pyrometry

The maximum temperatures measured for the HFA and MG-6 relays are shown, respectively, in Figures 3-36 and 3-37 for the front of the relay with the cover on, front with cover off and the back of the relay for those which were door mounted.

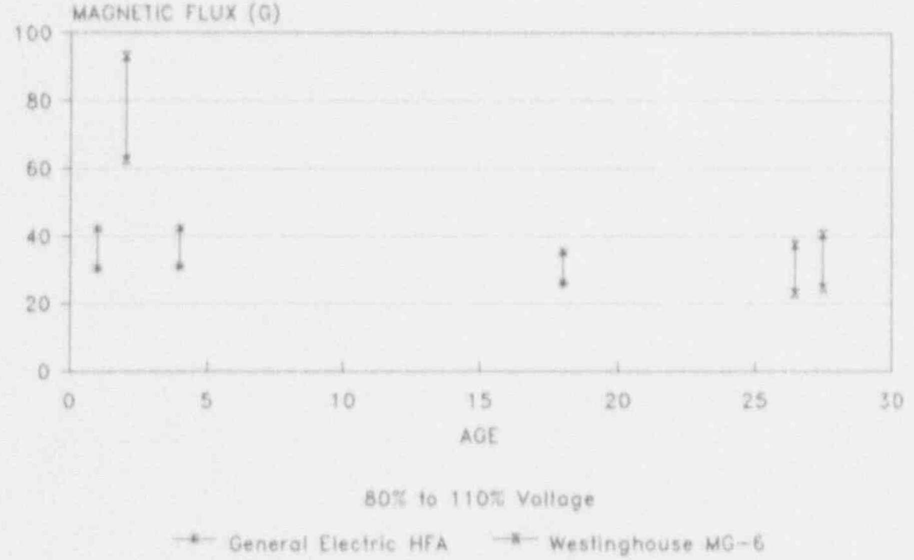


Figure 3-34. Magnetic Field
Comparison Auxiliary Relays

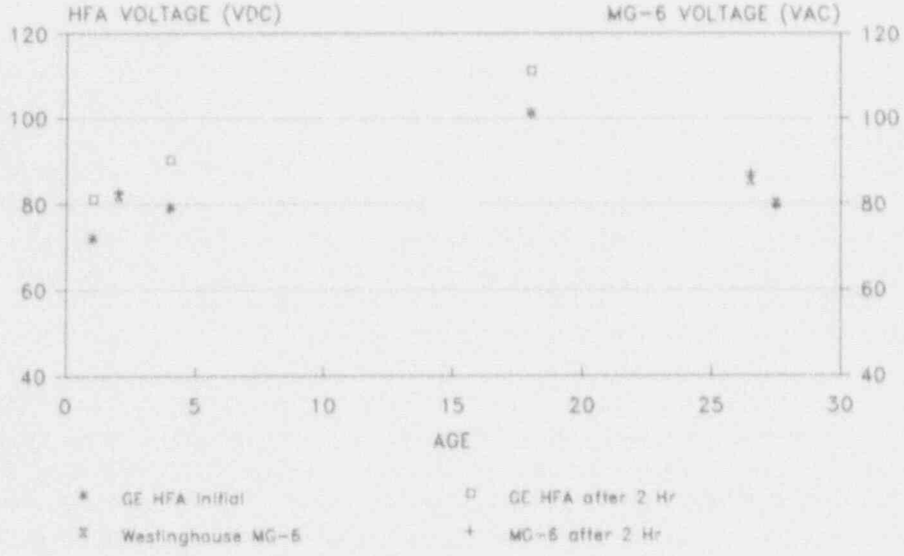


Figure 3-35. Pick-up Voltage
Comparison Auxiliary Relays

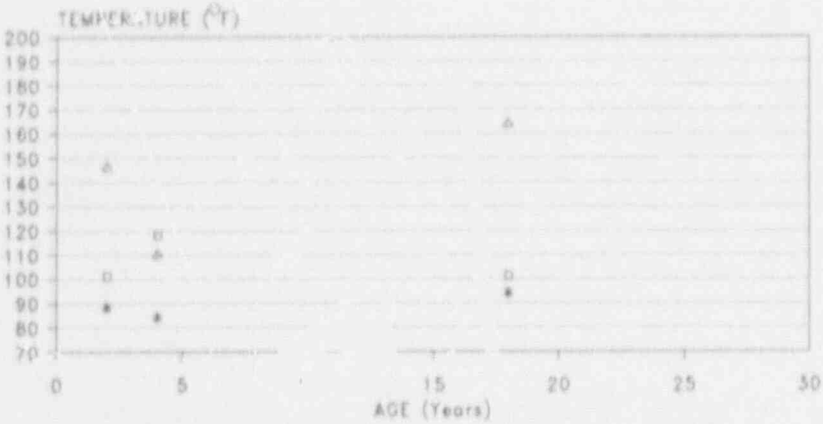
Infrared pyrometry showed some significant differences among the devices. The auxiliary relays exhibited a trend towards increased temperature with age which was observable when the cover was removed. For the 4 year HFA, the hottest spot, which was obtained by the scanner and on-contact temperature measurement from around the coil, was missed with the pyrometer. It was apparently overlooked since the pyrometer requires focusing a 0.25 inch spot on the specimen. Figure 3-36 shows the maximum temperature to be 110^{O}F, which should have been approximately 150^{O}F. Also, for the 18 year HFA relay, pyrometry and on-contact methods missed the hottest spot on the back of the relay, which was shown to be 100^{O}F hotter with the scanner.

Infrared Scanning

The maximum temperatures measured are shown in Figures 3-38 and 3-39 for the HFA and MG-6 relays, respectively. Infrared scanning showed the same trends as infrared pyrometry. The maximum temperature was measured to be slightly hotter with scanning than pyrometry in five out of six relays. The clear bobbin on the 18 year HFA coil made the magnetic wire visible and this coil exhibited a higher temperature of approximately 30^{O}F than the other coils. The scanner showed that the back of the 18 year HFA relay , opposite the coil, was 100^{O}F hotter than obtained with the pyrometer and on-contact methods.

On-contact Temperature

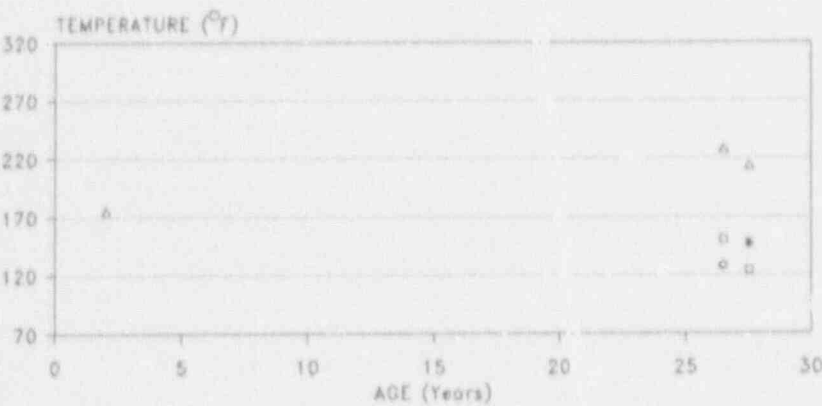
The maximum temperatures measured are shown in Figures 3-40 and 3-41 for the HFA and MG-6 relays, respectively. For the MG-6 relays, on-contact measured significantly hotter temperatures, with the cover off, since the actual hottest spot was accessible with the on-contact probe for this model of relay. For the HFA relays, on-contact measured the hot spots at approximately 10^{O}F less than the scanner and approximately the same as the pyrometer, with two exceptions. For the 18 year HFA, the on-contact measurement on the coil was 35^{O}F less than the scanner. The on-contact measurements were less because the hottest spots, the coil, was inaccessible by the probe. Also, for the 18 year HFA relay, pyrometry and on-contact missed the hottest spot on the back of the relay, which was shown to be 100^{O}F hotter with the scanner. The on-contact method



VIEW:

* FRONT (Cover On)   △ FRONT (Cover Off)   □ BACK

Figure 3-36. Infrared Pyrometry
Comparison Auxiliary Relay GE HFA



VIEW:

* FRONT (Cover On)   △ FRONT (Cover Off)   □ BACK

Figure 3-37. Infrared Pyrometry
Comparison Auxiliary Relay
Westinghouse MG-6

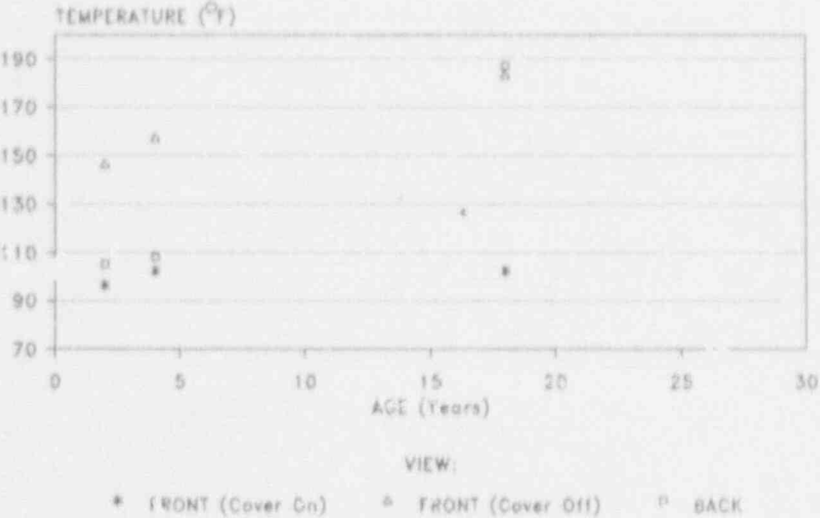


Figure 3-38. Infrared Scanning
Comparison Auxiliary Relay GE HFA

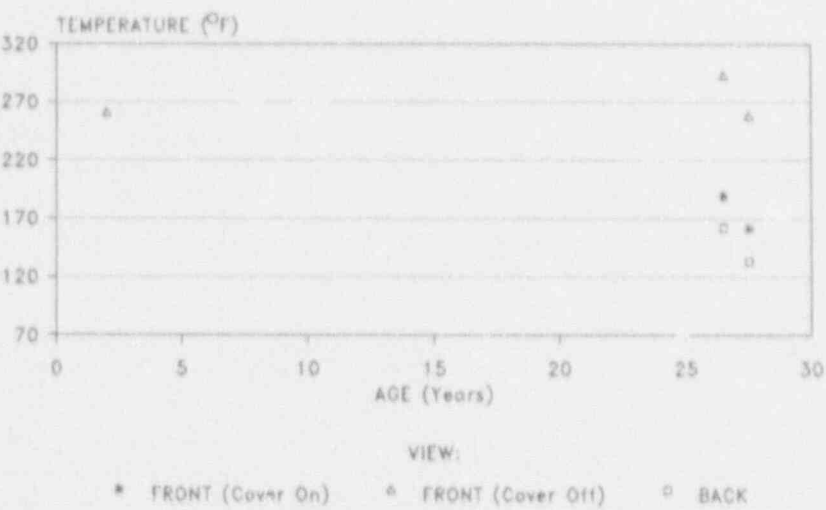


Figure 3-39. Infrared Scanning
Comparison Auxiliary Relay
Westinghouse MG-6

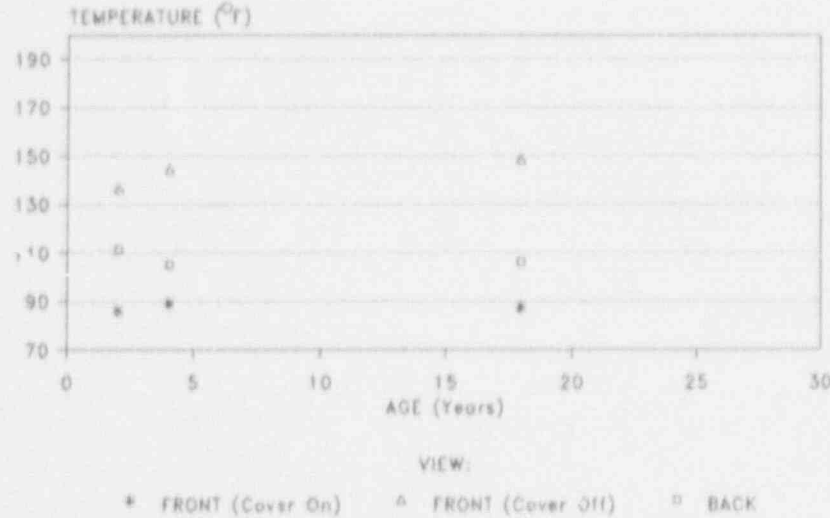


Figure 3-40. On-Contact Temperature
Comparison Auxiliary Relay GE HFA

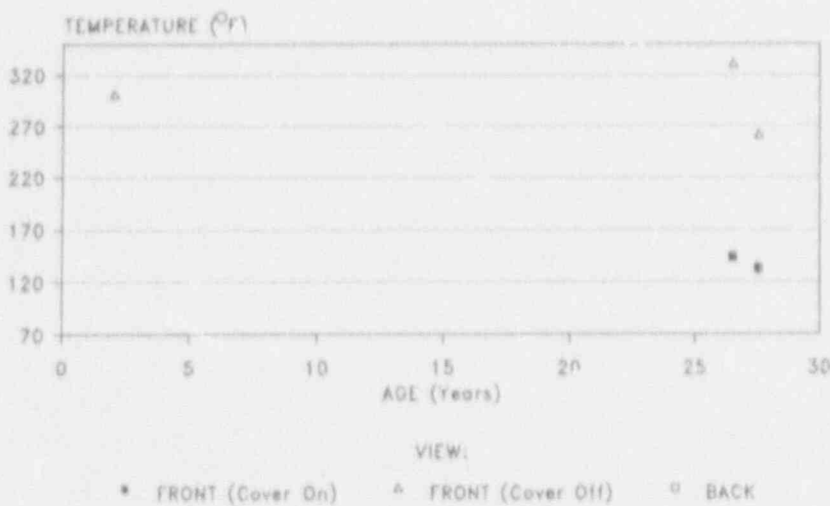


Figure 3-41. On Contact Temperature
Comparison Auxiliary Relay
Westinghouse MG-6

pinpoints a spot, therefore the location of the hottest spot was overlooked because it was on the case in a location not near the contacts, which were suspected to contain the hottest spot.

Current Surge Comparison

Significant differences were noted in the MG-6 relays. Ringing was noticeable on the two 27 year MG-6 relays, which may be due to aging of the coil insulation, but could be due to differences in the manufacturing process. The current surge comparison on auxiliary relays may indicate a trend with age.

Vibration Testing and Acoustic Testing

Vibration signatures were obtained during the pick-up tests. The vibration signatures were repeatable and differences noted among the different aged specimens for both the HFA and MG-6 auxiliary relays. The vibration signatures for the HFA relays are shown in Figure 3-42. Differences in the vibration signatures were mainly in the range from 636 Hz to 800 Hz although several additional peaks were noted on the 18 year HFA.

For the MG-6 relays, Figure 3-43 shows the differences among the three relay specimens. Changes were noted in the peaks at approximately 110 Hz, the addition of peaks at 1272, 1358 and 1800 Hz and loss of peak at approximately 1600 Hz in the 27 year specimens.

The acoustic signatures were similar but different for each of the HFA relays and the MG-6 relays. Significant differences in the 600 to 800 Hz range were noted on the HFA relay and in the 400 and 800 Hz range on the MG-6 relays.

Vibration and acoustic signatures of aged specimens were different. The differences suggest that aging may have been influencing the characteristics of the signatures.

Ion detection

An ionization smoke detector was mounted above each specimen during the above tests which required energization of the specimens. The detector never alarmed.

The lack of ion detector alarm indicates that no significant concentration of ionized particles had outgassed from the specimens due to age.

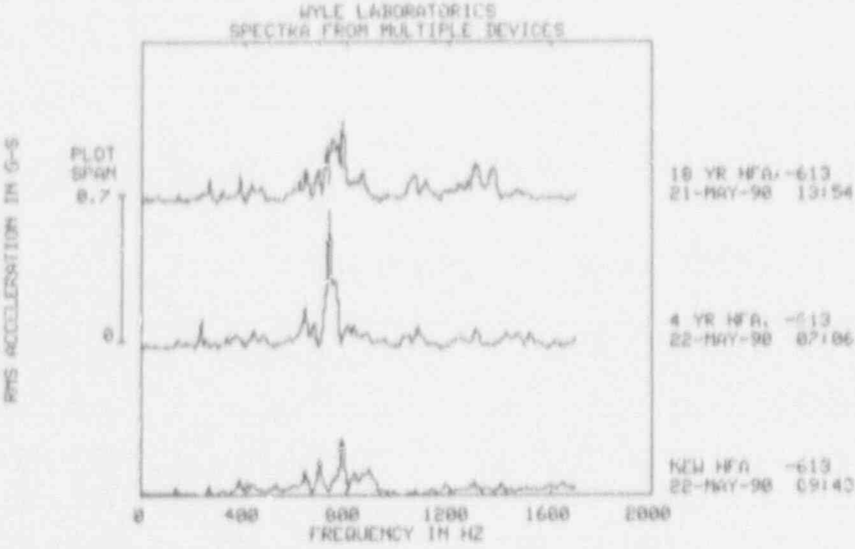


Figure 3-42. Vibration Signatures of GE HFA Auxiliary Relays

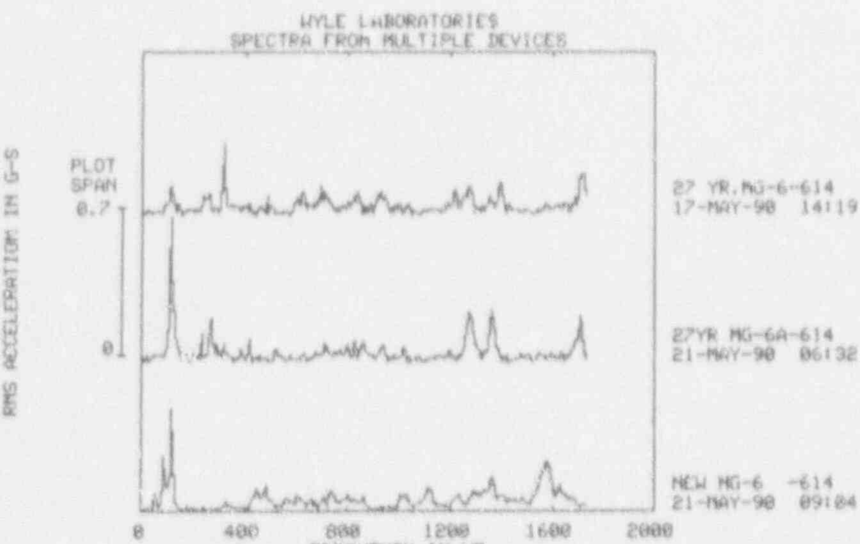


Figure 3-43. Vibration Signatures of Westinghouse MG-6 Auxiliary Relays

3.5 Timing Relays

Seven Agastat timing relays were evaluated in Phase II. These devices are common relays used in nuclear power generating stations. The specimens varied in age from four to twenty-three years old.

The most significant findings on the timing relays were :

- o After energization, the pick-up voltage on three of the seven timing relays was out of typical acceptance criteria,
- o There was a trend towards increased pick-up voltage with age,
- o There was a trend towards increased temperature with age noted by infrared scanning.

Sixteen ISM methods were evaluated on the timing relays. The methods included visual inspection, contact resistance, coil resistance, magnetic flux, insulation resistance, pick-up voltage, drop out voltage, inrush current, holding current infrared pyrometry, infrared scanning, on-contact temperature, current surge comparison, vibration testing, acoustic testing and ion detection. The following results were obtained for the timing relays in the condition in which they were received for this phase II effort:

Visual Inspection

The timing relay specimens were Agastat "On delay" electropneumatic timing relays, with an on delay on pick-up. The Agastat timing relays were composed of three elements, a timing head, wound potted coil, and the switch assembly. The switch assembly contained two N.O. and two N.C. contacts, which were made of silver cadmium oxide mounted on beryllium copper blades. The terminations for these specimens were all on the front of the relay. All had a bracket on the back for mounting to a panel. The models and ages were: two model 7012AA, 8 years; two models 7012AC, 8 and 10 years; one model E7012AB, 4 years; one model 2412AD, 23 years; and one model 2412AN, 23 years.

All timing relays had time dial settings on the top except for the 2412AN, which had an adjusting screw. The two 23 year specimens had grey cases and the others had black cases. The date of manufacture was stamped on each relay. The name plate on the

2412AD was deteriorated and hard to read. Each relay had a spindle cover on the bottom over the spindle except for the two 23 year specimens which had no cover. All relays appeared in good condition. No foreign material or metal debris was observed on the relays. There were no signs of moisture or other environmental contaminants in the relays. The coils were rated for 120 VAC and the contacts were rated for 10 amps at 240 VAC.

The visual inspections on the timing relays showed no obvious problems existed and all appeared to be in good condition. Figures 3-44 and 3-45 show the 4 year E7012AB and 23 year 2412AN, respectively.

Contact and Coil Resistance

The contact resistance was measured in the as received condition for each specimen and after testing the other ISM methods. The lowest to highest resistances measured for the contact sets of each relay were summarized in Figure 3-46 for the as received initial condition and in Figure 3-47 for the post test condition. The contact resistance did not change significantly with age.

Coil resistance was measured on each timing relay at four different times during the tests on aged devices. The four times were first, in the as received condition, at the start of the ISM methods; second, after the relay had been energized for 2 hours; third, after the coil had been allowed to cool to ambient after ISM methods of pick-up, drop out, inrush and holding current; fourth, after the relay had been energized for 2 hours. The coil resistance was recorded at five second intervals for one minute, after the 2 hour energized period.

The coil resistance for each of the timing relays remained stable during all measurements.

No significant differences with age were found in the contact and coil resistance of the timing relays.

Magnetic Flux

The relay specimens were measured at 85%, 100%, and 110% of rated coil voltage and were plotted in Figure 3-48 showing the value at 80% voltage at the bottom and the value at 110% voltage at the top of each band. The differences in magnetic flux were not considered to be significant and no correlation with significant results of other ISM methods were found.

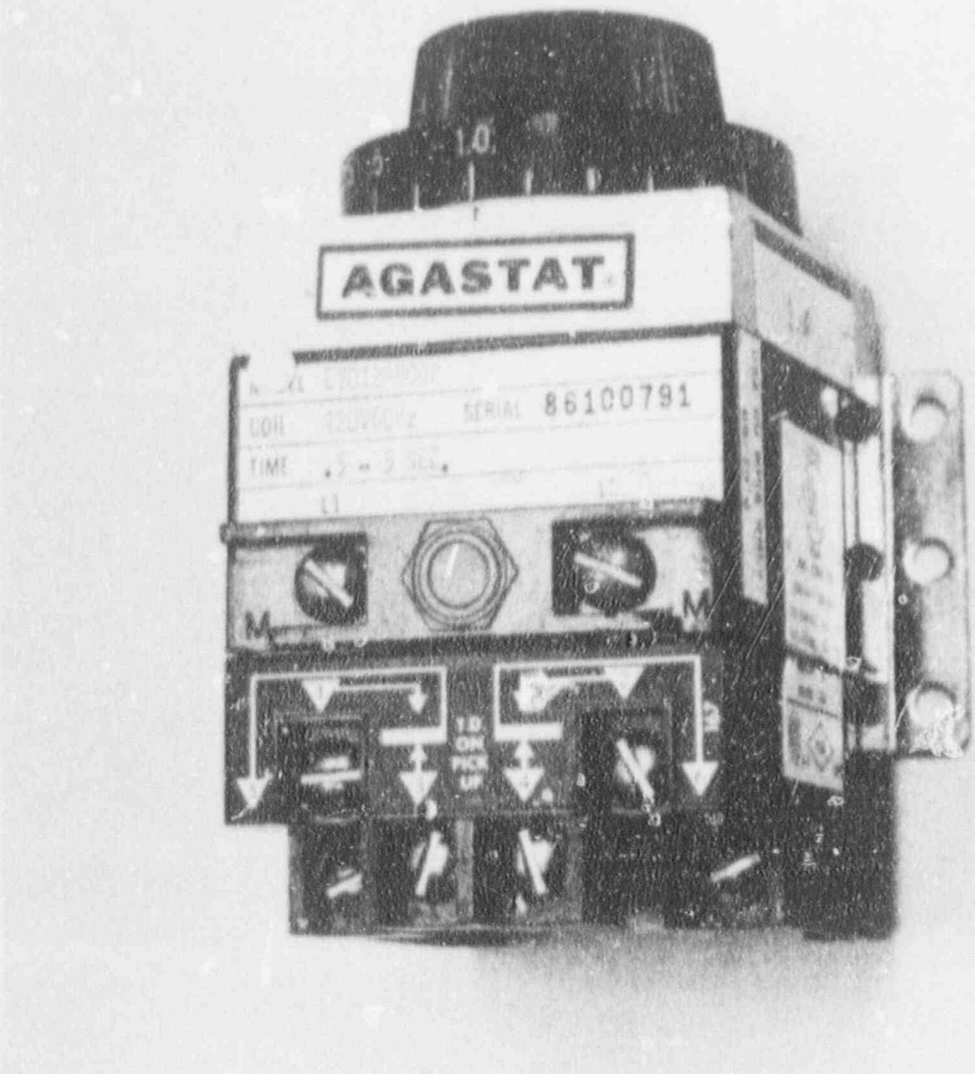


Figure 3-44. Agastat E7012 AB002
Timing Relay

Figure 3-45. Agastat 2412AN
Timing Relay

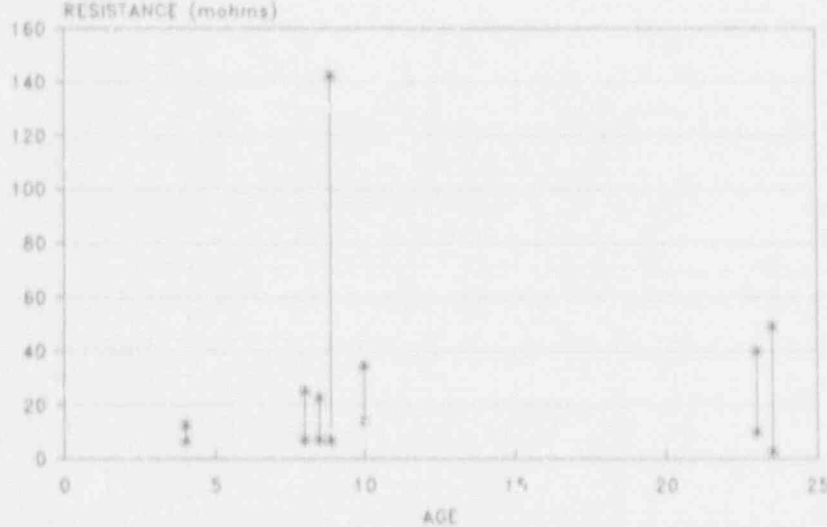


Figure 3-46. Initial Contact Resistance
Comparison Timing Relays

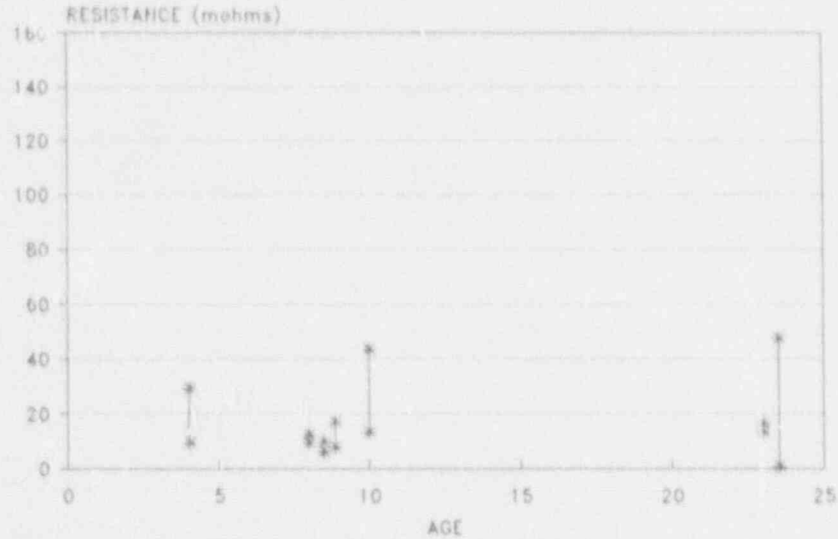


Figure 3-47. Post Test Contact
Resistrnce Comparison Timing Relays

Insulation resirtance

Insulation resistance values of adjacent contacts and contact to ground all exceeded 1.1 E9 ohms. Insulation resistance differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Pick-up and Drop out Voltage

The pick-up voltages for the timing relays were taken three times when the relay was at ambient conditions in the as received condition and three more times after it had been energized for 2 hours, Figure 3-49. The pick-up voltage on the 8 year 7012AC timing relay was out of the typical acceptance criteria of 102 volts in the as received condition. After energization for 2 hours, the pick-up voltage increased for four out of the seven timing relays. The pick-up voltages on the 8 year 7012AC, 10 year 7012AC and 23 year 2412AN relays exceeded the typical acceptance criteria.

During pick-up voltage testing, contact sequence was monitored to determine any deviation from simultaneous operation. There was no discernable contact closure pattern on pick-up for any of the timing relays.

The drop out voltages for the 4 year E7012AB, 23 year 2412AN and 2412AD exceeded the typical acceptance criteria of 50% rating, Figure 3-50.

The significant result for pick-up voltage was the trend towards increased pick-up voltage requirements with age and the increase in pick-up voltage requirements after energization on over half of the specimens. For drop out voltage, the result of the 23 year specimens being out of typical specifications may indicate a trend with age. The ISM methods of timing and current surge comparison were correlated with the significant results of pick-up and drop out voltage for the 23 year timing relays.

Inrush and Holding Current

Differences in inrush and holding current for the timing relays were not significant, Figure 3-51. No trend with age and no correlation with significant results of other ISM methods were found.

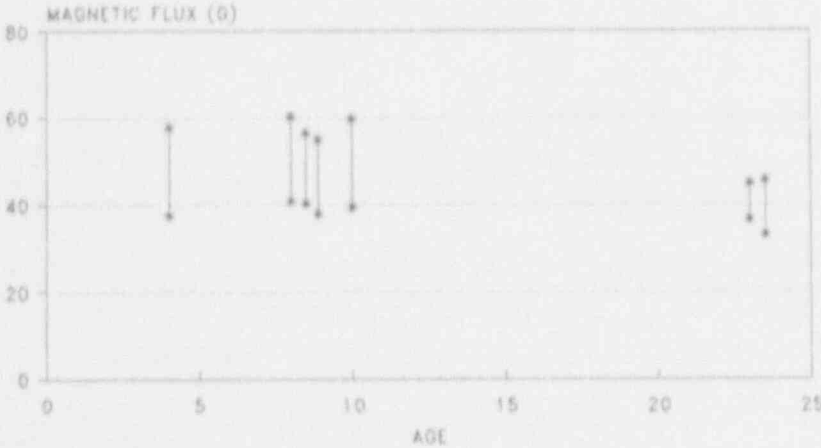


Figure 3-48. Mo[illegible] Field
Comparison Timi[illegible] [illegible]elays

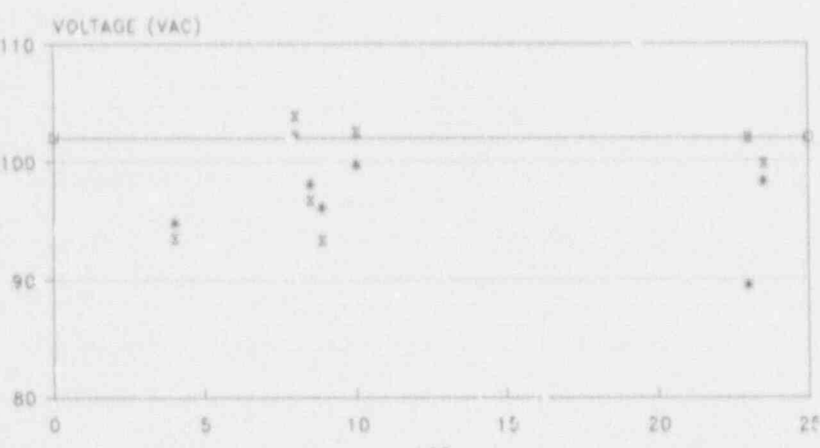


Figure 3-49. Pick-up Voltage
Comparison Timing Relays

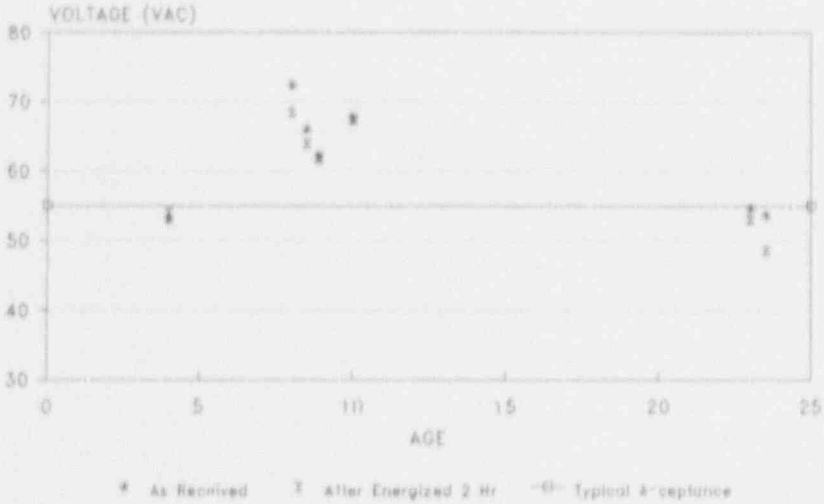


Figure 3-50. Drop Out Voltage
Comparison Timing Relays

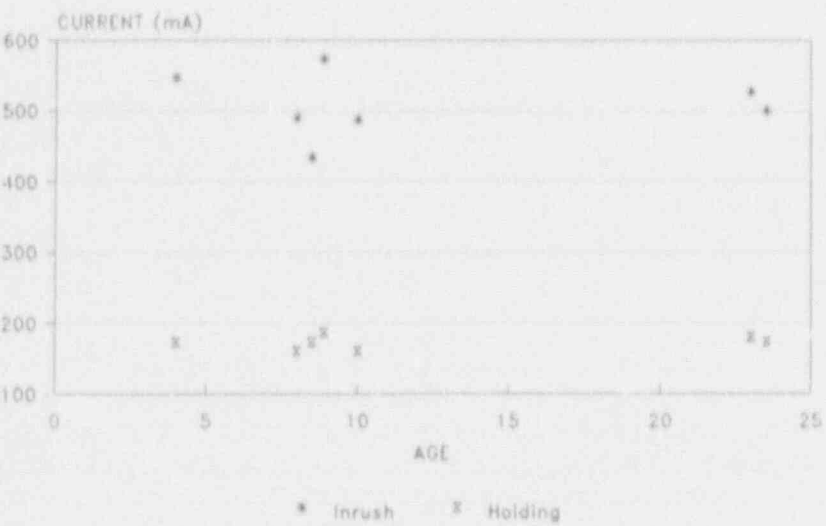


Figure 3-51. Inrush and Holding Current
Comparison Timing Relays

Timing

The timing relay specimens operate by providing a delay period on energization, at the end of which, the switch transfers the load from one set of contacts to the other. The timing method was accomplished by measuring the time between energization of the coil and the time at which contact transfer occurred. This test was performed at three different voltage levels, 85%, 100%, and 110%. The percent change from time dial setting to the actual time of transfer is shown in Figure 3-52. The typical repeat accuracy specification is ±10%. All timing relays were within this accuracy except for the 23 year 2412AD. Also, the 2412AN had no time dial setting, so it was initially measured to be 15 seconds and did not change during the testing. The increase in change from time dial setting for the 23 year 2412AD was correlated to changes in current surge comparison and temperature.

Infrared Pyrometry

The maximum temperatures measured for the timing relays are shown in Figure 3-53.

Infrared pyrometry did not show significant differences among the devices, except that the 23 year 2412AD had the hottest temperature but this was only 5°F hotter than the 4 year E7012AB.

Infrared Scanning

The scanner showed the maximum temperatures, Figure 3-53, to be hotter than the pyrometer and on-contact methods for all seven relays. A trend towards increased temperature with age was noted with the scanner. The 23 year 2412AD relay was the hottest relay.

On-contact Temperature

The maximum temperatures obtained are shown in Figure 3-53. The on-contact method pinpoints a spot, therefore the area of the hottest spot was overlooked on the 8 year 7012AC, 10 year 7012AC and 23 year 2412AD, because it was on the case in an area not near the contacts, which were suspected to contain the hottest spot. Thus the on-contact method did not show the trend towards increased temperatures with age that was noted with the scanner.

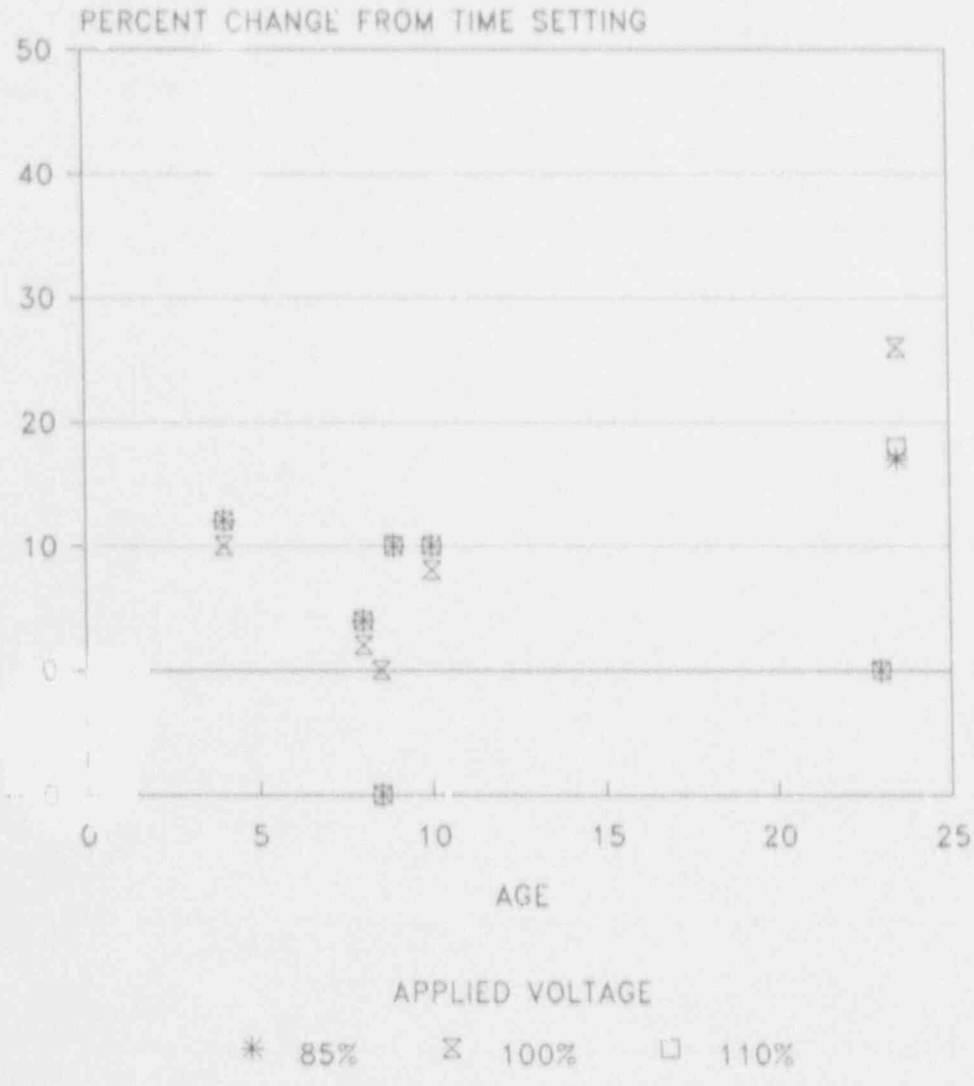


Figure 3-52. Timing
Comparison Timing Relays

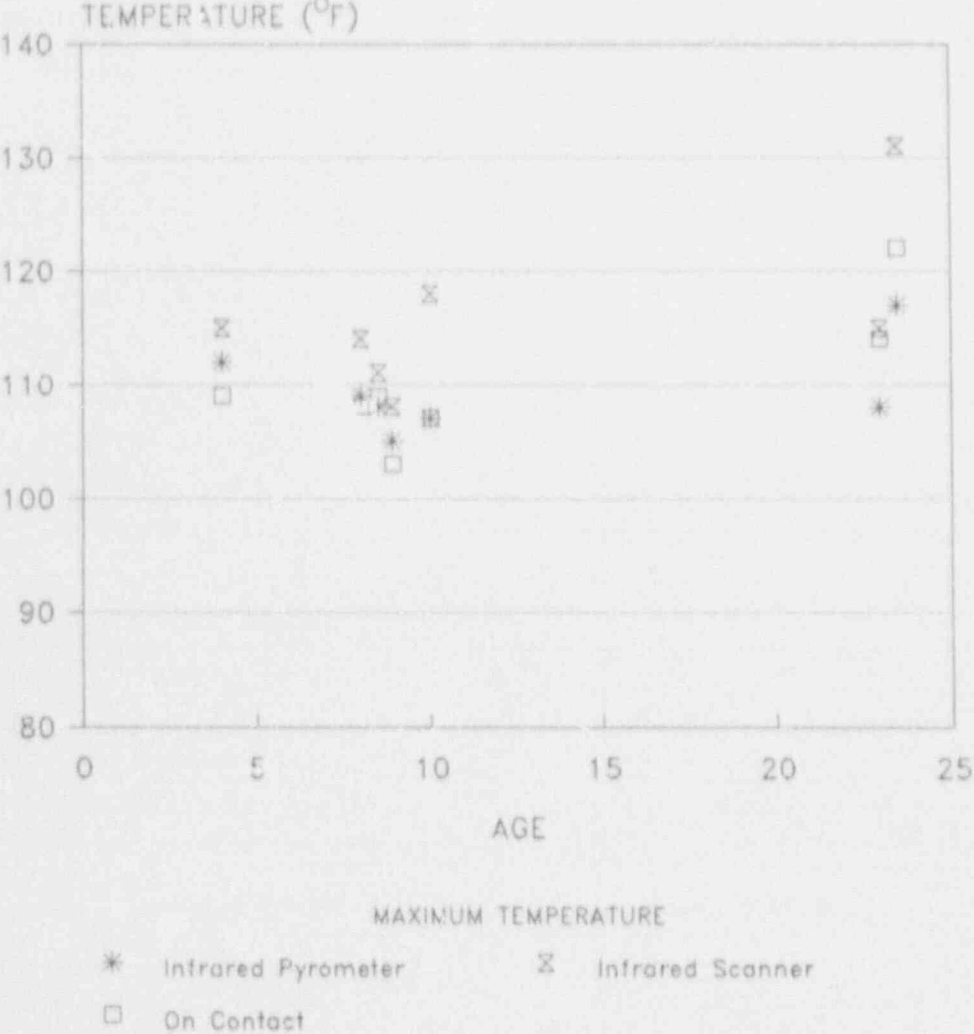


Figure 3-53. Temperature Comparison Timing Re ays

Current Surge Comparison

Ringing was noticeable on the two 23 year timing relays, which may be due to aging of the coil insulation, but could be due to differences in the manufacturing process. The waveform comparison is shown in Figure 3-54 for the 23 year 2412AD, which had the most noticeable ringing. The current surge comparison on timing relays may indicate a trend with age.

Vibration Testing and Acoustic Testing

Vibration signatures were obtained during the pick-up tests. The vibration signatures were repeatable and differences noted among the different aged specimens of timing relays. Differences in the vibration signatures were mainly in the range from 90 Hz to 400 Hz.

Acoustic signature differences were noted among the timing relays. The differences were mainly in the peaks at 110, 430, 700 and 800 Hz.

Vibration and acoustic signatures of aged specimens were different. The differences suggest that aging was influencing the characteristics of the signatures.

Ion detection

Two ionization smoke detectors were mounted adjacent to each specimen during the above tests which required energization of the specimens. The detectors never alarmed.

The lack of ion detector alarm indicates that no significant concentration of ionized particles had outgassed from the specimens due to age.

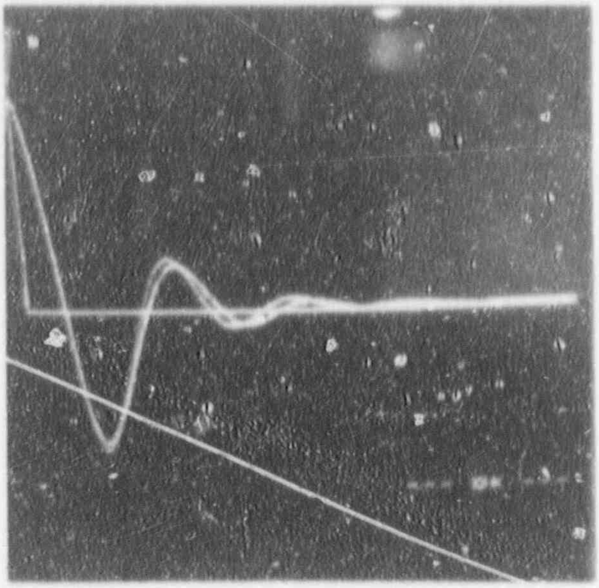


Figure 3-54. Current Surge Comparison
on 23 Year Old 2412AD Timing Relay

3.6 Molded Case Circuit Breakers

Eleven molded case circuit breakers representing four manufacturers were evaluated in this study. These devices were safety-related circuit breakers which had come from a variety of sources including nuclear power plants. The specimens were Square D FAL36070 and KAL36150, which were six years old; two Westinghouse AB DE-ION, F-Frame, style No. 1222077A, which were 30 years old; Westinghouse HFB 3045 and two 31550's, which were 18 years old; Klockner-Moeller NZMH6-40 and NZMH6-100, which were 10 years old; General Electric TFJ224150, which was new; and ITE KMB2F800 which was 8 years old.

The most significant results on the molded case circuit breakers were as follows:

- o Evidence of discoloration and overheating on pole 1 of the ITE KMB2F800,
- o Overheating on the ITE KMB2F800 had caused distortion and damage to the thermal element of pole 1, which caused it to conduct overcurrent longer than specified before tripping in the 300% overcurrent trip method,
- o Overheating on the ITE KMB2F800 had rendered the instantaneous trip mechanism inoperable on pole 1 and significantly out of specification on pole 2. Overcurrents as high as 22,000 Amps failed to trip pole 1 and 9,160 Amps was needed to trip pole 2. The specification for instantaneous trip required a trip at 5,600 Amps,
- o Confusing labels and discoloration on the case of the Klockner-Moeller NZMH6-40,
- o Overheating on the Klockner-Moeller NZMH6-100 caused heat shrink tubing on the trip mechanism to shrink, split, and interfere with the trip mechanism, which caused it to conduct overcurrent longer than specified before tripping in the 300% overcurrent trip method,
- o A damaged and misaligned trip pin on the Klockner-Moeller NZMH6-40, caused the breaker to overheat, melt and fail to open the circuit during the instantaneous trip method. The damage to the trip pin suggests improper maintenance in the installation of the trip unit,
- o A missing spring on the Westinghouse HFB 31550 rendered the instantaneous trip mechanism inoperable,

- Infrared Thermography showed that maximum temperatures reached between 341°F and 584°F on the circuit breakers when they experienced problems during the instantaneous method.

- The ion detection method was ineffective at detecting significant smoke outgassing from some of the devices and their attached insulations due to lack of concentration of the smoke in the vicinity of the detectors.

Sixteen ISM techniques were evaluated on the molded case circuit breakers. They were visual inspection, pole resistance, insulation resistance, mechanical actuation, 100% rated current hold-in, 135% rated current hold-in, 300% overcurrent, 600% overload, instantaneous trip, dielectric, infrared pyrometry, infrared scanning, on-contact temperature, vibration testing, acoustic testing, and ion detection.

The following results were obtained from the circuit breakers in the condition in which they were received for this effort.

Visual Inspection and Mechanical Actuation

All molded case circuit breakers were visually inspected for name plate information, condition of terminal lugs, condition of circuit breaker case (i.e. cleanliness, evidence of flashover or arcing), sealing compound on countersunk hold-down screws if applicable (to indicate evidence of tampering), signs of overheating (discolored metal, odor, or melted insulation), and opening and closing action.

The Square D FAL 36070 was a three pole 70 amp, fixed instantaneous circuit breaker rated for 600 VAC. The specimen showed no signs of physical damage or missing parts. The circuit breaker was new in appearance and had a crisp action on both the opening and closing action. The trip button was pressed and the circuit breaker moved to the tripped position. The circuit breaker reset with no binding.

The Square D KAL 36150 was a three pole 150 amp, adjustable instantaneous circuit breaker rated for 600 VAC. The magnetic adjustment range was 750 amps to 1500 amps. The specimen showed no signs of physical damage or missing parts. The sealing compound covering the back screws of the circuit breaker was present and undamaged. The circuit breaker was new in appearance and had a crisp movement on both the opening and closing action. The trip button was pressed and the circuit breaker moved to the tripped position. The circuit breaker reset with no binding.

The Westinghouse AB DE-ION circuit breakers were 100 amp, 600 VAC adjustable magnetic trip only. The magnetic adjustment range was 500 amps to 1500 amps. The specimens were extremely dusty but showed no signs of physical damage or missing parts. There were no signs of electrical damage such as melting insulation or discolored terminal lugs and the closing and opening actions were crisp. The sealing compound covering the back screws of the circuit breaker was present and undamaged. Figure 3-55 shows a 30 year Westinghouse AB DE-ION, Style Number 1222077A mounted for testing.

The Klockner-Moeller NZMH6 circuit breakers were 40 amp and 100 amp, 600 VAC with both adjustable magnetic trip and adjustable thermal trip units. The magnetic adjustment range was 160 amps to 320 amps for the 40 amp circuit breaker and 600 amps to 1200 amps for the 100 amp circuit breaker. The thermal trip range for the 40 amp specimen was 25 to 40 amps and the 100 amp circuit breaker was 63 to 100 amps. The 40 amp breaker had two labels. One label was on the thermal and magnetic trip assembly, which stated that it was a ZM6-40, 40 amp breaker. The other label was on the contact and trip arm assembly, which noted that it was a NZMH6-63, 100 amp breaker. The specimens had some chips in the case near the top terminals. The prior history of these specimens had included testing at high temperatures and therefore the clear polycarbonate cases had discolored to a yellowish color. There were no signs of electrical damage such as melting insulation or discolored terminal lugs and the closing and opening actions were crisp.

The General Electric TFJ224150 circuit breaker was a 150 amp, 480 VAC with an adjustable magnetic trip. The magnetic adjustment range was 700 amps to 1500 amps. The specimen was clean and showed no signs of physical damage or missing parts. There were no signs of electrical damage such as melting insulation or discolored terminal lugs and the closing and opening actions were crisp. The sealing compound covering the back screws of the circuit breaker was present and undamaged. The trip button was pressed and the circuit breaker moved to the tripped position. The circuit breaker reset with no binding.

The ITE KMB2F800 was a 800 amp, 600 VAC adjustable magnetic trip circuit breaker. The adjustable magnetic trip range was 3200 to 5600 amps. The specimen was clean except for dust on the top near the arc chutes and dust and cobwebs inside the cover on the line side of the breaker. The load and line poles of pole number one were significantly discolored and had evidence of having been overheated. The operating handle was cracked at the base. The breaker was manually closed and then opened with the manual trip button, which operates the instantaneous trip mechanism for pole number 2. The breaker operated properly when manually set, tripped and reset. The history of this breaker was that it had been tripping at less than rated loads, which had been traced to a loose

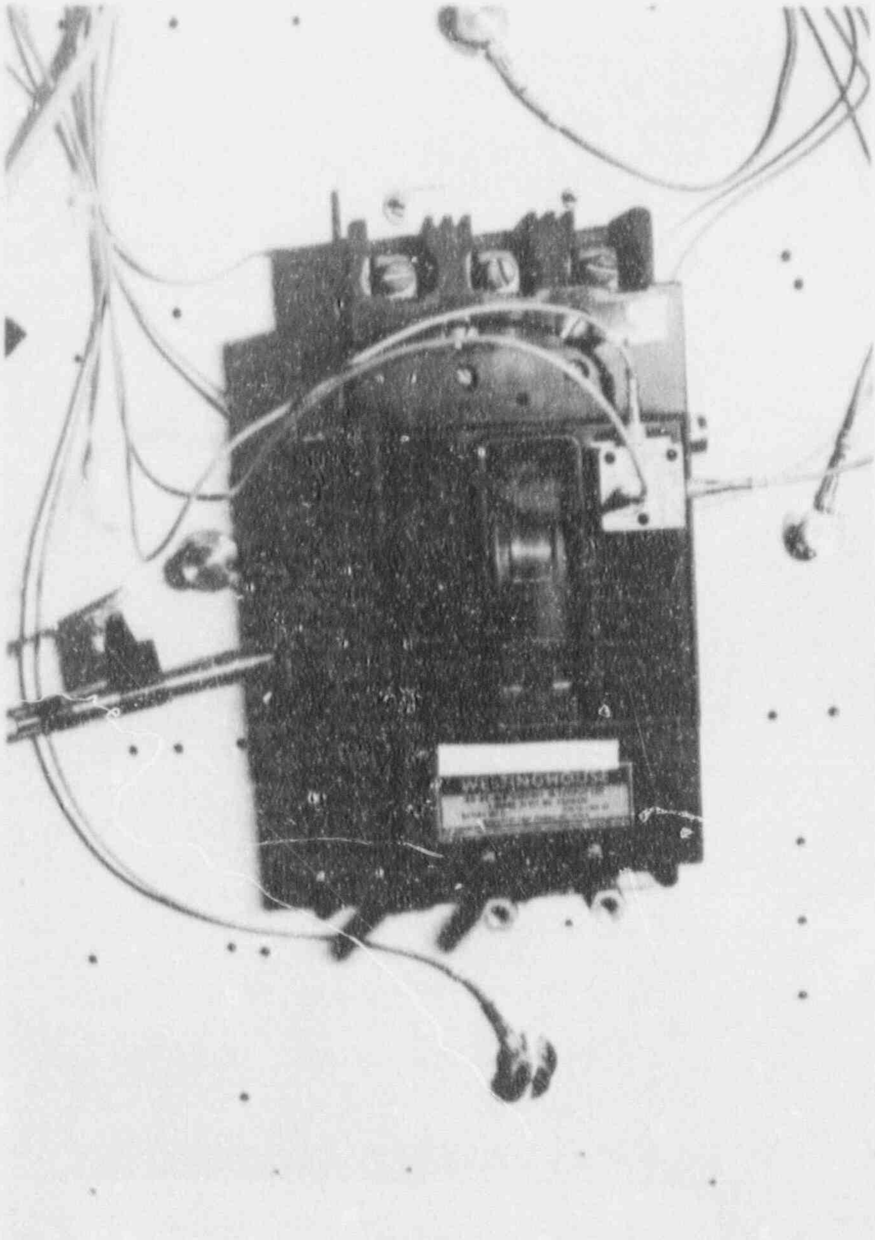


Figure 3-55. Westinghouse AB DE-ION Style 1222077A Molded Case Circuit Breaker Showing Location of Vibration Accelerometers and Acoustic Microphone

connection on the incoming bus, after the breaker had been replaced. Figure 3-56 shows the KMB2F800 and Figure 3-57 shows the differences in color between the overheated pole 1 and normal pole 2.

The three Westinghouse HFB circuit breakers were one HFB3045, 5 amp and two HFB31550, 100 amp, 600 VAC adjustable magnetic trip only circuit breakers. The magnetic adjustment range was 500 amps to 1500 amps for the 100 amp specimens and 15 to 45 amps for the 5 amp breaker. The specimens were extremely dusty but showed no signs of physical damage or missing parts. There were no signs of electrical damage such as melting insulation or discolored terminal lugs and the closing and opening actions were crisp. The sealing compound covering the back screws of the circuit breakers was present and undamaged. The Westinghouse "Factory Sealed Breaker" sticker was present and undisturbed on the HFB 31550 breakers but was missing on the HFB3045 breaker.

The significant results of the visual inspections on the molded case circuit breakers were the evidence of overheating on pole 1 of the ITE KMB2F800 circuit breaker, the discoloration of the case on the Klockner-Moeller NZMH6 circuit breakers and the two confusing labels on the NZMH6-40 circuit breakers, otherwise all appeared to be in good condition.

Pole resistance

The pole resistance was measured in the as received condition for each specimen and after testing the other ISM methods. The highest resistances measured for the poles of each circuit breaker were summarized in Figure 3-58 for the as received initial condition and for the post test condition. The pole resistance of one of the HFB breakers was 139 mohms and one of the poles of a 30 year breaker was 537 mohms. The pole resistance showed a trend towards increased resistance with age. Lack of operation appears to contribute to this increase in pole resistance since the initial values were higher than the value obtained after the ISM methods had been performed. Pole resistance in general did not correlate with problems noted in the other ISM techniques except for the temperatures noted on the 30 year breaker with high resistance.

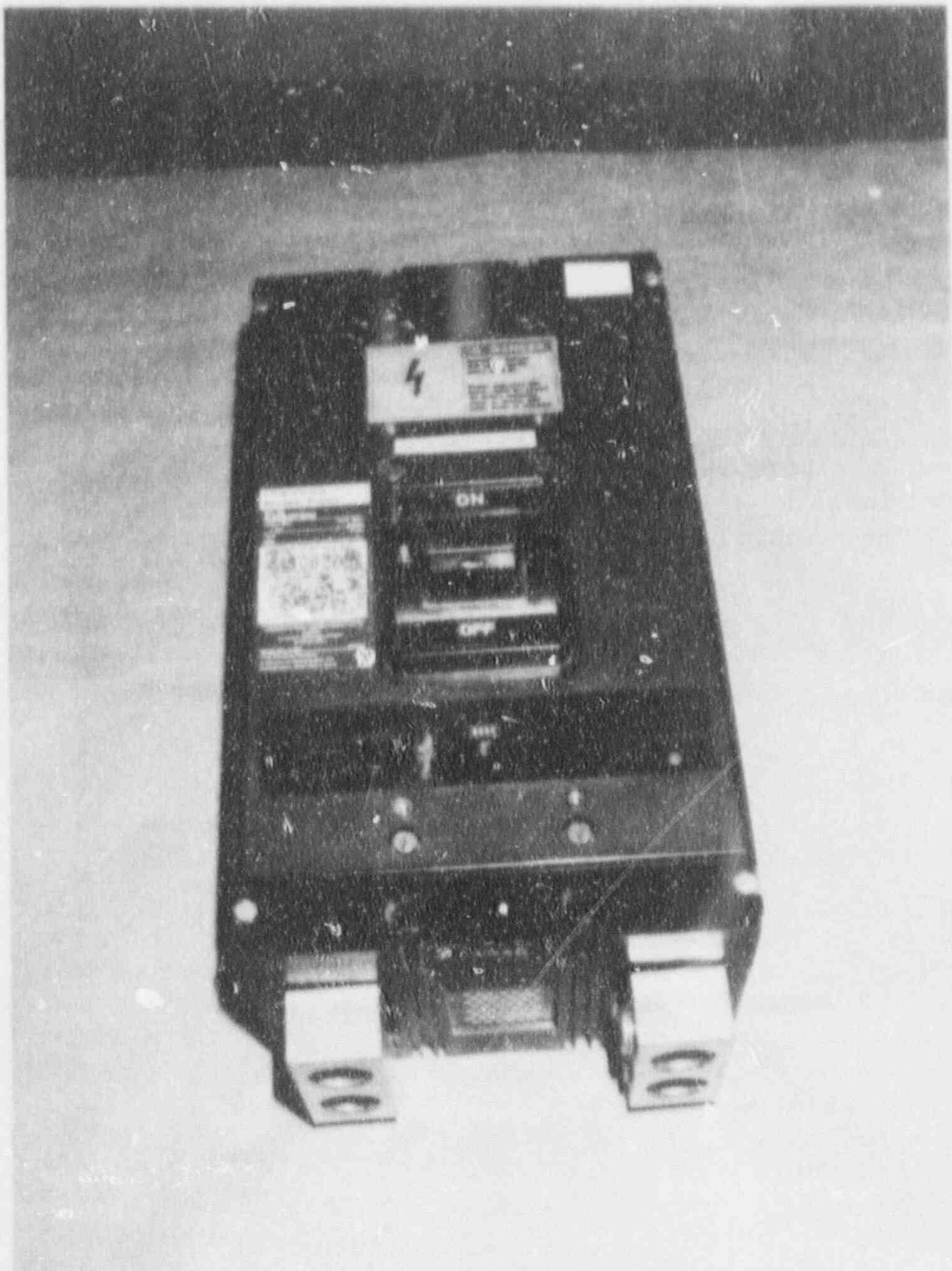


Figure 3-56. ITE KMB2F800, 800 Amp
Molded Case Circuit Breaker

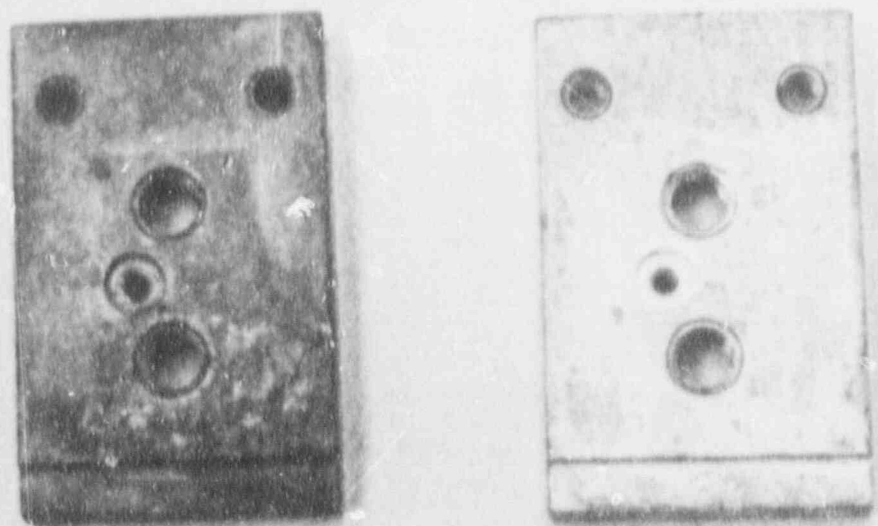


Figure 3-57. Overheated Pole 1 Compared to Pole 2 of ITE KMB2F800 Molded Case Circuit Breaker (Pole 1 on Left)

Insulation resistance

Insulation resistance was measured four times: between line and load terminals with the circuit breaker open; between poles with the breaker closed; between all poles and ground with the breaker open and between all poles and ground with the breaker closed. The minimum resistance was 8 E8 ohms and insulation resistance differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

100% Rated Current Hold-In

The three HFB and two AB DE-ION 30 year breakers were not tested for rated current since they were magnetic, instantaneous, breakers and have no thermal element which would cause them to trip during the 100% test. All circuit breakers tested maintained 100% rated current without interruption. No trend with age and no correlation with significant results of other ISM methods were found.

135% Rated Current Hold-In

Only those circuit breakers which had thermal elements were tested. Thus the three HFB and two 30 year breakers were not tested. The temperature of each breaker was monitored during this test and immediately after trip. During the 135% rated current tests, the temperature increased an average of $10^{O}F$ over the temperature measured in the 100% rated current test. All circuit breakers tripped within the test time except for the GE TFJ224150, which did not trip within the specified two hour time period. A root cause failure analysis did not result in any explanation for the out of specification condition except for the possibility that it was set this way at the time of manufacture.

300% Overcurrent

The results of the 300% overcurrent method were summarized for the circuit breaker specimens in Figure 3-59 and the performance of each pole of each breaker were compared in Table 3-1.

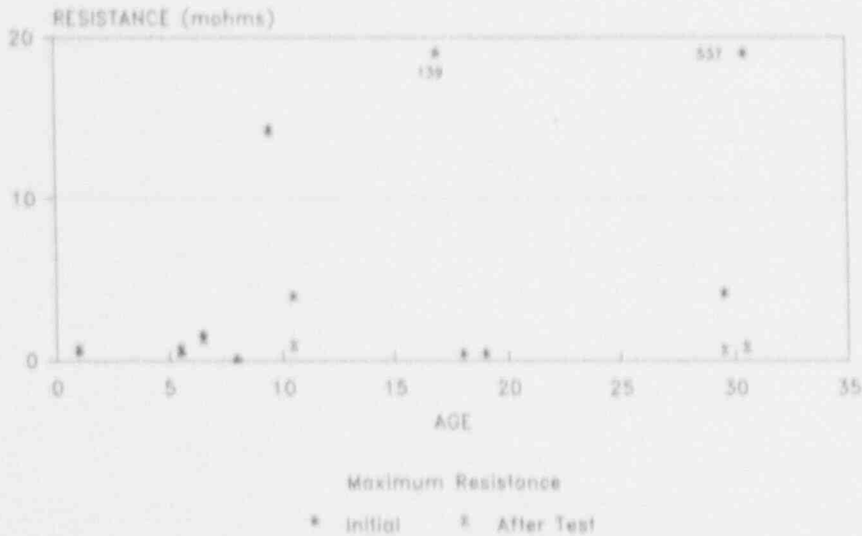


Figure 3-58. Pole Resistance
Comparison Molded Case Circuit Breakers

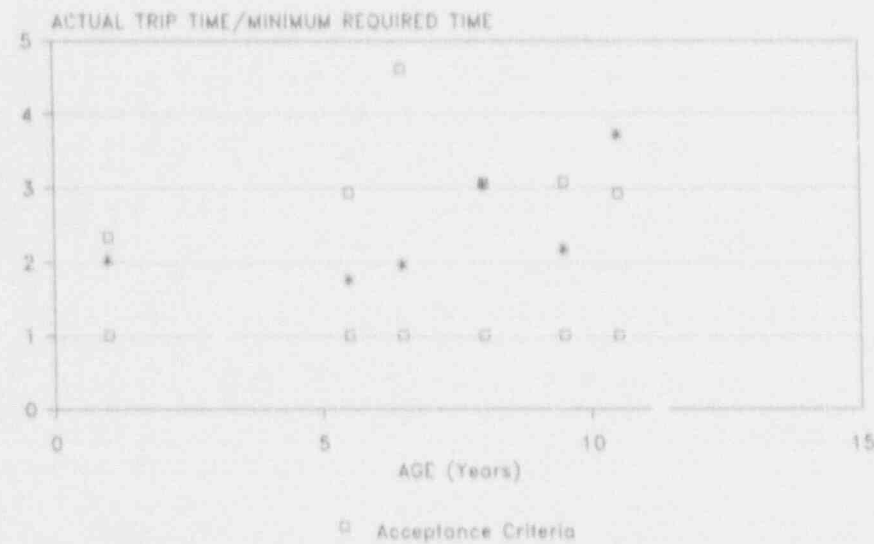


Figure 3-59. 300% Overcurrent
Comparison Molded Case Circuit Breakers

Table 3-1. Time Delay at 300% Overcurrent

Manufacturer & Model	Time Delay			Acceptance Criteria (Seconds)
	Pole 1 (Seconds)	Pole 2 (Seconds)	Pole 3 (Seconds)	
[illegible]	60.8	55.9	N/A	30 to 70
[illegible]	136.5	91.3	N/A	45 to 136.5
[illegible] Z[illegible]	28.2	26.8	28.1	13 to 40
[illegible] 00	47.0	44.6	39.2	12 to 35
Square [illegible]6070	24.7	25.5	24.4	13 to 60
Square D [illegible]36150	120	105	101	60 to 175

In Figure 3-59, the actual trip time was divided by the manufacturer's minimum required trip time from each manufacturer's trip curves for the pole with the greatest trip time. This allowed a comparison of all breakers tested. Two breakers had significant results. The 8 year ITE KMB2F800 circuit breaker was out of the manufacturer's specification on pole one. Additionally, the ten year Klockner-Moeller NZMH6-100 was out of specification on all three poles. The out of specification condition on both molded case circuit breakers allowed the breakers to conduct higher current for a longer period of time before the breakers interrupted the circuit.

A root cause failure analysis of the ITE KMB2F800 was performed. The root cause was overheating of the molded case circuit breaker, from a loose connection on the bus to the breaker. This overheating caused distortion of the thermal element of pole number 1. In Figure 3-60, the thermal element of pole 1 and pole 2 were compared. The thermal element on pole number 1 had deformed, developed a sharp corner instead of a rounded corner, and had taken a set which changed the angle of the element and the contact on pole 1. Additionally, the copper strips in the thermal element of pole 1 were discolored and dull. The copper strips in the thermal element of pole number 2 were shinny, had a rounded corner and more spring.

A root cause failure analysis of the Klockner-Moeller NZMH6-100 was performed. The root cause was also overheating. The overheating caused shrink tubing on all three poles to shrink further and interfere with the thermal element. The shrink tubing was located in the thermal and magnetic trip assembly in the base of the molded case circuit breaker. On pole number 1, the shrink

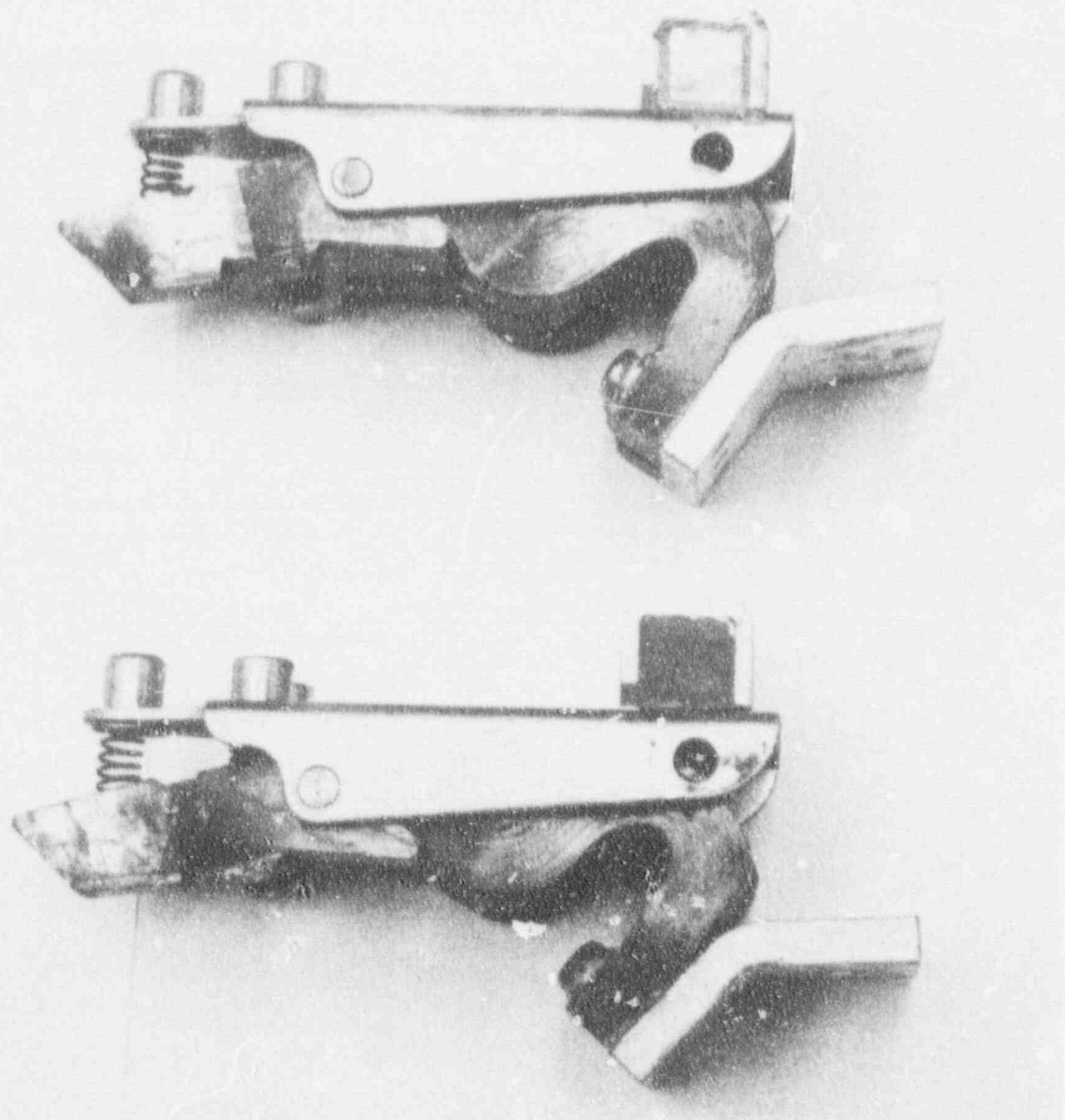


Figure 3-60. Thermal Trip Elements
of ITE KMB2F800 Molded Case Circuit Breaker
(Pole 1 on Bottom, Pole 2 on Top)

tubing had shrunk to the point that it had split and was wedged into and interfering with the thermal element of pole 1. The split heat shrink tubing of pole number 1 and shrunk tubing on poles 2 and 3 are shown in Figure 3-61.

The 300% overcurrent method detected a trend with age and identified age related failure mechanisms in the thermal trip elements of molded case circuit breakers. In each instance, the failure of the molded case circuit breaker was in a non-conservative manner.

600% Overload

Eight of the eleven circuit breakers were tested. The HFB breakers were not tested due to equipment availability. Only the Square D KAL36150 tripped automatically in this test. The other breakers were manually opened after 2 seconds. The average temperature increase due to this test was $6^{\circ}F$. No other significant effects were noticeable from this method. No trend with age and no correlation with significant results of other ISM methods were found.

Instantaneous Trip

The Square D FAL36070 was a fixed instantaneous breaker and therefore each pole was tested at 75% of the lower magnetic threshold of approximately 578 amps and 125% of the upper magnetic threshold, approximately 1837 amps. At the 75% point, the breaker should not trip instantaneously, defined by a trip time of greater than 0.1 seconds. At the 125% point, the breaker should trip with no intentional time delay, defined as less than 0.1 seconds.

The other circuit breaker specimens had adjustable instantaneous trip ranges. Each pole of these breakers was tested at four conditions. They were 75% of the lower magnetic threshold at the low setting of the magnetic adjustment, 125% of the upper magnetic threshold at the low setting of the magnetic adjustment, 80% of the lower magnetic threshold at the high setting of the magnetic adjustment and 120% of the upper magnetic threshold at the high setting of the magnetic adjustment. The trip time requirements for all models were below 0.1 seconds, which was used as the typical acceptance criteria.

Four out of the eleven molded case circuit breakers exceeded the typical 0.1 second acceptance criteria at the 125% test point, Figure 3-62. They were the 8 year ITE KMB2F800, 10 year Klockner-Moeller NZMH6-40, and the two Westinghouse HFB31550 molded case circuit breakers.

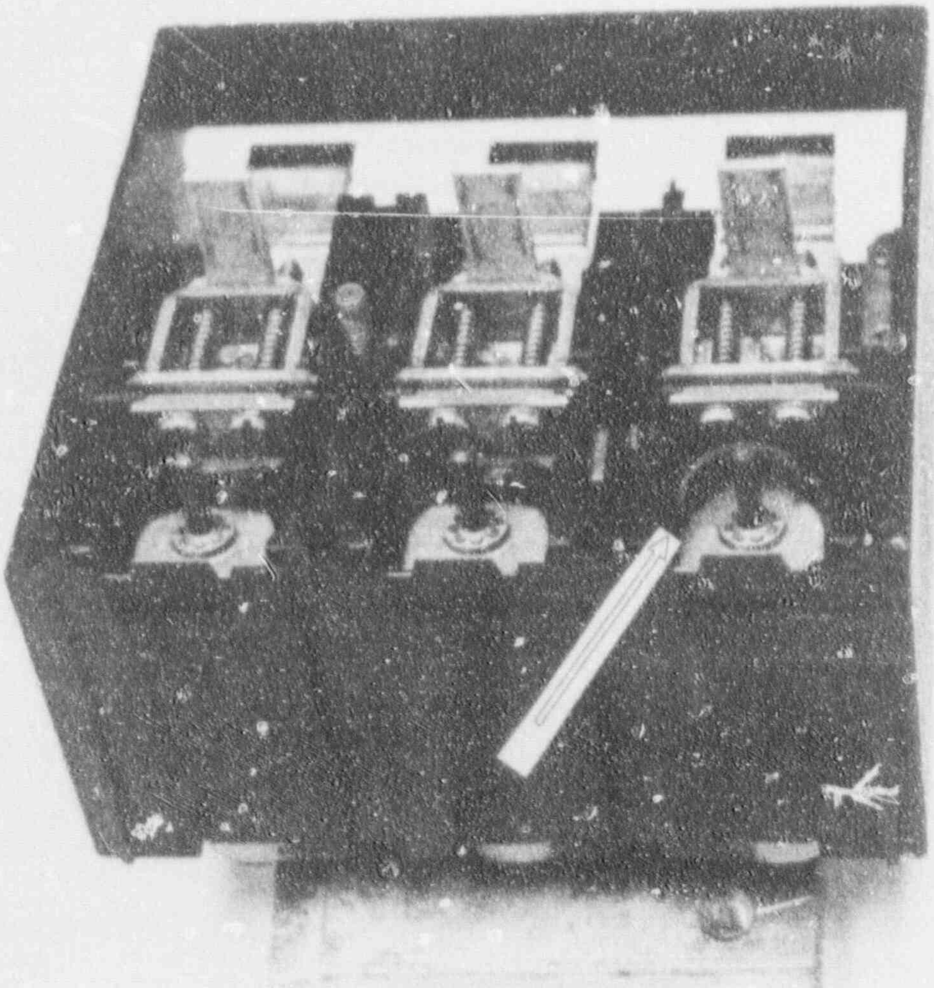


Figure 3-61. Root Cause Failure Analysis of Thermal and Magnetic Trip Assembly of Klockner-Moeller NZMH6-100 Molded Case Circuit Breaker, Showing Heat Shrink Tubing

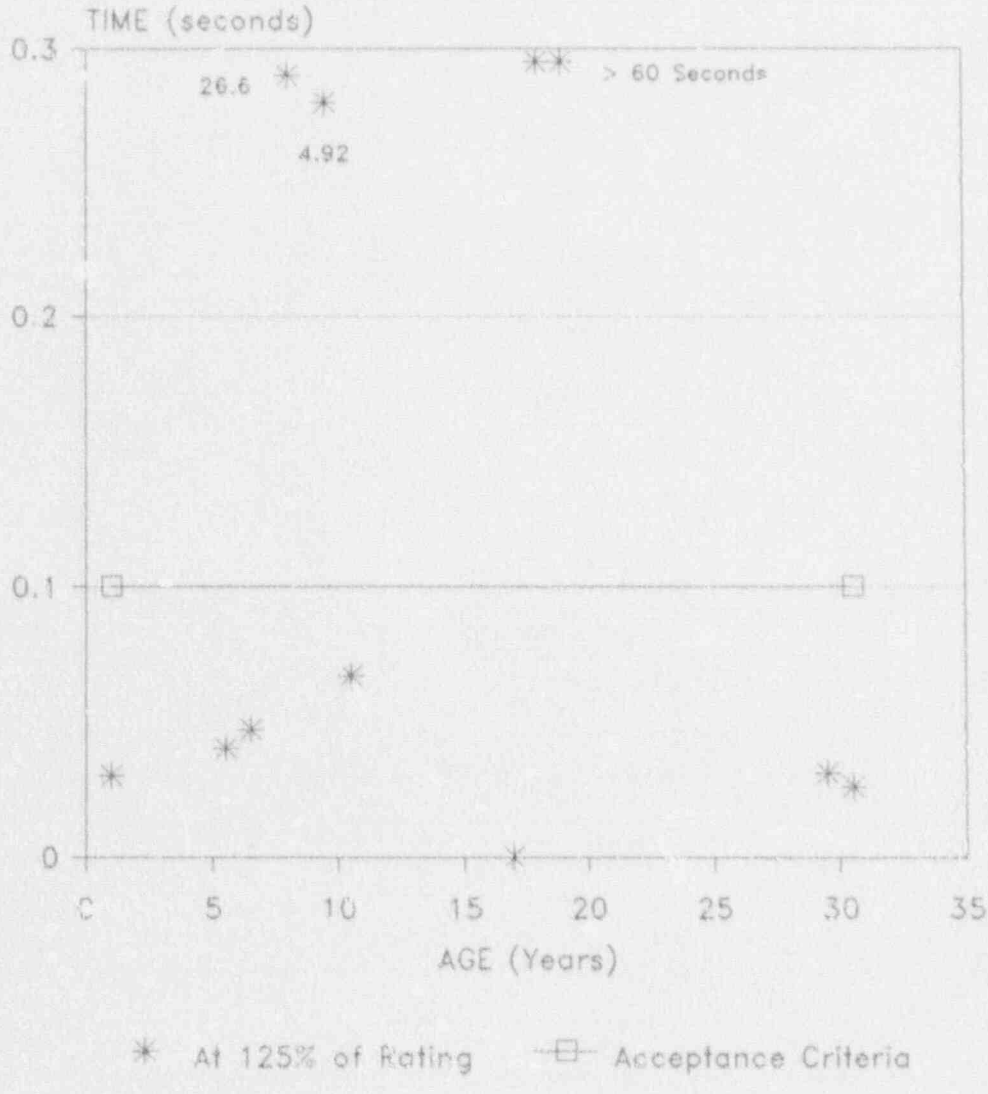


Figure 3-62. Instantaneous Trip
Comparison Molded Case Circuit Breakers

For the ITE KMB2F800, the trip time at 125% of the upper magnetic threshold at the low setting of the magnetic adjustment was 26.6 and 0.07 seconds for poles 1 and 2 respectively. At 120% of the upper magnetic threshold at the high setting of the magnetic adjustment, neither pole was less than 0.1 seconds. A current of 5600 amps should have caused an instantaneous trip. Pole 1 was tested as high as 22,000 amps, using a short duration current pulse, and never tripped instantaneously. Pole 2 tripped instantaneously at a current of 9,160 amps.

A root cause failure analysis of molded case circuit breaker ITE KMB2F800 was performed. The root cause was determined to be overheating from a loose connection on the bus to the breaker. This overheating caused different problems in pole 1 and pole 2. In pole 1, a foreign material, which appears to be grease, had cooked on a spot on the instantaneous trip assembly. This then interfered with the movement of the instantaneous plunger assembly and prevented it from full movement. The lack of full movement prevented the plunger from releasing the trip bar and the breaker never tripped instantaneously. The source of the grease was the magnetic trip adjustment cam. In Figure 3-63, the burned grease spot is shown and some excessive grease is shown on the side of the cam follower, which was in contact with the magnetic trip adjustment cam.

For pole 2, the overheating caused drying and solidification of lubricant on the instantaneous plunger assembly and prevented it from full movement when the magnetic trip adjustment cam was rotated to the high setting of the magnetic adjustment. In the test sequence, the molded case circuit breaker was tested manually. This manual test button is connected to the pole 2 instantaneous plunger. When the button was pressed, the magnetic trip cam was at or near its low setting. The low setting prepositions the instantaneous plunger assembly closer to the stationary core so that a lower current passing through pole 2 causes an induced magnetic field and draws the plunger assembly to the stationary core. When the plunger assembly approaches the stationary core, the plunger exerts a force on the trip bar and the breaker trips. When the magnetic trip cam was positioned to the high setting, the distance that the instantaneous plunger assembly has to move was increased and thus required a greater magnetic field to pull the plunger assembly to the core. In this instance, when the magnetic trip cam was positioned to the high setting, the instantaneous plunger assembly was moved into the solidified lubricant, Figure 3-64, which hung up the plunger assembly and required more force to move it. The result was higher current was needed to move the plunger and cause a trip to occur.

For the Klockner-Moeller NZMH6-40, the trip time at 125% of the upper magnetic threshold at the low setting of the magnetic

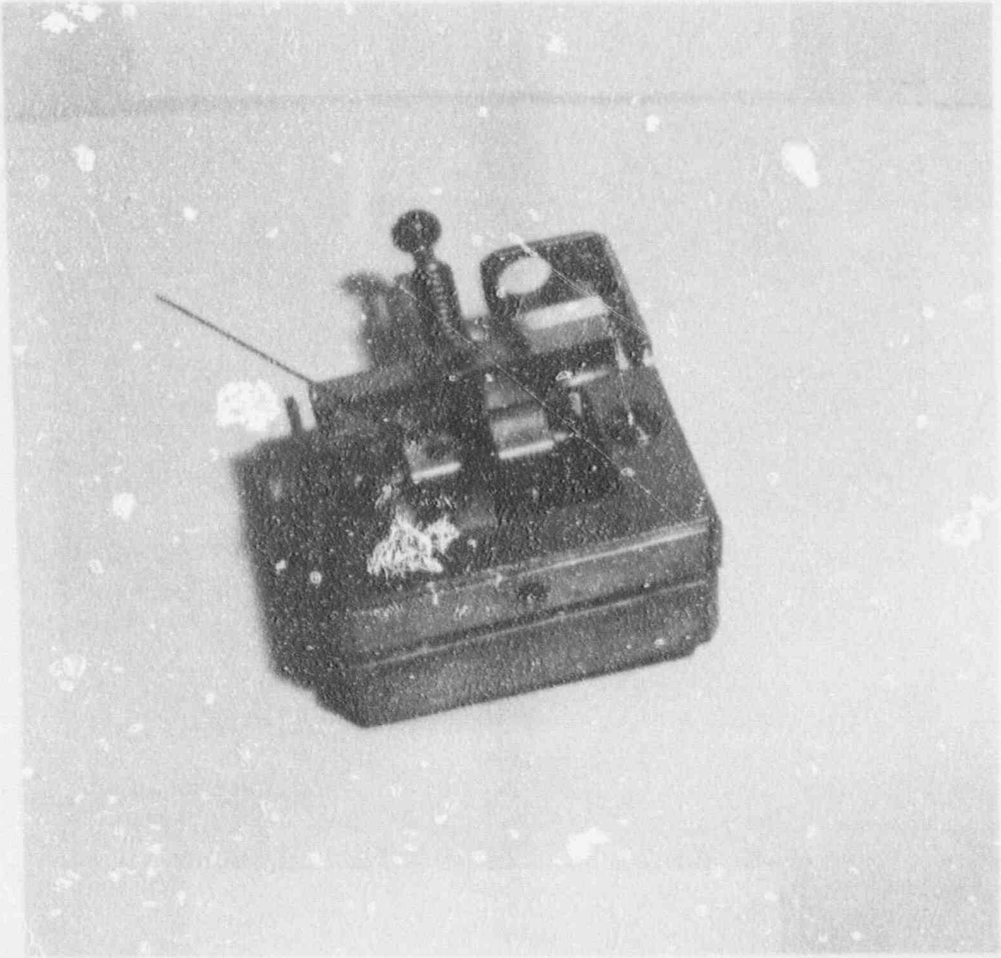


Figure 3-63. Root Cause Failure Analysis of Instantaneous Trip Plunger Assembly on Pole 1 of ITE KMB2F800 Molded Case Circuit Breaker, Showing Burned Spot

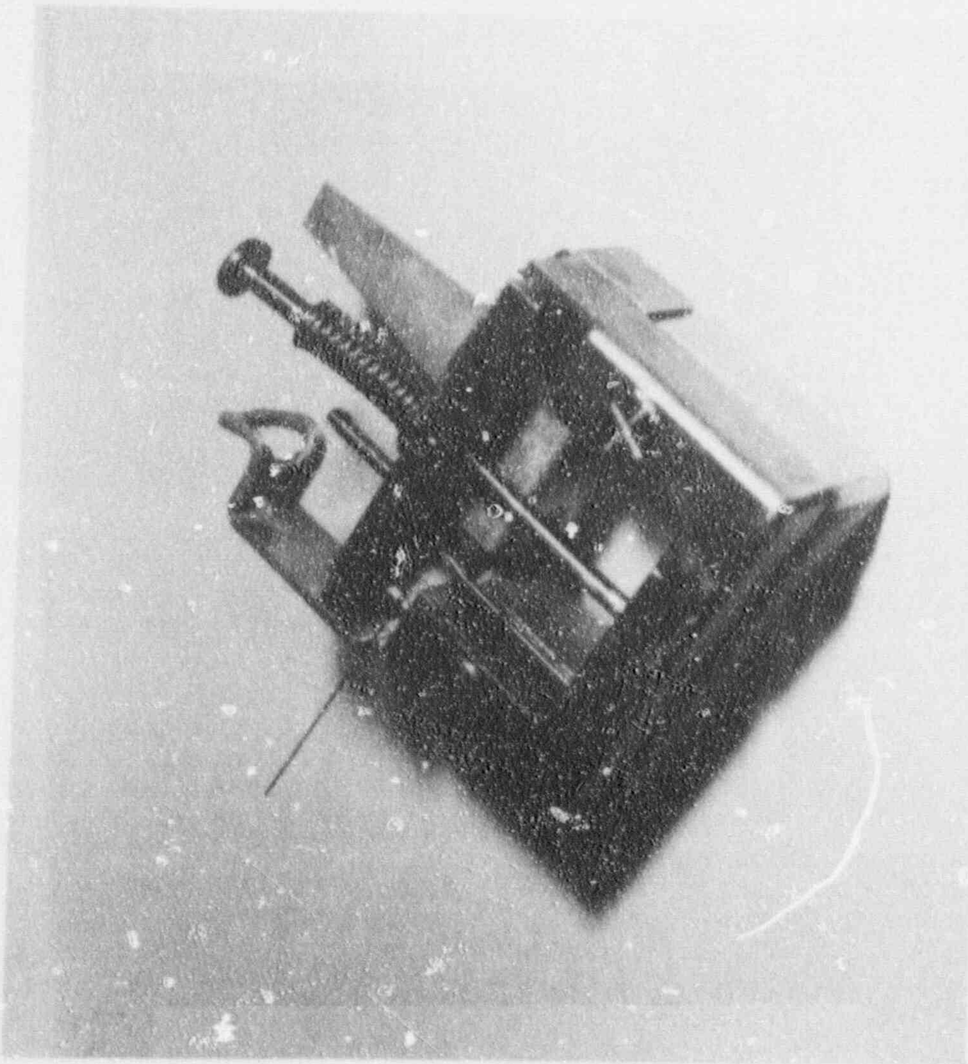


Figure 3-64. Root Cause Failure Analysis of Instantaneous Trip Plunger Assembly on Pole 2 of ITE KMB2F800 Molded Case Circuit Breaker, Showing Solidified Grease

adjustment was 0.033, 0.056 and 4.92 seconds for poles 1,2 and 3 respectively. The instantaneous trip current for pole number 3 was 844 amps at the 125% point. After further testing to determine the cause for high instantaneous trip, pole three overheated at 200(125%) amps and eventually melted and open circuited, Figure 3-65. The maximum temperature at pole three was 584°F.

A root cause failure analysis of molded case circuit breaker Klockner-Moeller NZMH6-40 was performed. The root cause was determined to be a misaligned and damaged magnetic trip pin on pole number 3. The instantaneous trip range on this style breaker was achieved by a dial and cam on the bottom of the thermal and magnetic trip assembly. This cam was connected to a trip pin which extends out of the thermal and magnetic trip assembly. With sufficient current, the trip pin extends and contacts the trip bar which is above the pin. The trip bar is a non-metallic and readily moves to trip the breaker. The trip pin on pole 3 was found to be bent, Figure 3-66, and sheared. The thermal and magnetic trip assembly had been noted in the visual inspection to be labeled for a 40 amp breaker and the contact assembly had been noted to be marked for a 63 amp breaker. This suggests that the thermal and magnetic trip assembly had been changed from a 40 amp breaker to this 63 amp contact assembly and in this process, pin 3 misaligned and damaged. With a damaged trip pin on pole three, a higher current was required to trip the breaker instantaneously. When the breaker was tested at the 125% (200 amp) point, trip pin 3 failed to contact the trip bar and the sustained current caused the breaker to overheat and melt.

For the Westinghouse HFB31550 molded case circuit breakers, no instantaneous trip occurred after the breakers were maintained at 125% of the upper magnetic threshold at the low setting of the magnetic adjustment, 562 amps, for greater than 70 seconds. The instantaneous trip current was 851, 959 and 729 amps for poles 1,2 and 3, respectively for one HFB and 2870, 3500 and 2900 for poles 1.2 and 3, respectively for the other HFB breaker. Testing was stopped after 316 seconds at 562 amps (125%) when the cables on the test set melted. The circuit breaker temperature was 341°F.

A root cause failure analysis of molded case circuit breaker Westinghouse HFB31550 was performed. The root cause was determined to be a missing spring on pole 1 of the instantaneous trip mechanism. The armature in the instantaneous trip assembly for each pole normally contains two springs, Figure 3-67. Only one spring was found on the armature of pole 1. With only one spring, the armature assembly was twisted and higher current was required to trip the breaker. The root cause for the other breaker's out of specification condition was indeterminate.

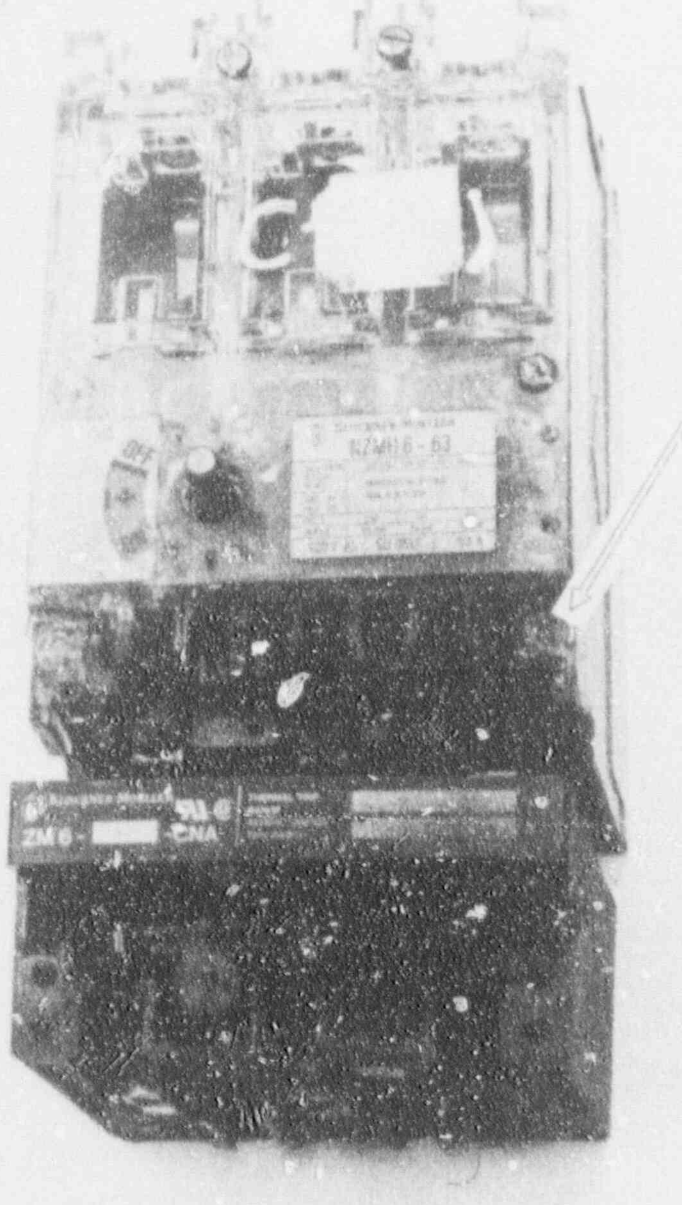


Figure 3-65. Melted Pole 3 of Klockner-Moeller
NZMH6-40 Molded Case Circuit Breaker

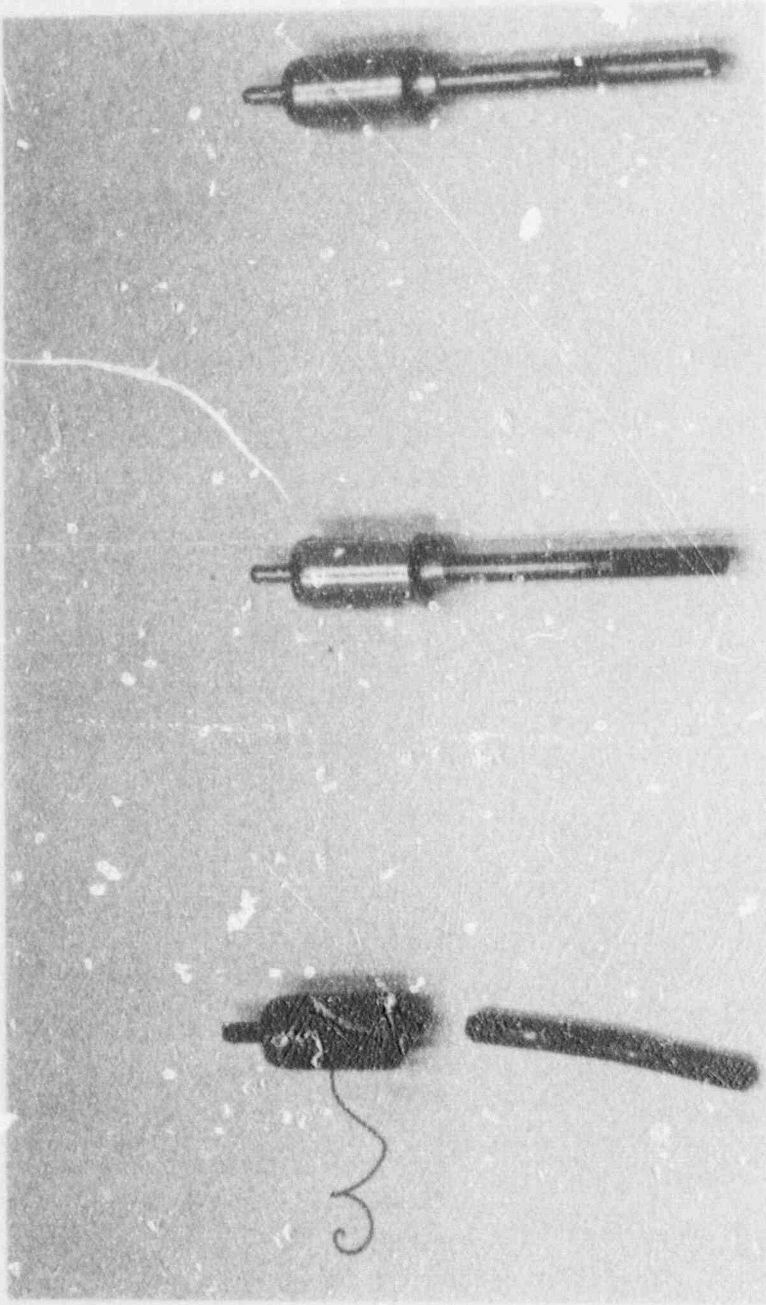


Figure 3-66. Root Cause Failure Analysis of Thermal and Magnetic Trip Assembly of Klockner-Moeller NZMH6-40, Showing Bent and Sheared Trip Pin on Pole 3 Compared to Trip Pins for Poles 1 and 2

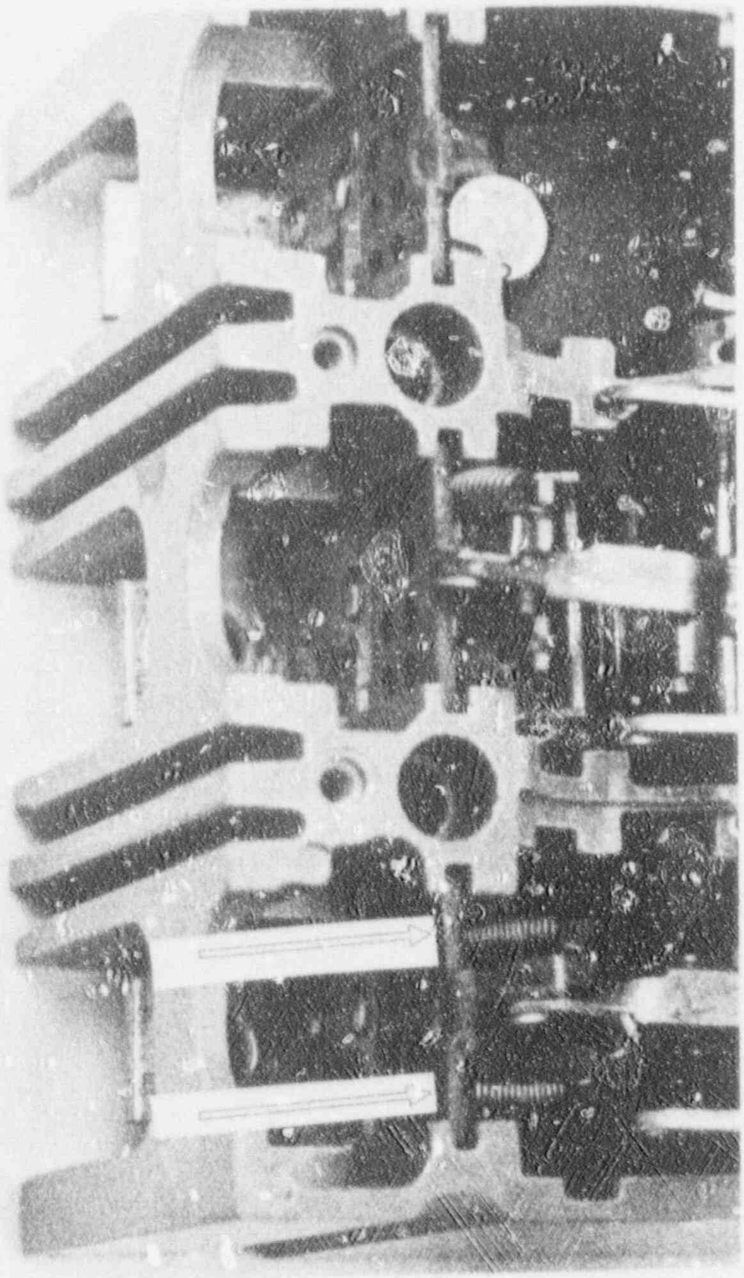


Figure 3-67. Typical Two Springs on Pole 1 of a Westinghouse HFB 31550 Molded Case Circuit Breaker

The instantaneous trip method showed significant differences among the molded case circuit breakers. Aging, heat, inadequate maintenance and a manufacturing defect caused four out of the eleven molded case breakers to exceed the manufacturer's specifications. In each instance the failure of the molded case circuit breaker was in a non-conservative manner.

Dielectric

Dielectric strength was measured four times at 1760 volts: between line and load terminals with the circuit breaker open; between poles with the breaker closed; between all poles and ground with the breaker open and between all poles and ground with the breaker closed. The minimum and maximum leakage currents were 29.5 and 115 microamps for all breakers except for the ITE KMB2F800 which had a leakage current of 220 microamps from line to line with the breaker closed. The dielectric strength differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Infrared Pyrometry

The maximum temperatures measured for the molded case circuit breakers are shown in Figure 3-68. Additionally, the temperatures of 584°F and 341°F were recorded on the Klockner-Moeller NZMH6-40 and Westinghouse HFB 31550, respectively, when they failed to trip during the instantaneous trip method.

Infrared pyrometry did not show significant differences among the devices at 100% rated current.

Temperatures were also measured during the 135% rated current test, 300% overcurrent and 600% overload test. For the 135% rated current test, temperatures averaged 6°F hotter than the 100% rated current test. For the 300% overcurrent tests and 600% overload tests, the temperatures of the molded case circuit breakers were less than the temperatures during the 100% rated current tests.

Infrared Scanning

The scanner showed the maximum temperatures, Figure 3-68, to be hotter than the pyrometer for all eight circuit breakers measured. No trend with age was noted with the scanner although the highest temperatures were measured on one of the 30 year breakers.

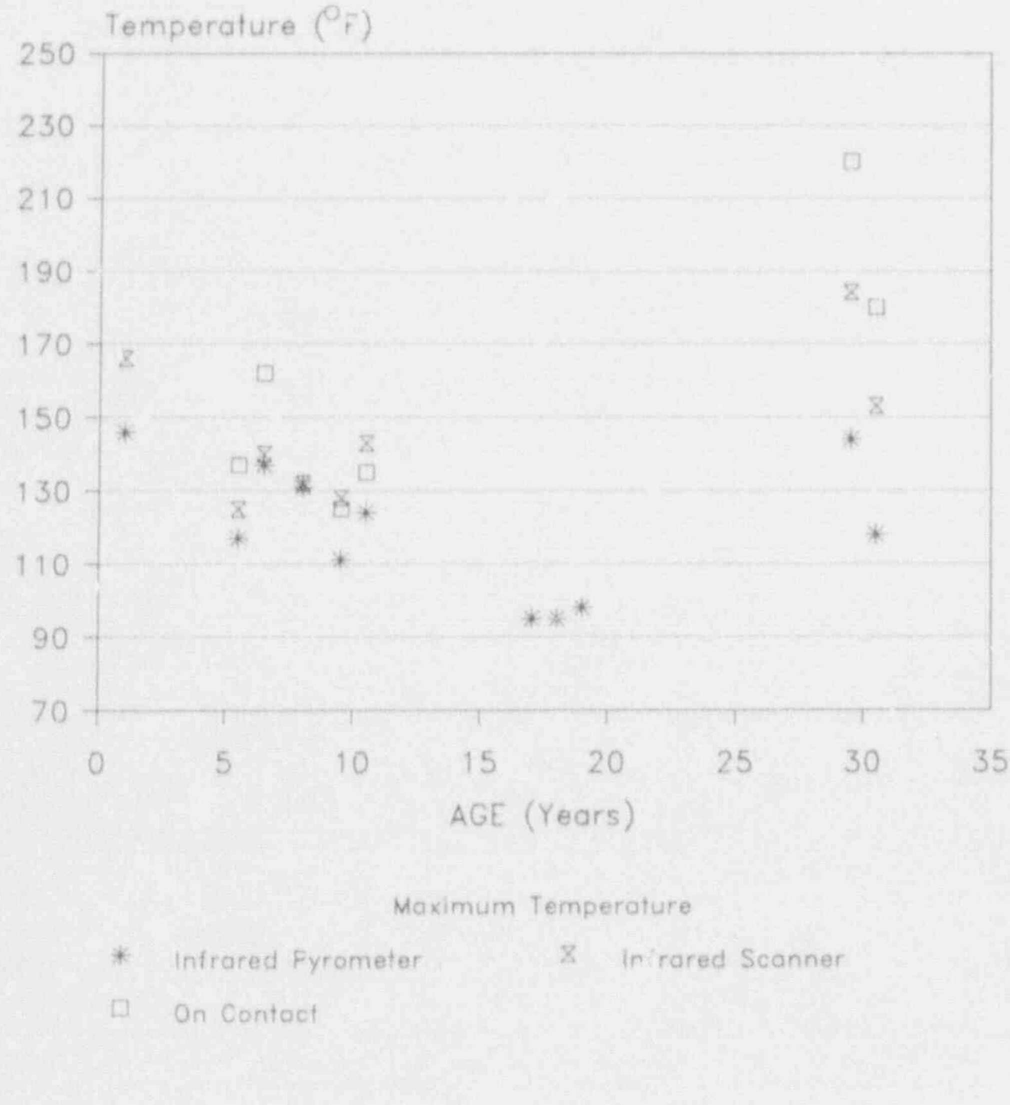


Figure 3-68. Temperature Comparison Molded Case Circuit Breakers at 100% Rated Current

On-contact Temperature

The maximum temperatures obtained are shown in Figure 3-68. The on-contact method pinpoints a spot, therefore the poles were hotter and caused the on-contact method to record the highest temperature on four of the six circuit breakers measured by this method. The on-contact method does indicate a trend towards increased temperatures with age.

Vibration Testing and Acoustic Testing

Vibration signatures were obtained during manual actuation and the 125% instantaneous current tests. The vibration signatures were repeatable for each breaker and did not change significantly between manual actuation and the 125% trip test. Differences were noted among the different molded case circuit breakers, with only the two Klockner-Moeller NZMH breakers having similar vibration signatures. Since the specimens were diverse, the differences in the vibration signatures could not be attributed to age but were a reflection of the different breaker styles and their trip mechanisms.

Acoustic signature differences were noted among the molded case circuit breakers but the diversity of the breakers precludes comparison of the acoustic signatures.

Ion detection

Two ionization smoke detectors were mounted adjacent to each specimen during some of the above tests which required energization of the specimens. The detectors never alarmed even though smoke was present and visible. The lack of ionization detector actuation was determined to be caused from lack of sufficient concentration of the smoke in the area of the detectors. The long lengths of cable, 4 foot between specimen and current source and 8 foot between poles, resulted in smoke coming from the cables not necessarily near the ionization detectors. The temperatures achieved when some of the components failed, were sufficient to damage cable and insulations on some of the molded case circuit breakers.

The lack of ion detector alarm, when the molded case circuit breakers operated properly, indicates that no significant concentration of ionized particles had outgassed from the specimens due to age.

3.7 Metal Clad Circuit Breakers

Two metal clad circuit breakers representing two manufacturers were evaluated in this study. These devices were safety-related metal clad circuit breakers. The specimens were a Westinghouse DB-25 that was 25 years old and a General Electric AK-2S-25-M, which was 29 years old.

The most significant findings on the metal clad circuit breakers were:

- One pole of the General Electric AK-2S-25-M did not trip during the long time delay overcurrent method because of binding in the dashpot of the EC-1 trip device, there was evidence of overheating,

- The other pole of the General Electric AK-2S-25-M tripped without a delay during the long and short time delay overcurrent methods because the oil in the dashpot had leaked out and dried up,

- Vibration signatures were useful at detecting and analyzing the problems with the overcurrent trip devices.

Thirteen ISM techniques were evaluated on the metal clad circuit breakers. They were visual inspection, pole resistance, insulation resistance, long time delay overcurrent, short time delay overcurrent, mechanical actuation, instantaneous trip, infrared pyrometry, infrared scanning, on-contact temperature, vibration testing, acoustic testing, and ion detection.

The following results were obtained from the circuit breakers in the condition in which they were received for this effort.

<u>Visual Inspection and Mechanical Actuation</u>

The Westinghouse DB-25 was a three pole 600 VAC / 250 VDC, 600 amp frame metal clad circuit breaker, with interrupting capacity of 25,000 amps. The circuit breaker was equipped with two auxiliary devices, an undervoltage attachment and a closing coil. The center arc chute had a broken ceramic side plate. Discoloration and metal deposits were visible on the inside of all of the arc chutes. The main and arcing contact surfaces were pitted and oxidized. The connecting stabs in the back of the circuit breaker were oxidized. The unit was dirty and the outer jacket of some of the wire insulation had split. The left side of the carriage trip mechanism was slightly bent. There were no signs of overheating on the closing coil or shunt trip coil. The overcurrent trip devices on each phase were found to be set at a time delay of 20 seconds at a current of 1125 amps, a long time delay pick-up at 270 amps and an instantaneous pick-up at 1800 amps.

The mechanical actuation was verified by removing and inspecting the arc chutes and manually closing the breaker, slowly, using the solenoid mechanism. A print of the contacts was made by inserting paper between the moving and fixed contacts and closing the breaker. The prints showed that the moving contacts on phases B and C were slightly misaligned to the right of the fixed contacts. The contact closing sequence was C, B, A. Contact travel was measured to be 1.25 inches on all three contacts. The moving contact operating shaft was removed and inspected. No lubricant was on the operating shaft and little lubricant was on the closing mechanism. The breaker could not be manually closed. Since the operating handle was missing, attempts were made to manually close by operating the shaft. The closing mechanism had significant friction and did not fully close. A part was missing so that the manual trip button did not function.

The General Electric AK-2S-25-M was a two pole 600 VAC / 250 VDC, 600 amp frame metal clad circuit breaker with interrupting capacity of 25,000 amps. The circuit breaker was equipped with two EC-1 Series Overcurrent Trip Devices. The long time delay setting was found to be 250 amps and the short time delay setting was 2500 amps. The circuit breaker was missing one moving contact. Another was added for testing. The connections on the back of the circuit breaker were oxidized. Lubricant was visible and appeared satisfactory.

The mechanical actuation was verified by removing and inspecting the arc chutes and manually closing the breaker. The breaker was manually reset, closed and tripped. It operated with no binding. Paper was inserted between the moving and fixed contacts and a pattern of the contacts was obtained while manually closing the breaker. The contact pattern showed that the contacts were closing properly and that all four points of contact were in proper alignment. The contact gap was 1.65 inches and the contact wipe was 3/32 of an inch. The movement of the trip arm on the EC-1 trip device was verified to be unrestricted, have a short air gap prior to engaging the trip paddle and have sufficient movement after the breaker had tripped. The short time delay armature of both EC-1 trip devices was actuated by inserting a pin in the access hole and the armature was pushed against the magnet. The movement was unrestricted and overtravel after engagement of the trip arm and trip paddle was adequate. The actuation of the long time delay armature for both devices was also attempted by inserting a pin into the access hole. For one EC-1 trip device, the armature would not move. For the other EC-1, there was no restriction and the armature moved with little force, when there should have been some resistance from the dashpot. Because the EC-

1 has a phenolic cover, the dashpot is not visible when the EC-1 is installed on the breaker.

Pole resistance

The highest resistances measured for the poles of each circuit breaker were 0.254 and 0.212 mohms for the Westinghouse DB 25 and General Electric AK-2S-25-M, respectively. There was little difference in pole resistance in spite of the dirty appearance of the DB-25. No trend with age and no correlation with significant results of other ISM methods were found.

Insulation resistance

Insulation resistance was measured four times: between line and load terminals with the circuit breaker open; between poles with the breaker closed; between all line poles and ground with the breaker open and between all load poles and ground with the breaker open. The minimum resistance was 1.7 E8 ohms and insulation resistance differences were not significant. No trend with age and no correlation with significant results of other ISM methods were found.

Long Time Delay Overcurrent

The long time delay overcurrent trip times for each pole are as follows. For the DB-25 breaker, the trip device for each pole was set at 20 seconds. The trip times varied from 22 to 30 seconds, which was 110% to 150% of the setting. The manufacturer's specification was 15 to 33 seconds.

For the AK-2S-25-M breaker, one pole was tested for over 426 seconds and never tripped. Smoke was visible from the area around the arc chutes. The other pole tripped in 5.69 seconds while at rated current and therefore three times the setting was not attempted. The long time delay overcurrent function was accomplished by the EC-1 Series Overcurrent Tripping Device. Root cause failure analyses of the EC-1 tripping devices were performed to determine the cause for the significant differences in trip characteristics. The root cause of the failure to trip on long time delay was caused by binding in the dash pot. The dash pot was bound and the dash pot arm would not move. The dash pot was full of oil and appeared to have been overheated since the metal in contact with the gasket had discolored the seal area, Figure 3-69. Additionally, the coil insulation had been overheated as noted by its black color.

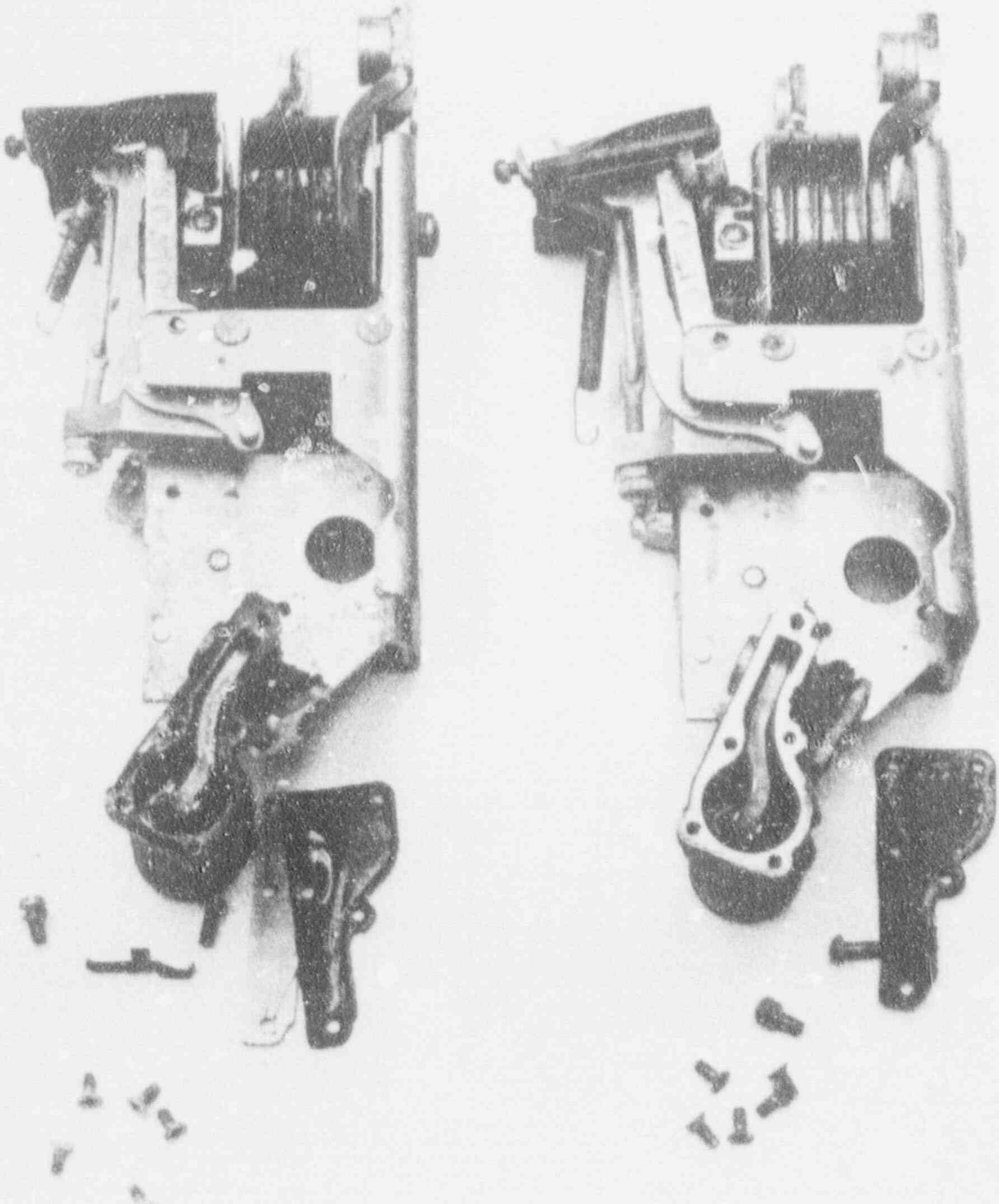


Figure 3-69. General Electric EC-1 Series
Overcurrent Tripping Devices
(Left Device Failed to Trip;
Right Device had No Long Time Delay)

The root cause of the failure of the EC-1 tripping device, which was tripping below specification on 100% rated current was a loss of oil. The FC-1 was removed from the breaker and the cover removed. The dashpot was opened and found to be almost out of oil. Figure 3-70 shows the outside of the dashpot where there was oil and dust visible on the outside. In Figure 3-69, the lack of oil is noticeable, when compared to the other EC-1 tripping device.

Short Time Delay Overcurrent

The GE AK-2S-25-M metal clad circuit breaker had a short time delay function which was also part of the EC-1 series overcurrent tripping device. This test was performed by using a high current test set at a current equal to 100% of the short time delay current setting to each pole of the General Electric AK-2S-25-M. One pole tripped at 0.04 seconds and the other pole tripped at 67.3 seconds. The acceptance criteria was 0.8 to 70 seconds at the test current. A root cause failure analysis was performed to determine the cause of the EC-1 device to trip at lower than the specification. The root cause was the loss of oil in the dashpot for the long time delay overcurrent trip mechanism which was tripping the unit before the short time delay could operate. Thus the test was detecting the operation of the defective long time delay overcurrent trip function.

A root cause failure analysis of the other EC-1, which was causing the short time delay overcurrent trip time to be near the manufacturer's upper limit, was performed. The root cause of this problem was overheating caused by the failure of the long time delay overcurrent trip function. When the dashpot arm was stuck during the long time delay overcurrent test, current overheated the coil and caused the short time delay function to approach the upper limit of the manufacturer's specification.

Instantaneous Trip

The Westinghouse DB-25 had an instantaneous trip function. The currents causing an instantaneous trip were 2790, 2780 and 2730 Amps for the three phases. These were within the manufacturer's specifications. No trend with age and no correlation with significant results of other ISM techniques were found.

Infrared Thermal Pyrometry

The maximum temperatures were measured for the metal clad circuit breakers. The undervoltage coil on the Westinghouse DB-25 circuit breaker was much hotter than the current carrying parts of

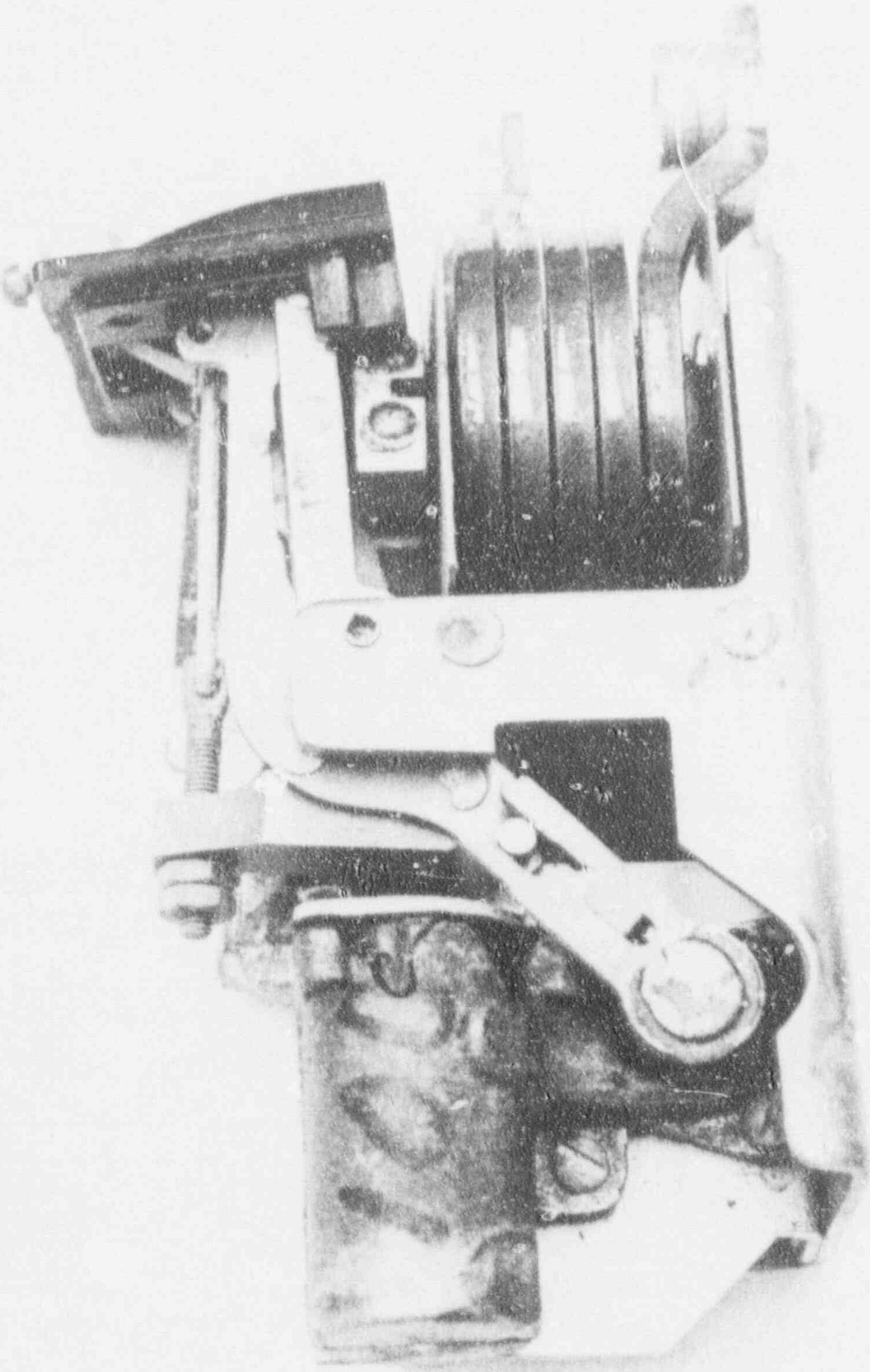


Figure 3-70. General Electric EC-1 Series
Overcurrent Tripping Device
Note Evidence of Oil Leakage and Dirt on Side of Dashpot

either circuit breaker and measured 187°F. The trip units were at room ambient conditions and the main contacts approximately 15°F hotter at 87°F.

For the GE AK-2S-25-M breaker, the maximum temperature was 115°F on the trip unit. The main contacts were 9°F hotter than ambient. No trend with age and no correlation with significant results of other ISM techniques were found.

Infrared Scanning

The scanner showed the maximum temperatures to be the same as the pyrometer, for all points measured. No trend with age was noted with the scanner.

On-contact Temperature

The on-contact method pinpoints a spot, therefore the coil of the GE AK-2S-25-M was slightly hotter than the temperature measured with the infrared systems. No trend with age was noted with the on-contact method.

Vibration Testing and Acoustic Testing

Vibration signatures were obtained during manual actuation, the long time delay and short time delay overcurrent tests. The vibration signatures were repeatable for each breaker. Differences were noted between the metal clad circuit breakers. The vibration signatures were analyzed in the frequency domain, Figure 3-71. The specimens had different trip mechanisms and therefore the differences in the vibration signatures could not solely, be attributed to age but were a reflection of the different breaker styles and their trip mechanisms.

The main vibration signature was caused by the tripping of the main contacts. The vibration signature was continuously monitored, before and during the manual actuation, the long time delay and short time delay overcurrent tests. When the vibration exceeded a trigger level, caused by the main breaker trip, the vibration signature and a set portion of the signature prior to the trip were captured and stored. The portion of the signature prior to the trigger event was known as pre-trigger. Figure 3-72 shows the time history of the vibration signature for the GE AK-2S-25-M, from a short time delay overcurrent trip on pole 1. The main vibration starts at approximately 18 milliseconds and lasts for approximately 30 milliseconds. The pre-trigger portion, prior to 18

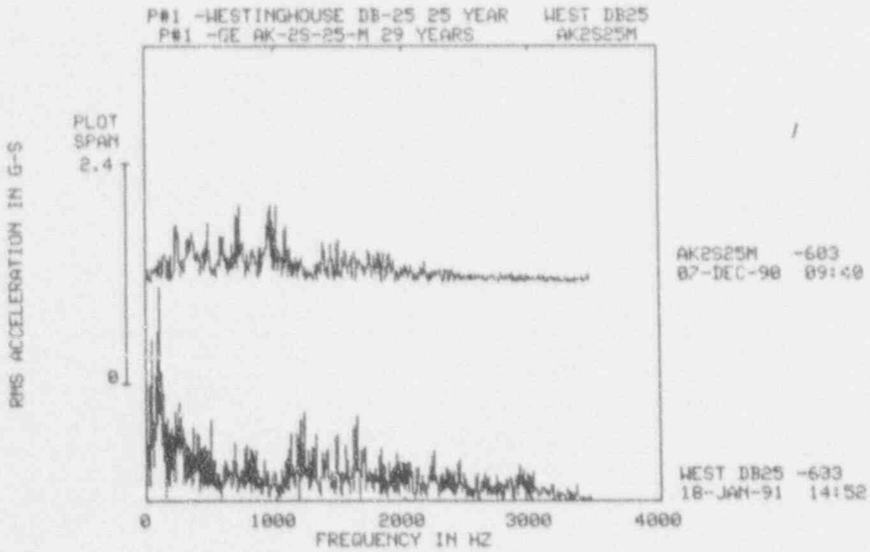


Figure 3-71. Vibration Signatures of
Metal Clad Circuit Breakers

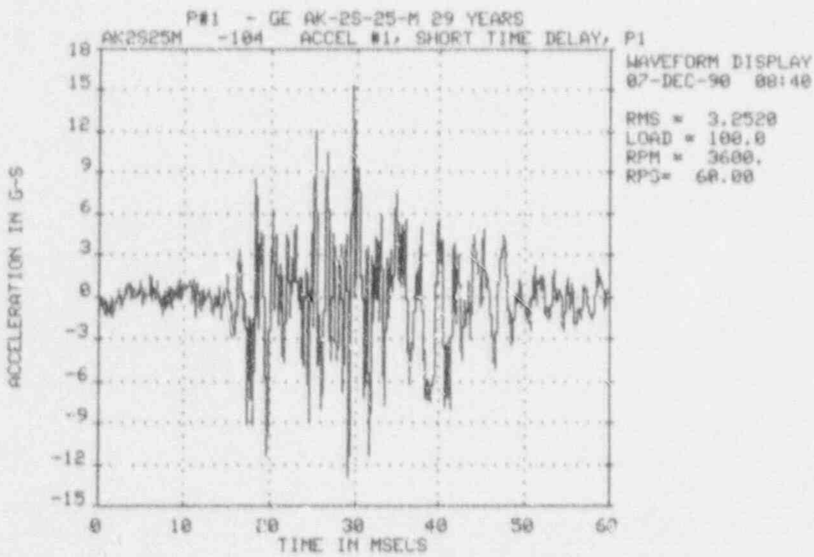


Figure 3-72. Vibration Time History Signature of GE AK-2S-25-M Metal Clad Circuit Breaker

milliseconds, of the time history signature contained the information on the initiating vibration from the short time delay function for the EC-1 trip device.

Analyses of the vibration signature time histories for the initiating events of manual trip, short time delay overcurrent trip and long time delay overcurrent trip were performed for the pole 1 and pole 2 EC-1 trip devices. Significant differences were noted among the three initiating events and between the performance of the EC-1 trip devices on each pole. Figure 3-73 shows the difference between the EC-1 trip devices on pole 1 and pole 2 for the short time delay overcurrent trip. The higher pre-trigger vibrations noted in pole 2 were caused from the defective long time delay overcurrent trip function of the EC-1 on pole 2 which was out of oil and therefore not providing any delay. The analysis of the vibration signature correlated with the time characteristic information obtained from the short time delay overcurrent method to show that the EC-1 on pole 2 was defective.

The vibration testing method was effective at determining differences caused by age. This was particularly evident in the vibration signature differences between the performance of the 29 year old EC-1 trip devices of pole 1 and pole 2 on the GE AK-2S-25-M metal clad circuit breaker.

Acoustic signature differences were noted among the metal clad circuit breakers but the diversity of the breakers precludes comparison of the acoustic signatures.

Ion detection

Two ionization smoke detectors were mounted adjacent to each specimen during some of the above tests which required energization of the specimens. The detectors never alarmed, even though smoke was visible on the GE AK-2S-25-M metal clad circuit breaker during the long time delay overcurrent test. The cause of the non-actuation of the ion detector was due to an insufficient concentration of smoke in the area of the detector. Even though the detector was located directly above the breaker, since it was tested outside of a panel, air currents caused a lack of concentration of the smoke at the detector.

The lack of ion detector alarm, when the metal clad circuit breakers operated properly, indicates that no significant concentration of ionized particles had outgassed from the specimens due to age.

1

IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

1

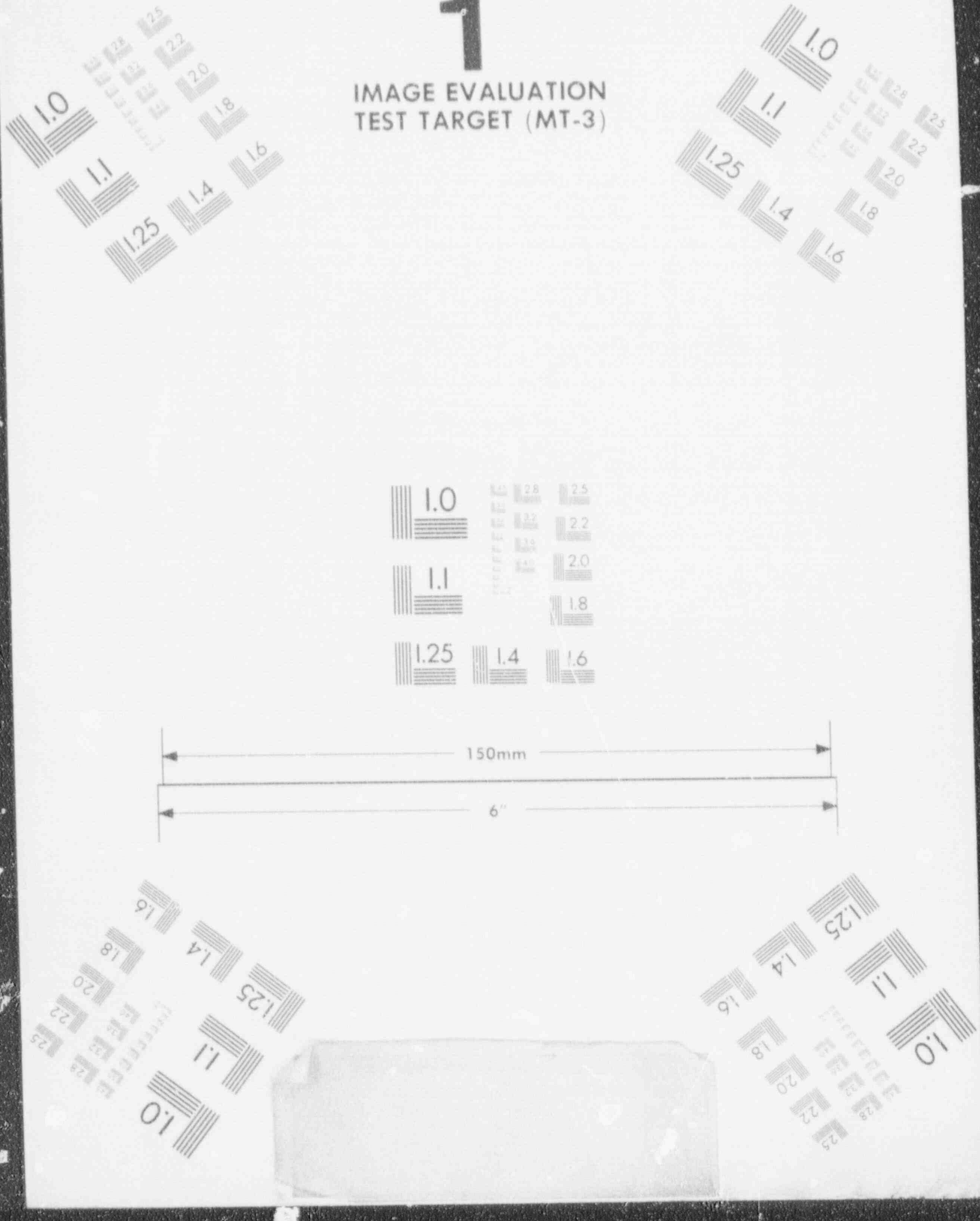
IMAGE EVALUATION TEST TARGET (MT-3)

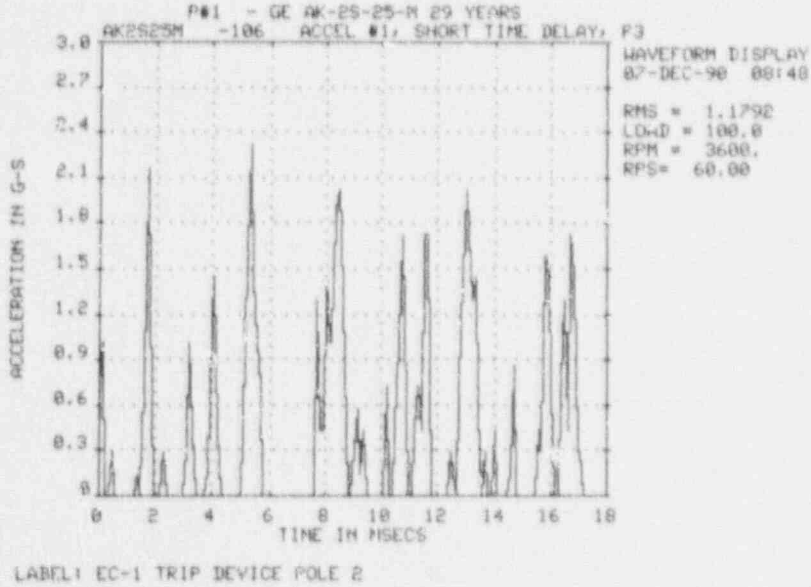
150mm

6"

1

IMAGE EVALUATION TEST TARGET (MT-3)





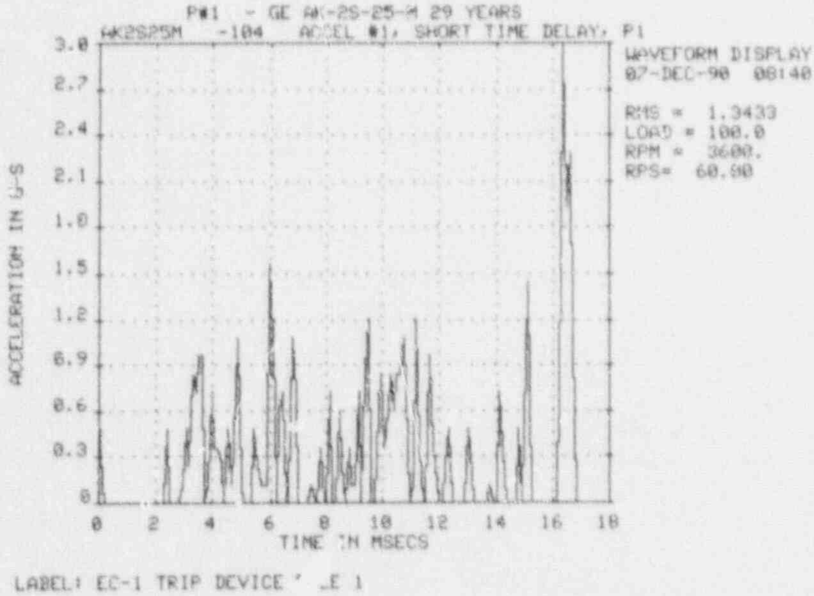


Figure 3-73. Vibration Time History Comparison of EC-1 Trip Devices on Pole 1 and Pole 2

4. EVALUATIONS OF DEGRADED CONDITIONS AND INSITU EFFORTS

Specimens of each of the relay and circuit breaker types were purposely degraded and the ISM methods performed after each degraded condition. These tests allowed evaluations of the effectiveness of each ISM method to detect and / or predict the level of the degradation. Quantifiable parameters of the extent of degradation were also possible in many instances. Each degradation was purposely severe and simulated typical failure mode conditions, but did not cause total loss of operability. The degraded conditions performed on each device were chosen based on the information from Phase I, NRC Information Notices, Bulletins and Generic Letters and from the research team's previous experience. The degraded conditions were performed based on the failure modes unique to each style of relay and circuit breaker. Thus the manner in which a degraded condition was achieved and number of degraded conditions was different depending on each device's characteristics. This resulted in at least five common types of degraded conditions being performed on each relay, with additional degraded conditions being performed on some of the relays and circuit breakers. The common degraded conditions were contact damage, dirt accumulation, loose connections, overheated and high potential test. The results of the degraded conditions testing are provided in the following by device type.

4.1 Results of Degraded Conditions on Protective Relays

The 10 year old General Electric and a 30 year old Westinghouse protective relays were subjected to five degraded conditions and the ISM methods performed after each degraded condition.

The most significant findings on the protective relays were:

- o Visual inspection was effective at detecting 80% of the degraded conditions,
- o Induction unit pick-up was effective at detecting 80% of the degraded conditions for the Westinghouse relay but only 20% for the GE relay,
- o Infrared Thermography was effective at detecting 40% and 80% of the degraded conditions in the Westinghouse and GE relays, respectively,
- o Loose connections in the GE relay caused temperature increases of $63^{O}F$, which would reduce expected life to 6% of original expected life

- o The significant temperature increases were best observed with the front cover off and by viewing at 45° from normal,

- o The target and seal-in method was effective at detecting 40% of the degraded conditions for the Westinghouse relay but detected none of the degraded conditions on the GE relay.

The degraded conditions were contact damage, dirt accumulation, overheated, loose connections and high potential tests. The ISM methods of current surge comparison, infrared scanning and on-contact temperature were not performed during these degradation tests on protective relays because the equipment was unavailable at the time the tests were performed.

The ISM methods of insulation resistance, zero check, time / current characteristic, instantaneous trip unit, inrush current, operating current and ion detection did not show any significant change from the original baseline parameters during any of the degradation tests. Figures 4-1 through 4-4 show the results of induction unit timing(time / current characteristic), inrush / operating current and instantaneous trip unit.

The ISM methods which did show significant changes from the original baseline parameters during at least one of the degradation tests were visual inspection, contact resistance, coil resistance, magnetic flux, induction unit pick-up, target and seal-in, infrared pyrometry, vibration testing and acoustic testing. The high potential degradation did not cause significant change in any of the ISM methods.

Visual inspection was effective in four of the five degraded conditions. They were contact damage, dirt accumulation, overheated and loose connections.

Contact resistance changed significantly in one out of the five degraded conditions on the GE relay, Figure 4-5, and was about the same or increased slightly on four out of five degraded conditions on the Westinghouse relay, Figure 4-5. The significant increase in contact resistance was on the GE specimen during the loose connections test. It increased 48% from baseline.

Coil resistance changed significantly in one out of the five degraded conditions on the Westinghouse relay and the GE relay, Figure 4-6. The loose connections test caused an increase of 17% from baseline for the Westinghouse relay. The contact damage, when the induction unit contacts of the GE specimen were soldered

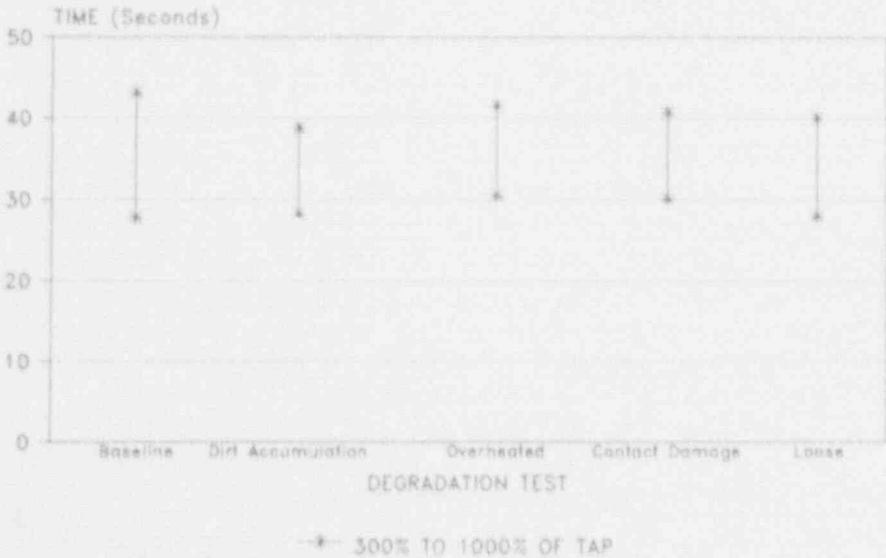


Figure 4-1. Induction Unit Timing
Comparison Protective Relay Westinghouse

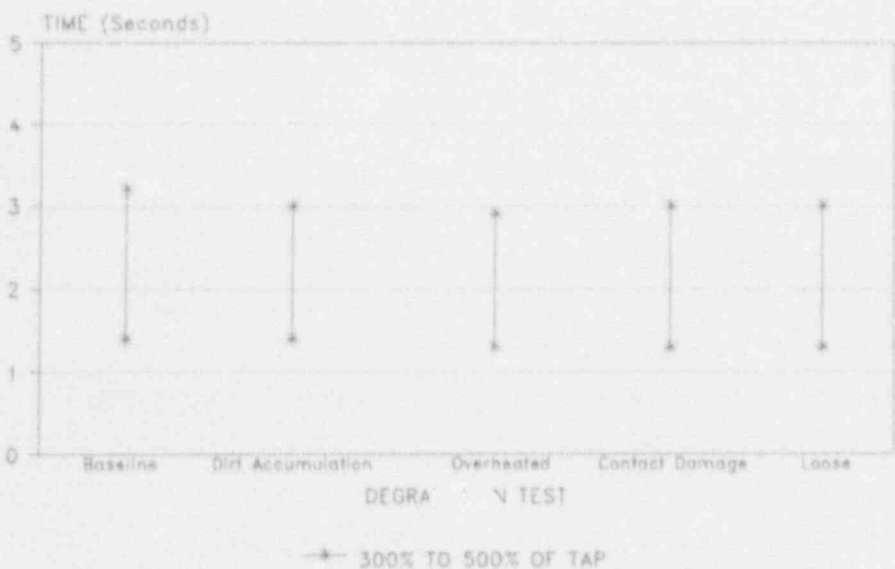


Figure 4-2. Induction Unit Timing
Comparison Protective Relay GE IAC

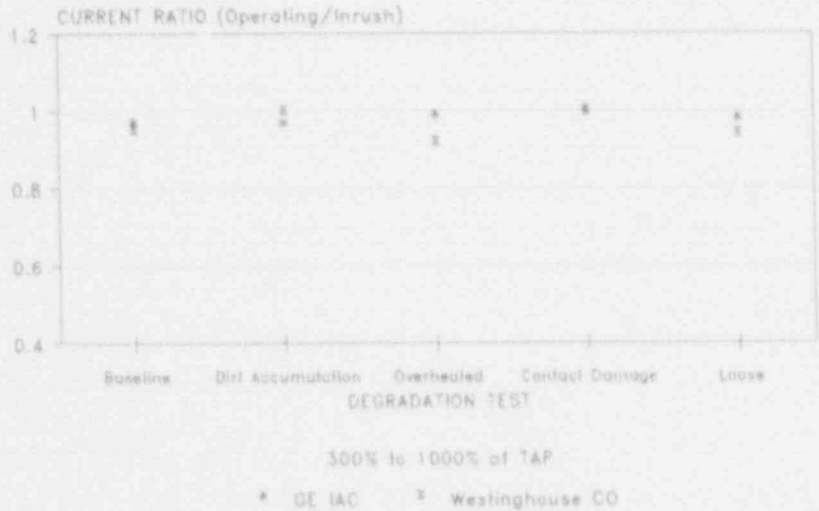


Figure 4-3. Operating/Inrush Current
Comparison Protective Relays

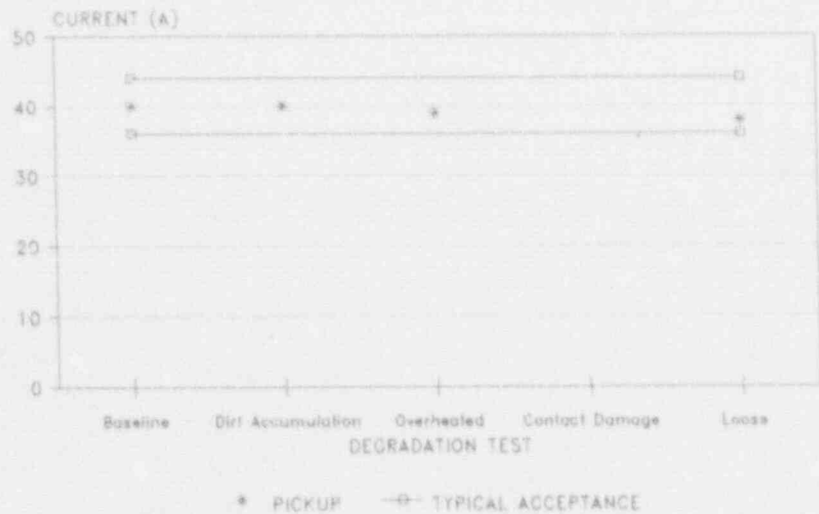


Figure 4-4. Instantaneous Unit Pickup
Comparison Protective Relay GE IAC

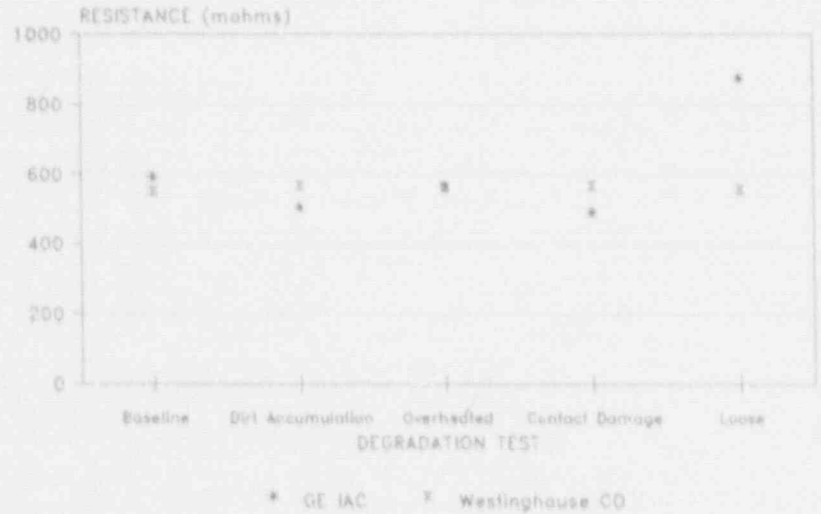


Figure 4-5. Contact Resistance
Comparison Protective Relays

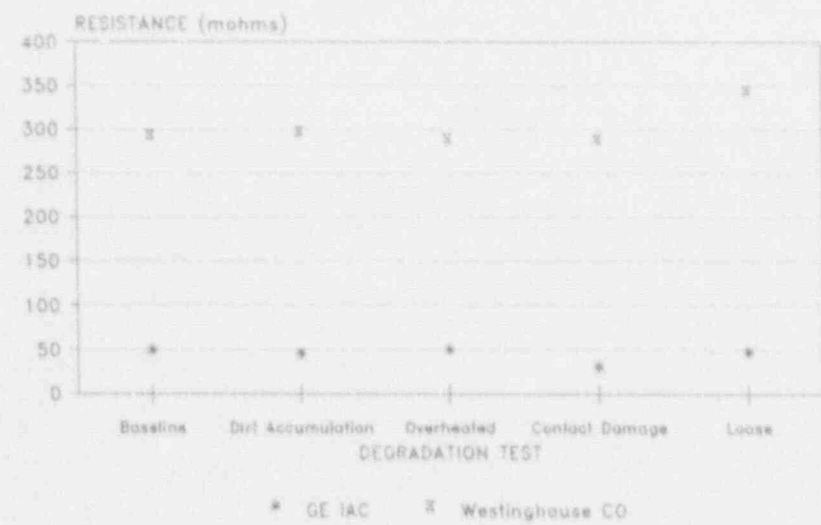


Figure 4-6. Coil Resistance
Comparison Protective Relays

together, resulted in a coil resistance decrease of 37.4% from baseline.

Magnetic flux changed significantly in four of the five degraded conditions. Dirt accumulation, overheated, contact damage and loose connections all caused the flux to decrease or shift for both specimens, Figures 4-7 and 4-8.

Induction unit pick-up changed significantly in four of the five degraded conditions for the Westinghouse relay and one out of five for the GE relay. All degraded conditions except for high potential testing caused the Westinghouse relay to go out of specification. Figure 4-9 shows the pick-up current of the Westinghouse specimen outside of the typical ±5% of nominal tap setting for these devices. The pick-up current increased to 10% during the dirt accumulation test and 7.[illegible] during the overheated test. The pick-up values went the opposite direction during the contact damage and loose connections tests resulting in decreases of 9% and 5.5% respectively.

The GE relay had been out of specification initially for induction unit pick-up. The induction unit pick-up deviation approached or became within specification during the degraded conditions of dirt accumulation, overheated and contact damage. The loose connection degraded condition caused the induction unit pick-up to increase 149% over the baseline value of 4.61 amperes, Figure 4-10.

The target and seal-in method (indicating contactor switch ICS for Westinghouse) changed only on the Westinghouse specimen. Two conditions, dirt accumulation and overheated, caused changes, Figure 4-11. The ICS pick-up values were 320 and 300 milliamperes for the dirt accumulation and overheated tests respectively. These values were below the typical pick-up range which is 75% to 100% of seal-in or ICS tap setting. In contrast, Figure 4-12 shows the target and seal-in to be unaffected in the GE relay by the degraded conditions.

Figure 4-13 shows the Westinghouse relay after overheat and dirt accumulation. This figure attests to the fact that the degraded condition after overheat and dirt accumulation was sufficiently severe as to constitute a worst case.

Infrared pyrometry showed temperature changes in two out of five degraded conditions for the Westinghouse relay and four out of five for the GE relay. Overheat and loose connections caused over 30°F increase in temperatures when viewed with the cover off for the Westinghouse relay, Figure 4-14. Dirt accumulation, contact damage and loose connections caused over 20°F increase in

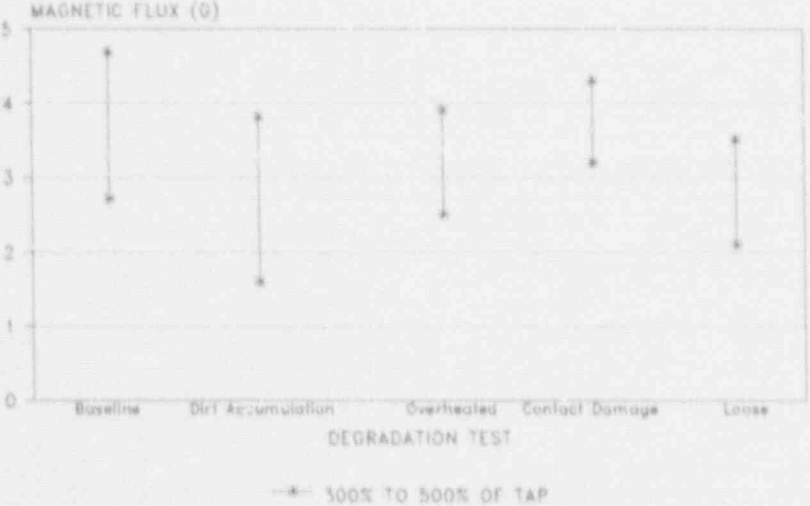


Figure 4-7. Magnetic Field Comparison
Protective Relay GE IAC

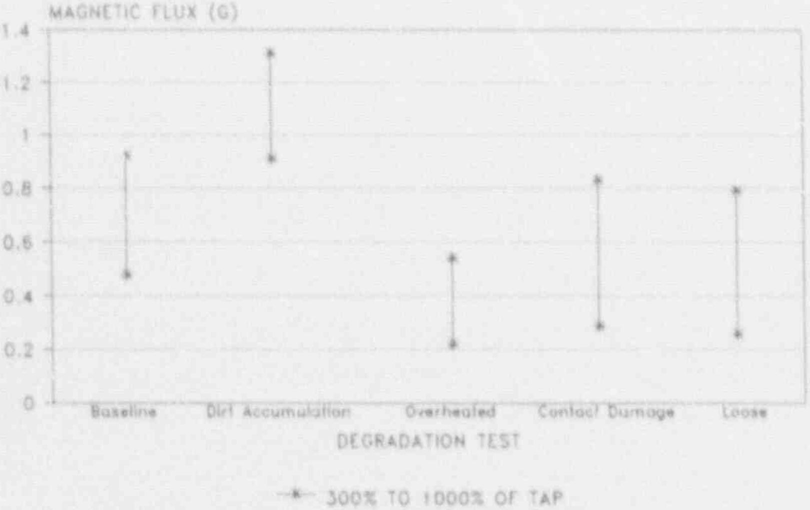


Figure 4-8. Magnetic Field Comparison
Protective Relay Westinghouse

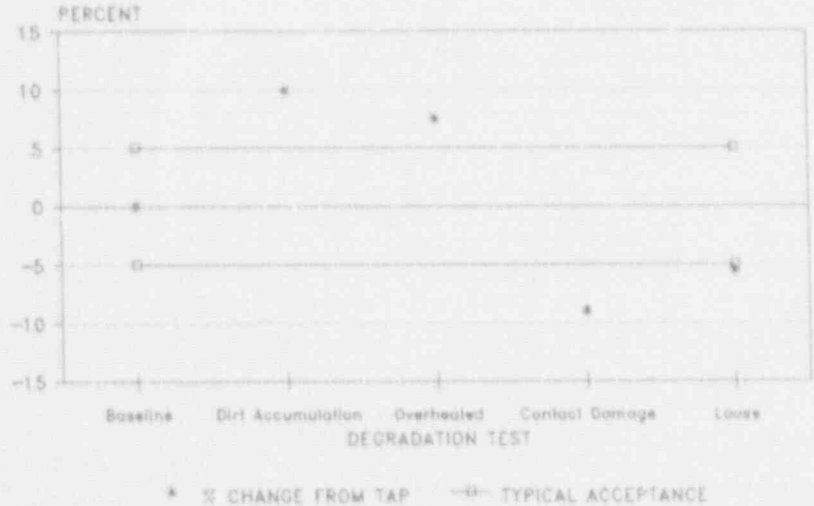


Figure 4-9. Induction Unit Pickup
Comparison Protective Relay Westinghouse

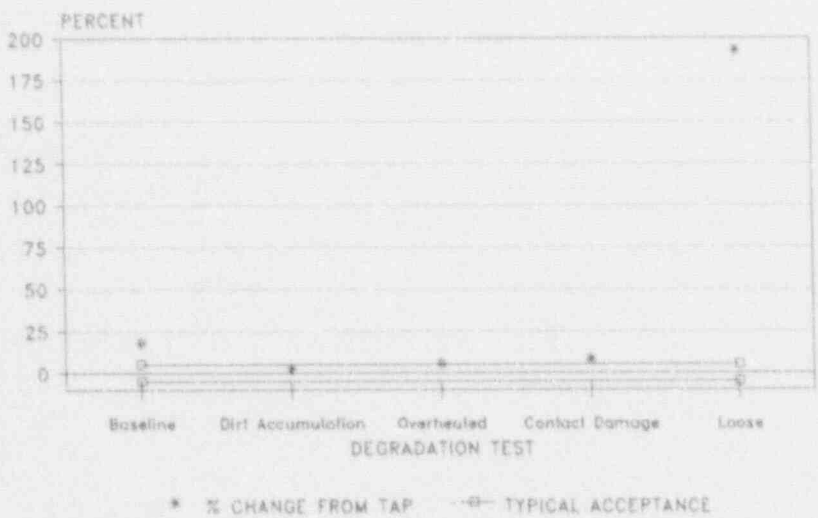


Figure 4-10. Induction Unit Pickup
Comparison Protective Relay GE IAC

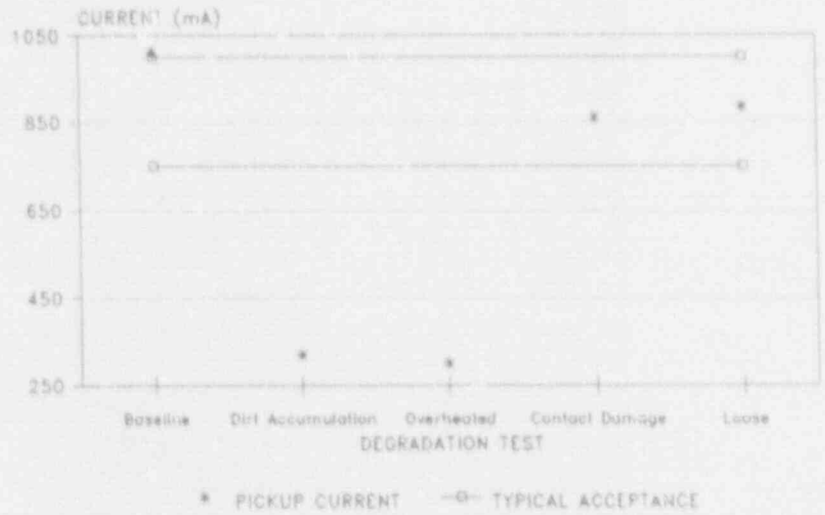


Figure 4-11. ICS Pickup Comparison
Protective Relay Westinghouse

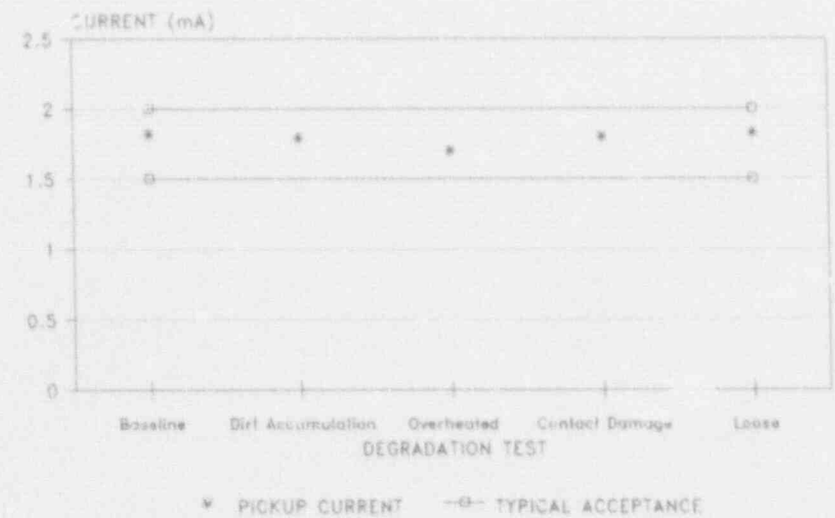


Figure 4-12. Target Seal-In Pickup
Comparison Protective Relay GE IAC

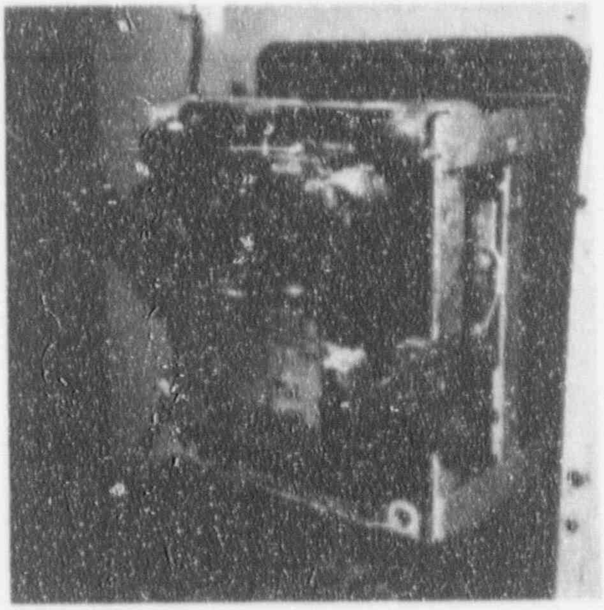


Figure 4-13. Westinghouse Protective Relay After Overheat and Dirt Accumulation Degradation Tests.

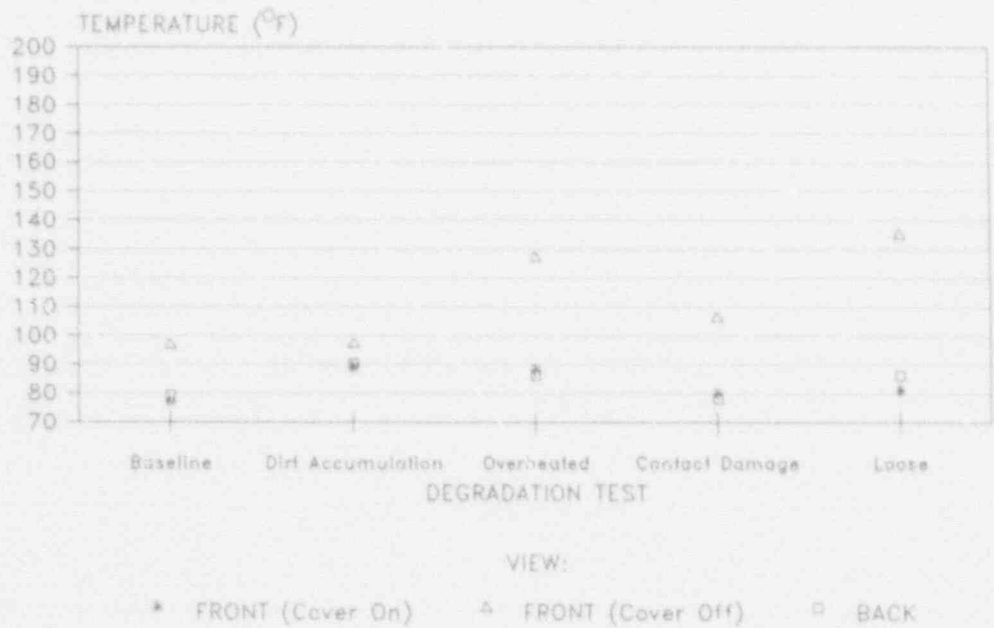


Figure 4-14. Infrared Pyrometry Comparison Protective Relay Westinghouse

temperatures when viewed with the cover off for the GE relay Figure 4-15.

When viewed with the cover on and from the back of the relays, significant variations in temperature were undetectable. The angle of view was also significant for these relays. Figure 4-16 shows that the hottest temperatures were masked in normal 90° view but were detectable when viewed at 45° angles to the right or left of normal.

Vibration signature differences were caused by three of the degraded conditions on the Westinghouse relay. Figure 4-17 shows that loose connections caused a peak at 480 Hz. Overheat caused a peak at 242 Hz and the characteristic peak at 359 Hz decreased to approximately one third by dirt accumulation. Acoustic signature differences were caused by the same three conditions, although not as noticeably. The vibration and acoustic signatures on the GE relay were different but the levels were too low to attribute the changes to the degraded conditions.

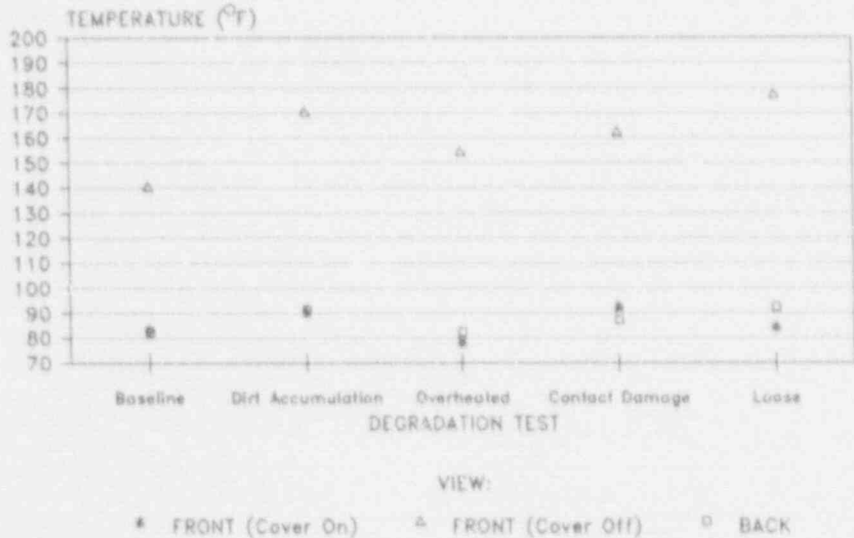


Figure 4-15. Infrared Temperature
Comparison Protective Relay GE IAC

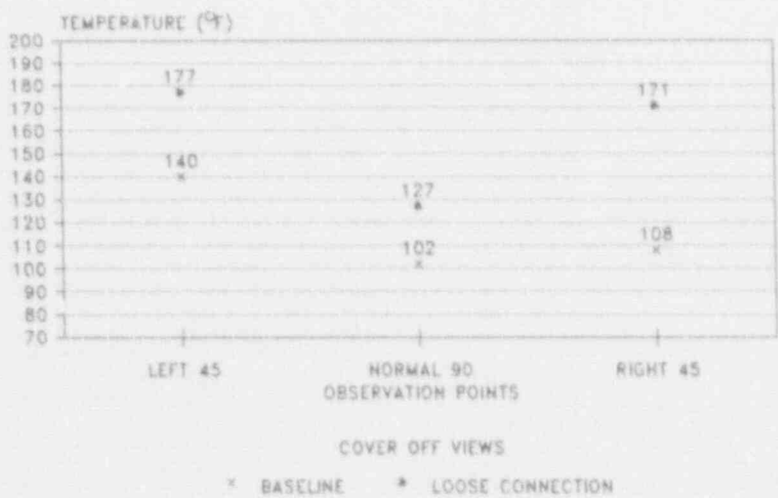


Figure 4-16. Infrared Pyrometry
Comparison Protective Relay GE IAC

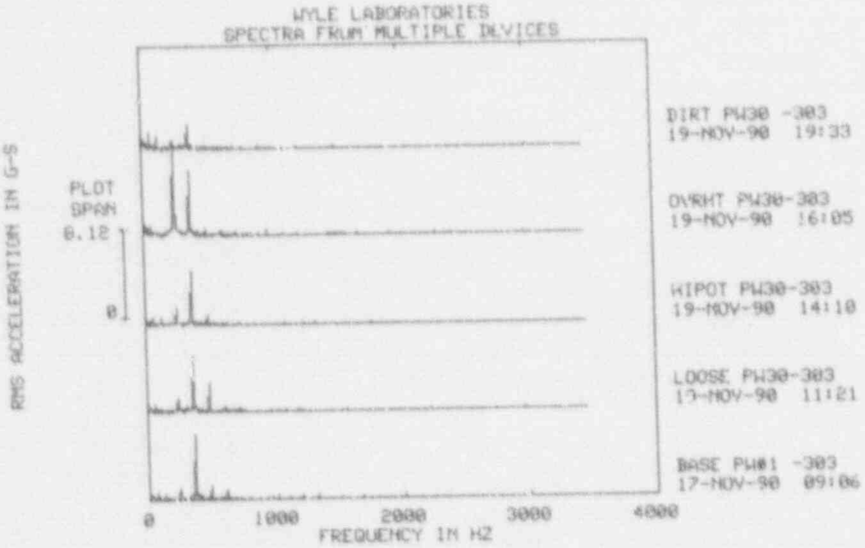


Figure 4-17. Vibration Signature Comparison of Westinghouse Protective Relay Before and After Degraded Conditions

4.2 Results of Degraded Conditions on Control Relay

The new Struthers Dunn control relay was subjected to ten degraded conditions and the ISM methods performed after each degraded condition.

The most significant findings on the protective relays were:

- o Pick-up voltage was insensitive to 90% of the degraded conditions,
- o Insulation resistance and ion detection were insensitive and unchanged by the degraded conditions,
- o Infrared thermography was effective at detecting 40% of the degraded conditions,
- o The degraded conditions detected by infrared thermography were undetected by the current industry practice of pick-up voltage,
- o Each of the degraded conditions detected by infrared thermography result in shortened relay life due to increased temperatures. The increased temperatures would result in a life expectancy of less than one fourth of the original expected life,
- o Significant temperature increases were caused by the degraded conditions of loose connections, overheated, dirt accumulation and shorted coil turns,
- o Vibration signatures were sensitive to 70% of the degraded conditions.

The degraded conditions were low contact current, contact damage, contact to contact resistance, blocked armature, shorted coil turns, dirt accumulation, overheated, increased coil resistance, loose connections and high potential tests. The ISM methods of current surge comparison, infrared scanning and on-contact temperature were not performed during these degradation tests on protective relays because the equipment was unavailable at the time the tests were performed.

The ISM methods of insulation resistance and ion detection did not show any significant change from original baseline parameters during any of the degradation tests. The ISM methods which did show significant change from the original baseline parameters during at least one of the degradation tests were visual inspection, contact and coil resistance, magnetic flux, pick-up voltage, drop out voltage, inrush current, holding current, infrared pyrometry, vibration testing and acoustic testing. The high potential degradation did not cause significant change in any of the ISM methods.

Visual inspection was effective in five of the ten degraded conditions. They were blocked armature, contact damage, dirt accumulation, overheated and loose connections.

Contact resistance changed significantly in four out of the ten degraded conditions. Figure 4-18 shows the range of contact resistances for each contact set after each of the degraded conditions. Additionally, the contact resistance increased the most, to a peak of 995 mohms during the blocked armature degradation since the contacts did not fully close.

Coil resistance changed significantly in one out of the ten degraded conditions. Shorted turns caused a 60 % drop in coil resistance, Figure 4-19.

Magnetic flux changed significantly in five of the ten degraded conditions. Dirt accumulation, overheated, shorted coil turns and blocked armature all caused the magnetic flux to decrease and contact damage caused an increase, Figure 4-20.

Pick-up voltage increased in only one of the ten degraded conditions and decreased in three others. The decrease in pick-up voltage would normally be misinterpreted as an improvement, but since the relays were actually degraded, this is shown to be misleading. Blocked armature caused pick-up voltage to increase and dirt accumulation, overheated and shorted coil turns caused decreases in pick-up voltage, Figure 4-21. Blocked armature caused the pick-up voltage to exceed the specification.

Drop out voltage changed in two of the ten degraded conditions, Figure 4-22. Contact damage of a welded contact caused the drop out to increase since the moving contact bar is directly connected to the armature. Shorted coil turns caused a decrease in drop out voltage.

Inrush and holding current changed in one out of ten degraded conditions. Shorted coil turns caused an increase of over 200% for both inrush and holding current, Figure 4-23 and 4-24.

Infrared pyrometry showed temperature changes in four out of ten degraded conditions, Figure 4-25. The adverse effects of all four conditions were undetected by the pick-up voltage method. Loose connections and overheated caused an increase in maximum

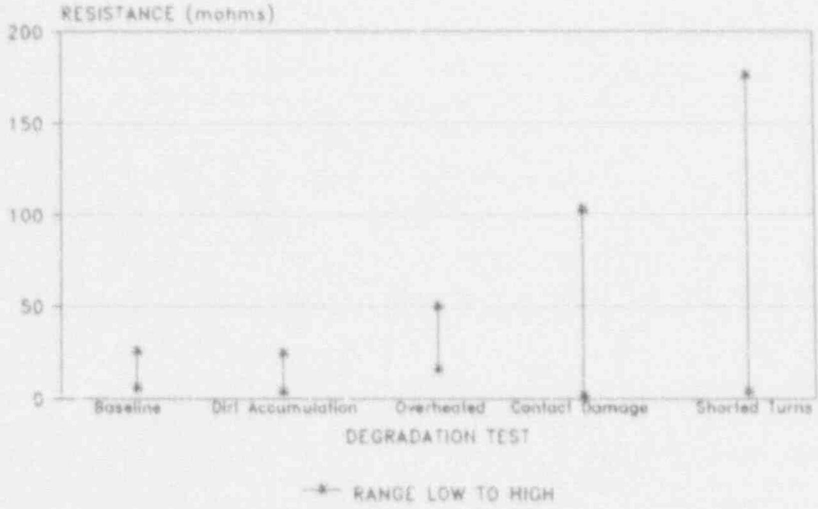


Figure 4-18. Contact Resistance
Comparison Control Relay SD219

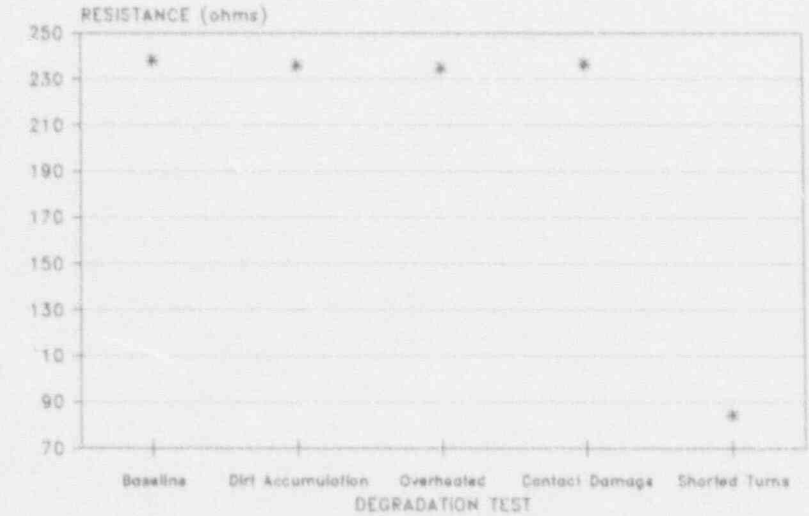


Figure 4-19. Coil Resistance
Comparison Control Relay SD219

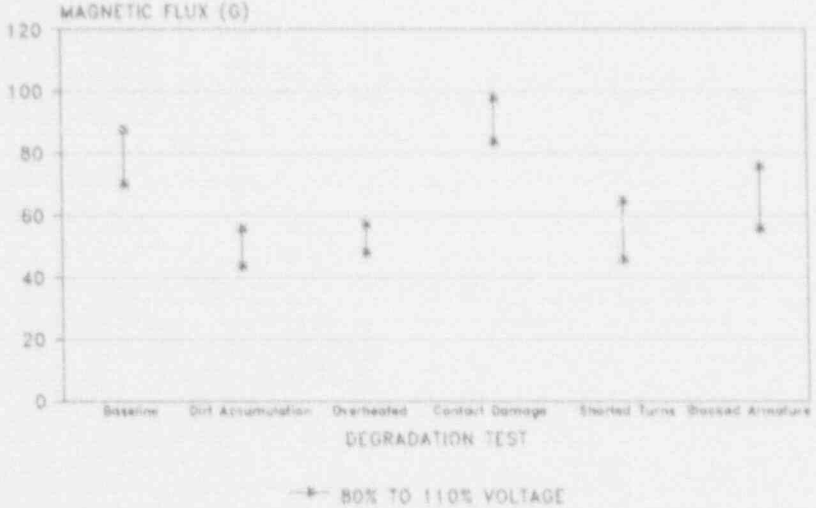


Figure 4-20. Magnetic Field
Comparison Control Relay SD219

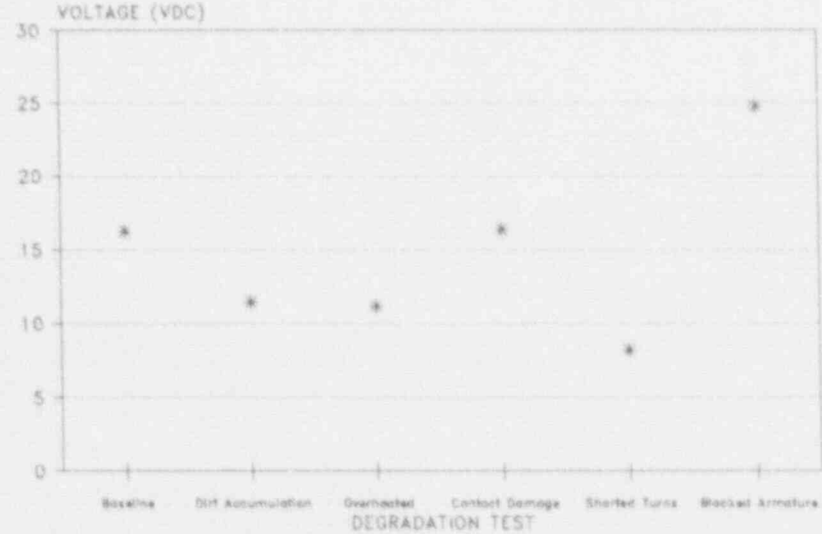


Figure 4-21. Pickup Voltage
Comparison Control Relay SD219

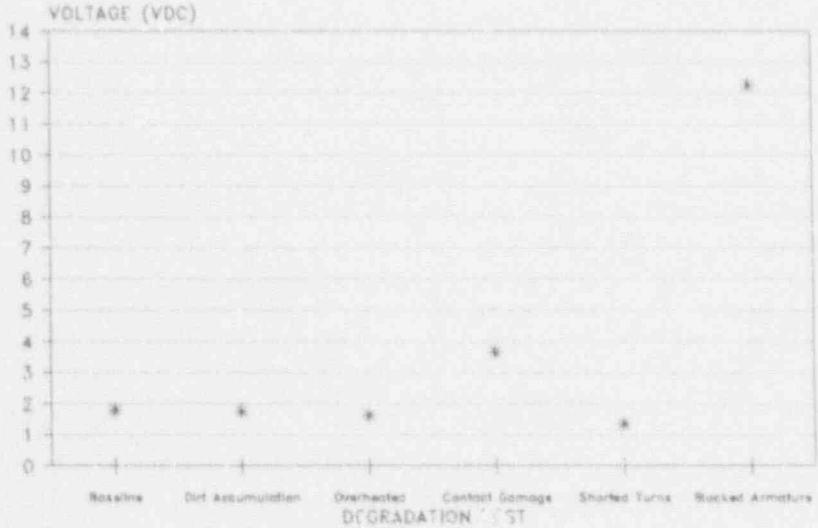


Figure 4-22. Drop-Out Voltage
Comparison Control Relay SD219

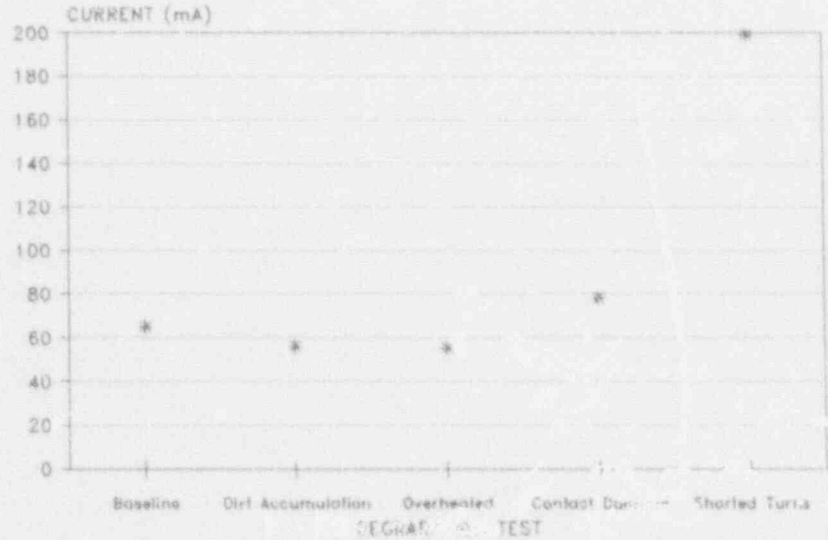


Figure 4-23. Inrush Current Comparison
Control Relay SD219

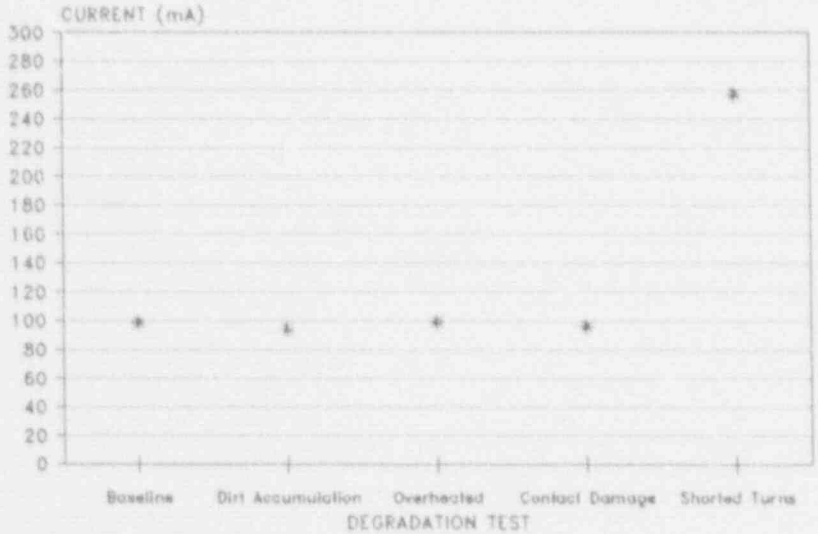


Figure 4-24. Holding Current Comparison
Control Relay SD219

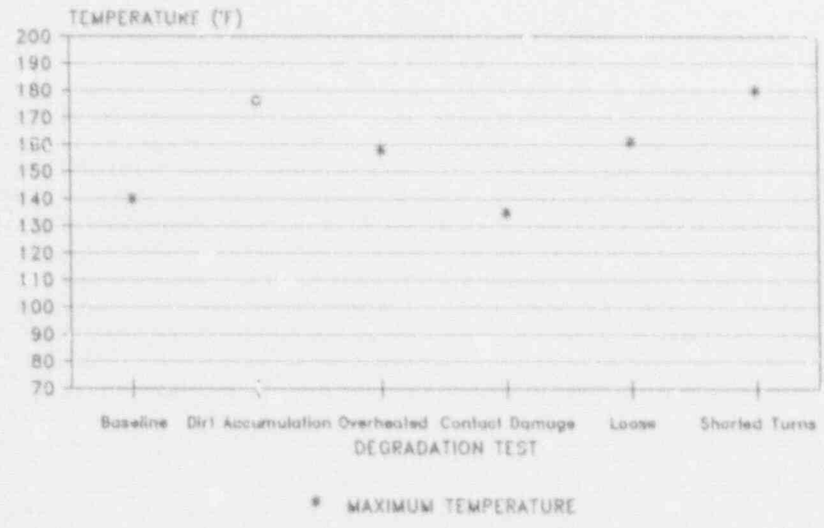


Figure 4-25. Infrared Pyrometry
Comparison Control Relay SD219

temperature of approximately 20^{o}F. Dirt accumulation and shorted coil turns caused an increase in maximum temperature of 35^{o}F and 40^{o}F, respectively. These temperature increases would be expected to reduce the expected life of the relays. A 40^{o}F temperature rise would be expected to reduce the life to approximately 25% of the original expected life.

Figure 4-26 shows the SD219 relay after overheat. This figure attests to the fact that the degraded condition after overheat was sufficiently severe as to constitute a worst case.

Vibration signature differences were caused by seven of the ten degraded conditions. Figure 4-27 shows that low contact current, and loose connections caused a peak at 1000 Hz. Contact damage resulted in a narrowing of the peak form 300 to 700 Hz. Blocked armature resulted in significant signal reduction. Overheat caused re-characterization of the vibration signature even though the relay continued to pick-up and drop out. Additionally, differences in the vibration signatures caused by the degradations of dirt accumulation and shorted coil turns were confounded and difficult to see since the changes from the overheated degradation were significant. The overheated degradation was performed prior to the degraded conditions of dirt accumulation and shorted coil turns.

Acoustic signatures were low and differences were caused by six of the ten degraded conditions. Loose connections caused a difference in the 160 to 320 Hz range, contact damage caused changes in the 20 to 140 Hz range, blocked armature caused a reduction in signal, overheated caused a re-characterization. Additionally, differences in the acoustic signatures caused by the degradations of dirt accumulation and shorted coil turns were difficult to detect since the changes from the overheated degradation caused the significant change from baseline.

Figure 4-26. Overheated Degraded Condition of Struthers-Dunn 219 Control Relay

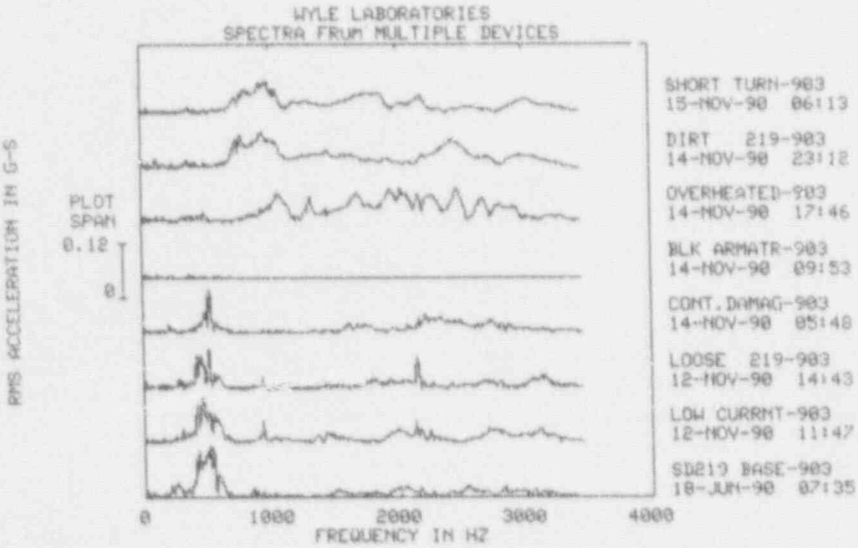


Figure 4-27. Vibration Signatures of Degraded Conditions of Struthers-Dunn 219 Control Relay

4.3 Results of Degraded Conditions on Electronic Relay

The Basler electronic relay was subjected to five degraded conditions and the ISM methods performed after each degraded condition.

The most significant findings on the protective relays were:

- Instantaneous overcurrent was 100% effective at detecting the degraded conditions,
- Vibration signatures differences were caused by all degraded conditions, but were too low to be practical.

The degraded conditions were contact damage, loose connections, overheated, dirt accumulation and high potential. The ISM methods of infrared scanning and on-contact temperature were not performed during these degradation tests on the electronic relay because the equipment was unavailable at the time the tests were performed.

The ISM methods of contact resistance, coil resistance, time/ current characteristic, infrared pyrometry, acoustic testing and ion detection did not show any significant change from the original baseline parameters during any of the degradation tests. Figures 4-28 through 4-31 show the results of contact resistance, coil resistance, overcurrent timing(time/ current characteristic), and infrared pyrometry.

The ISM methods which did show significant changes from the original baseline parameters during at least one of the degradation tests were visual inspection, overcurrent sensing pickup, instantaneous overcurrent and vibration.

Visual inspection was effective in four of the five degraded conditions. They were contact damage, dirt accumulation, overheated and loose connections.

Figure 4-32 shows the electronic relay after dirt accumulation. This figure attests to the fact that the degraded condition after dirt accumulation was sufficiently severe as to constitute a worst case.

Overcurrent sensing changed in two of the five degradation conditions. Loose connections and overheated caused at least one element to exceed the ± 2% acceptance criteria, Figure 4-33.

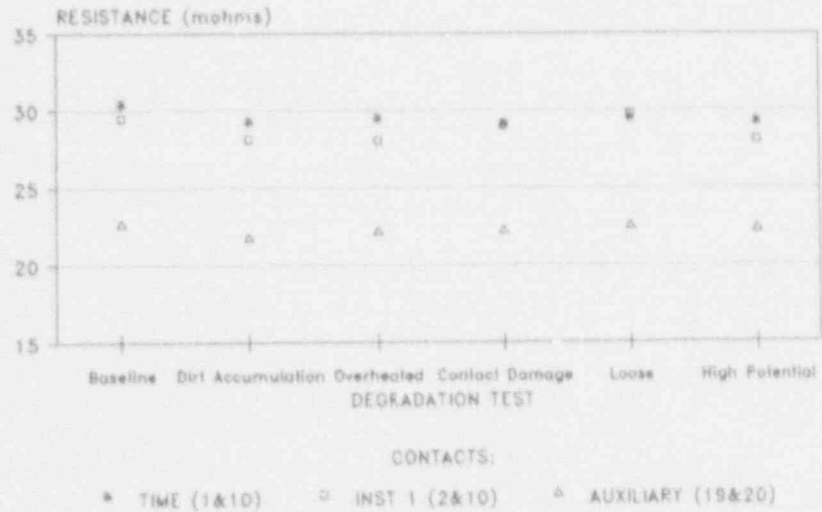


Figure 4-28. Contact Resistance Comparison Electronic Relay BE1-51

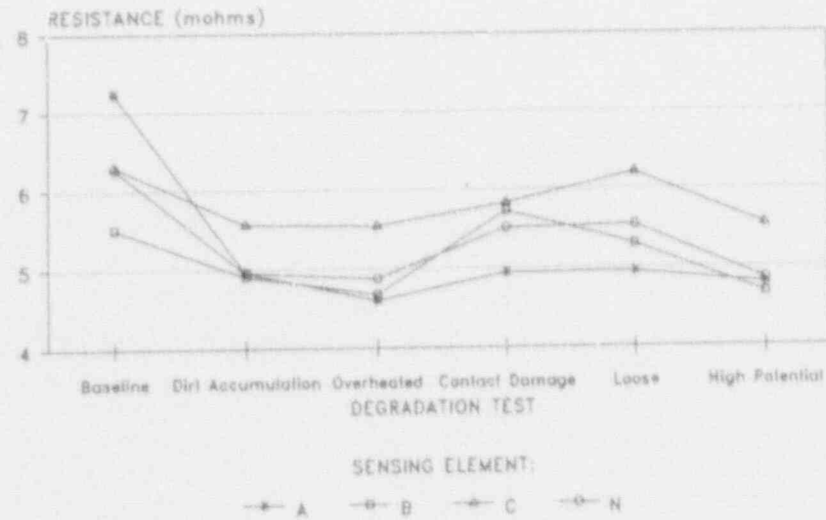


Figure 4-29. Coil Resistance Compariso Electronic Relay BE1-51

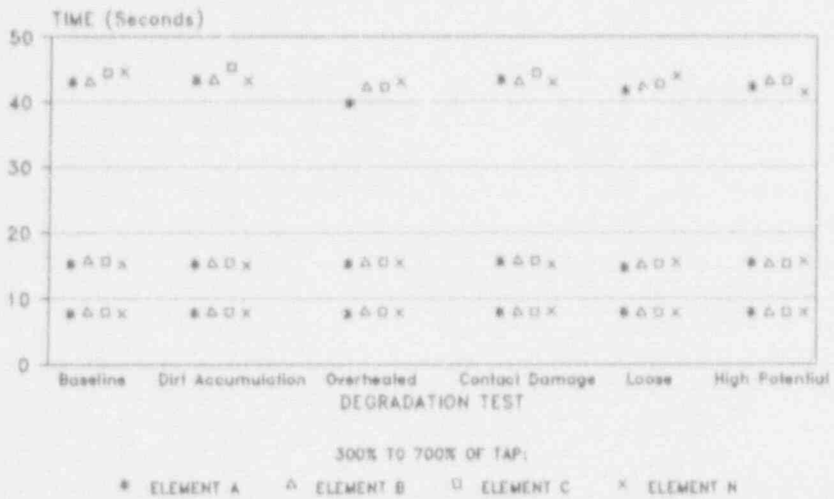


Figure 4-30. Overcurrent Timing
Comparison Electronic Relay BE1-51

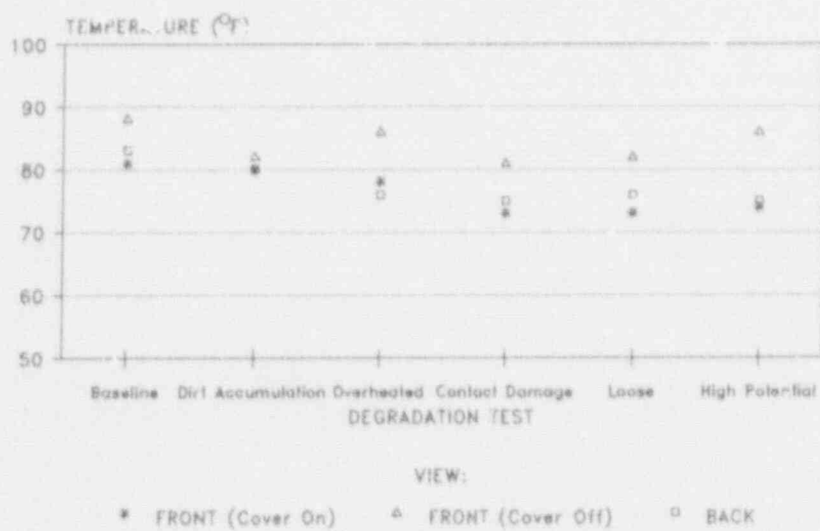


Figure 4-31. Infrared Pyrometry
Comparison Electronic Relay BE1-51

Figure 4-32. Basler Electronic Relay after Degraded Condition of Dirt Accumulation

Instantaneous overcurrent was changed in all five degraded conditions. The instantaneous overcurrent pick-up varied more than the typical acceptance criteria of ± 2% of the pick-up values obtained during baseline testing for each degraded condition for three out of four sensing elements. Only element B changed less than ± 2%, Figure 4-34. It should be noted that the levels of change may not be totally attributed to the degraded conditions since specific manufacturer's test equipment, designed in conjunction with the electronic relay, was unavailable for this research. This special test equipment may have shown less change and shown better precision for this method. The use of manufacturer's test equipment for electronic relays is recommended.

Vibration signature differences were noted among all five degraded conditions. In Figure 4-35 the vibration signatures for the five degradation conditions were compared. Differences were most noticeable with the degraded conditions of contact damage and dirt accumulation. The vibration signatures on the electronic relay were different but the levels were too low to attribute all of the changes to the degraded conditions.

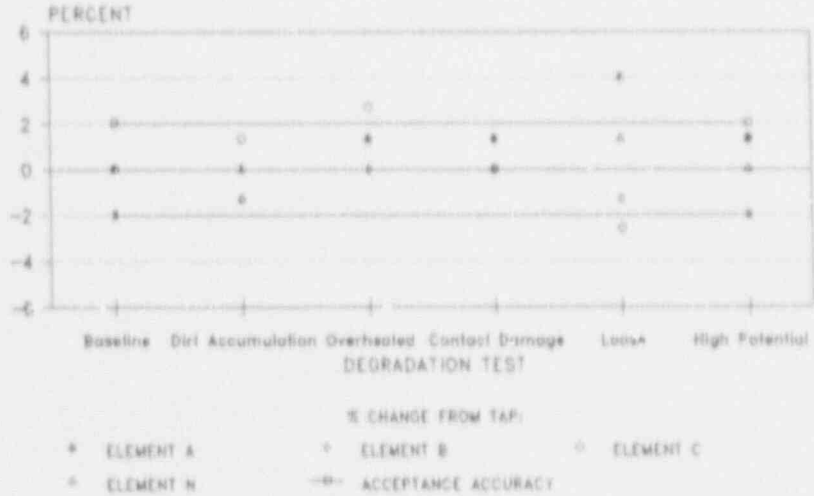


Figure 4-33. Overcurrent Sensing Pickup Comparison Electronic Relay BE1-51

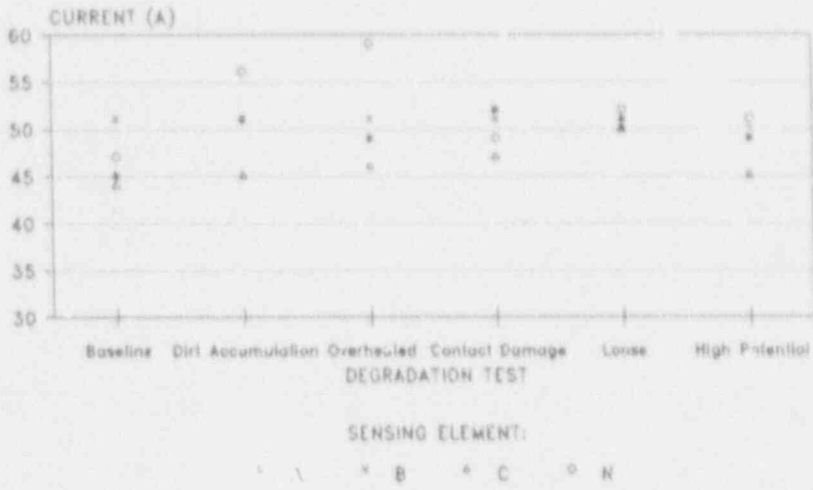


Figure 4-34. Instantaneous Current Pickup Comparison Electronic Relay BE1-51

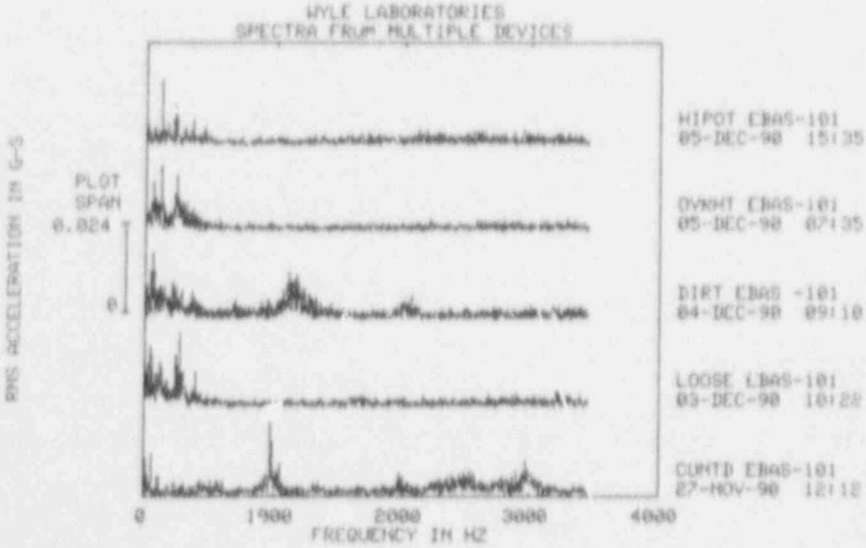


Figure 4-35. Vibration Signatures of Degraded Conditions of Basler Electronic Relay

4.4 Results of Degraded Conditions on Auxiliary Relays

Two General Electric HFA and one Westinghouse MG-6 relays were subjected to ten degraded conditions and the ISM methods were performed after each degraded condition.

The most significant findings on the auxiliary relays were:

- Pick-up voltage was insensitive to 90% of the degraded conditions,
- Insulation resistance did not show any significant change due to any of the degraded conditions,
- Infrared thermography was effective at detecting 40% of the degraded conditions,
- Almost all of the degraded conditions detected by infrared thermography were undetected by the current industry practice of pick-up voltage,
- Each of the degraded conditions detected by infrared thermography result in shortened relay life due to increased temperatures. Some of the increased temperatures would result in extremely short life expectancy and a few would be fire hazards,
- The significant temperature increases were best observed with the front cover off and by viewing at 45° from normal,
- The HFA relay was particularly sensitive to loose connections, which resulted in internal temperatures in excess of 600°F,
- The MG-6 relay was particularly sensitive to dirt accumulation, loose connections, and shorted coil turns, which resulted in internal temperatures between 390°F and 430°F,

- Vibration signatures were sensitive to 60% of the degraded conditions on the MG-6 and 40% on the HFA.

Two GE HFA relays were utilized, the 18 year relay and the 4 year relay. Since the 18 year relay was out of specification during the tests on aged devices, it was utilized on only two of the degraded conditions, low contact current and contact damage. The 4 year HFA was utilized on the other degraded conditions.

The degraded conditions were low contact current, contact damage, contact to contact short, blocked armature, shorted coil turns, dirt accumulation, overheated, increased coil resistance, loose connections and high potential tests. The ISM methods of current surge comparison, infrared scanning and on-contact temperature were not performed during these degradation tests on auxiliary relays because the equipment was unavailable at the time the tests were performed.

The ISM method of insulation resistance did not show any significant change from original baseline parameters during any of the degradation tests. The ISM methods which did show significant change from the original baseline parameters during at least one of the degradation tests were visual inspection, contact and coil resistance, magnetic flux, pick-up voltage, drop-out voltage, inrush current, holding current, infrared pyrometry, vibration testing, acoustic testing and ion detection. The contact to contact short did not significantly effect any of the ISM methods.

The visual inspection was effective in five of ten degraded conditions. They were contact damage, blocked armature, dirt accumulation, overheated, and loose connections.

Figure 4-36 shows the blistered surface on the GE HFA caused by the overheated degradation and Figure 4-37 shows the dirt accumulation degradation on the Westinghouse MG-6. It is noted that these degradations have been purposely significant in order to constitute a worst case.

Contact resistance changed significantly in two out of the ten degraded conditions on the HFA and six out of ten on the MG-6 relay. For the 4 year HFA relay, loose connections and blocked armature caused significant increases in contact resistance, Figure 4-38. This figure shows the range of contact resistances for each contact set after each of the degraded conditions. Additionally, the contact resistance of the 18 year HFA relay varied considerably in the as received condition. The contact resistance improved after operation in the low contact current test and then increased because of the contact damage degradation for the 18 year relay.

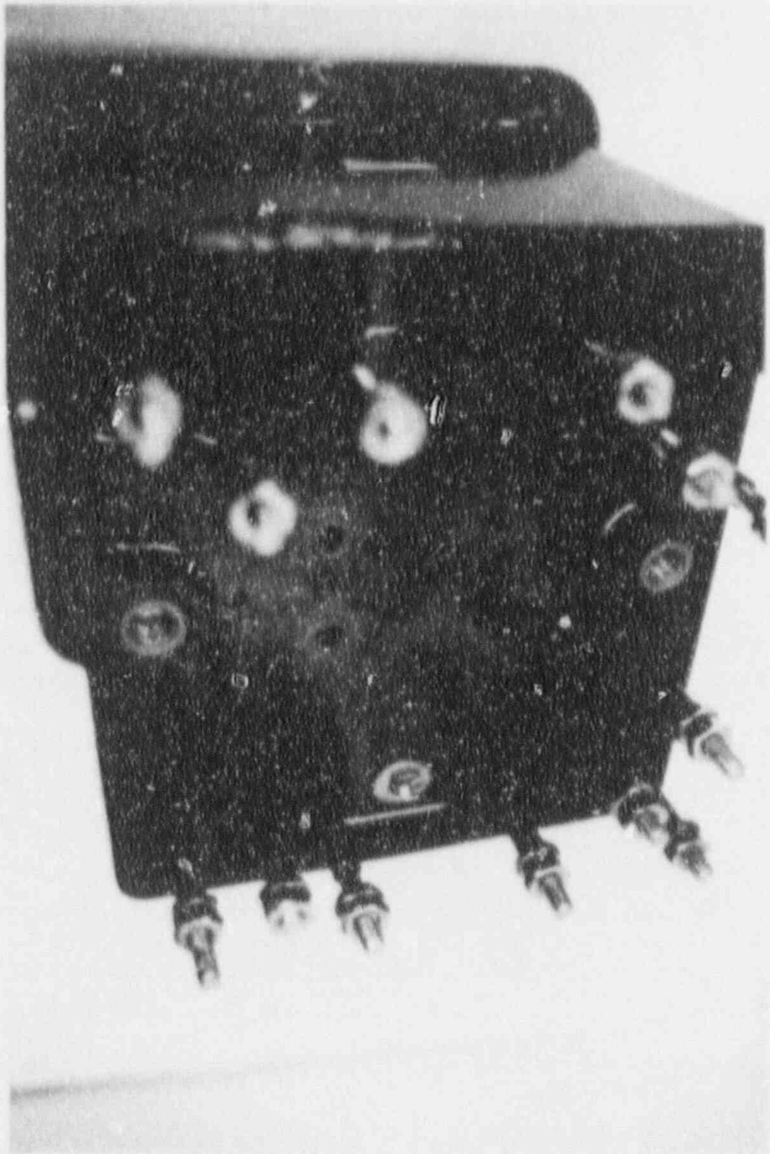


Figure 4-36. Blistered Surface on GE HFA Auxiliary Relay in Overheated Degraded Condition

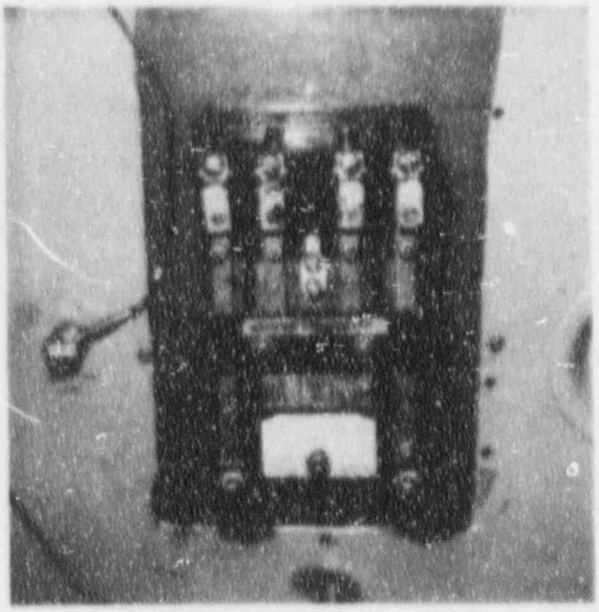


Figure 4-37. Westinghouse MG-6 Auxiliary Relay in Dirt Accumulation Degraded Condition

For the MG-6 relay, dirt accumulation, overheated, contact damage, loose connections, shorted coil turns and blocked armature caused significant increases in contact resistance, Figure 4-39. The contact resistance increased the most during the blocked armature degradation since the contacts did not fully close.

Coil resistance changed significantly in one out of the ten degraded conditions for each of the auxiliary relays. Loose connections caused an increase of 12% for the HFA relay, Figure 4-40. Shorted coil turns caused over a 25 % drop in coil resistance for the MG-6 relay, Figure 4-41.

Magnetic flux changed significantly in two of the seven degraded conditions in which it was measured on the MG-6. It was not measured on the HFA due to equipment unavailability. Shorted coil turns and blocked armature caused the magnetic flux to increase, Figure 4-42.

The significance of the pick-up voltage results was that for 90% of the degraded conditions, either there was no change in pick-up voltage or it decreased, which would normally be interpreted as improving. Thus it was only effective at detecting 10% of the degraded conditions. For the HFA relays, since the 18 year relay was out of specification for pick-up voltage in the as received condition, it decreased to within specification after the contact damage degradation. Additional comparisons were made on the 4 year HFA relay, which increased pick-up voltage in one out of eight degraded conditions. Loose connections caused an increase in pick-up voltage of 13%, Figure 4-43. Pick-up voltage changed in two of the ten degraded conditions for the MG-6 relay. Contact damage caused pick-up voltage to increase and shorted coil turns caused pick-up voltage to decrease, Figure 4-44.

Drop out voltage changed significantly in one out of the ten degraded conditions on the HFA and five out of ten on the MG-6 relay. For the HFA relay, Figure 4-45, the blocked armature degradation caused an increase in drop out voltage of over 400%. For the MG-6 relay, the degraded conditions of dirt accumulation, loose connections and shorted coil turns caused a decrease in drop out voltage and contact damage and blocked armature caused increases in drop out voltage, Figure 4-46.

Inrush current changed significantly in three out of the ten degraded conditions for the MG-6. The degraded conditions of dirt accumulation and shorted coil turns caused increases of 40% and 68% respectively, Figure 4-47. The contact damage degradation caused a decrease of 34% in the inrush current.

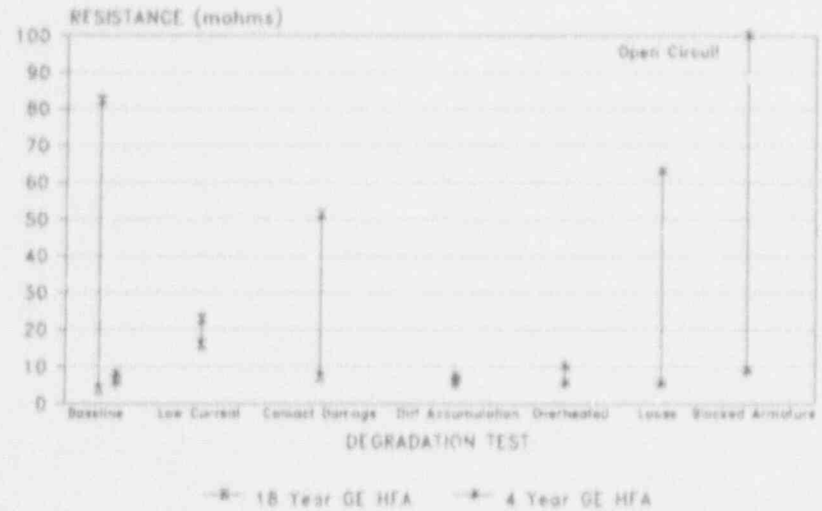


Figure 4-38. Contact Resistance
Comparison Auxiliary Relay GE HFA

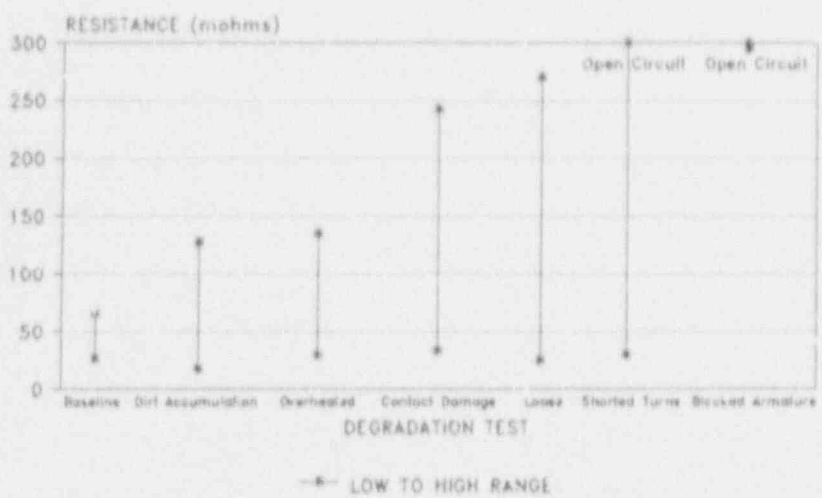


Figure 4-39. Contact Resistance
Comparison Auxiliary Relay
Westinghouse MG-6

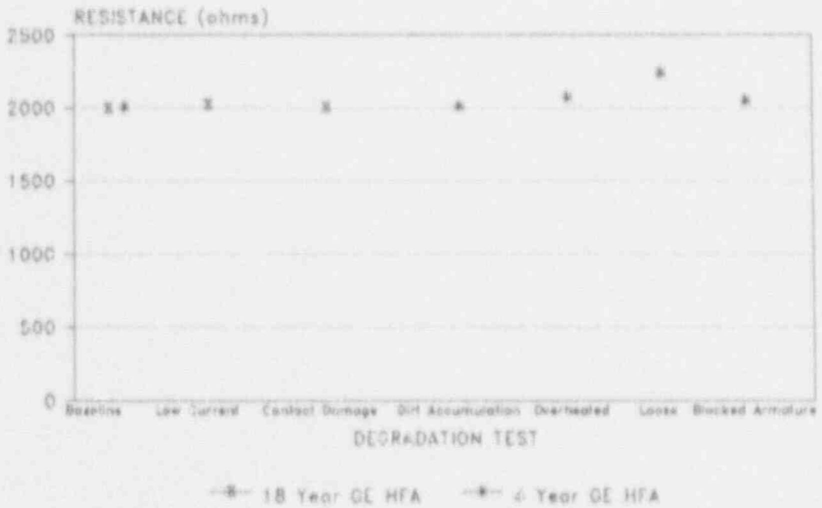


Figure 4-40. Coil Resistance
Comparison Auxiliary Relay GE HFA

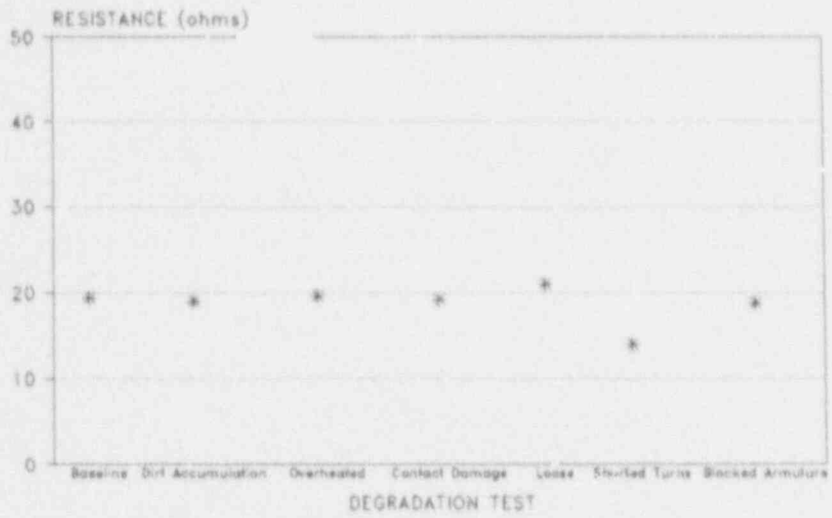


Figure 4-41. Coil Resistance
Comparison Auxiliary Relay
Westinghouse MG-6

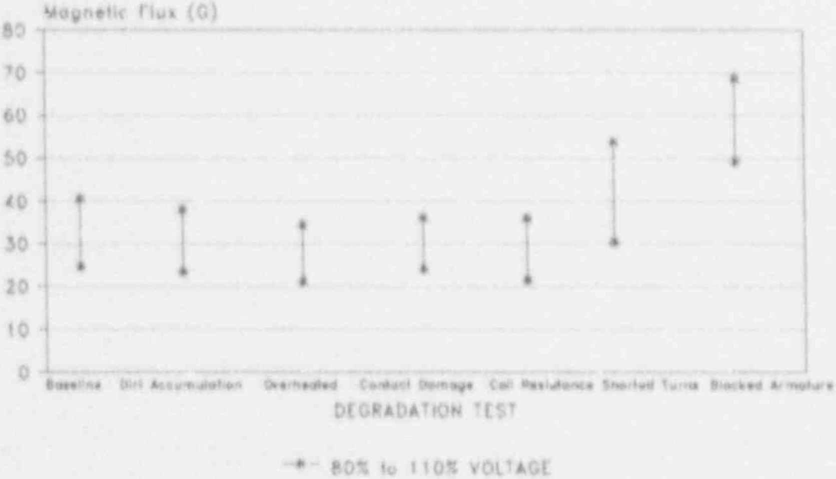


Figure 4-42. Magr.etic Field
Comparison Auxiliary Relay
Westinghouse MG-6

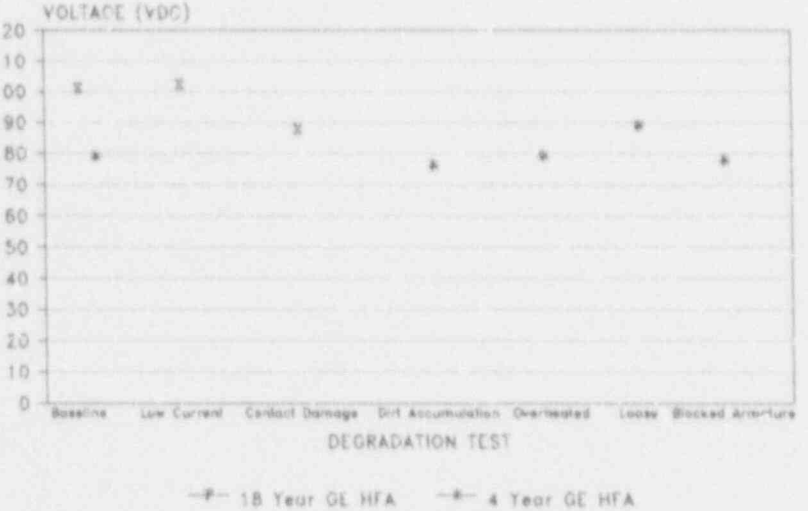


Figure 4-43. Pick-up Voltage
Comparison Auxiliary Relay GE HFA

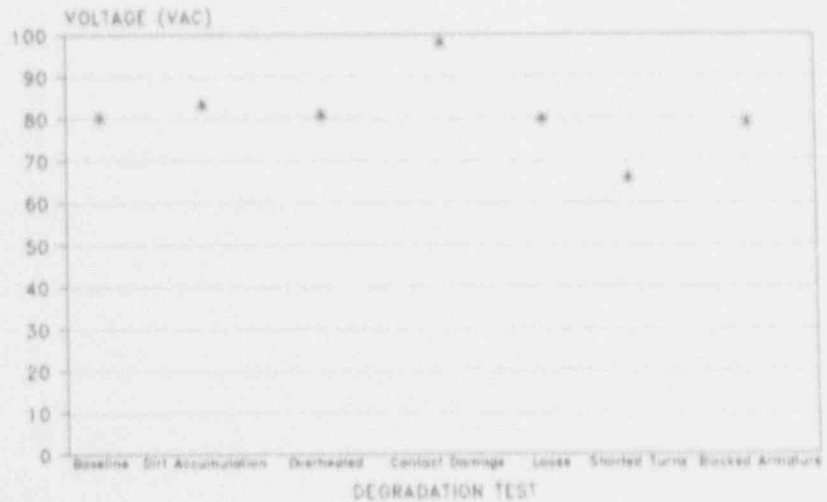


Figure 4-44. Pick-up Voltage
Comparison Auxiliary Relay
Westinghouse MG-6

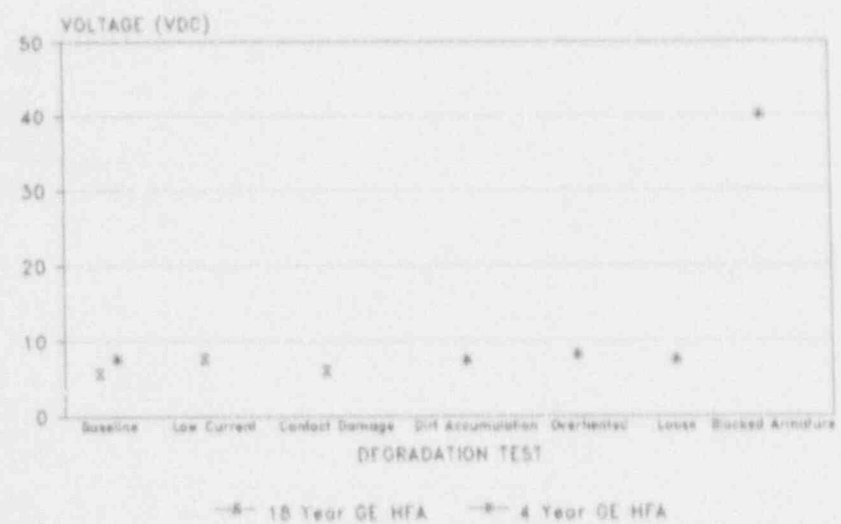


Figure 4-45. Drop Out Voltage
Comparison Auxiliary Relay GE HFA

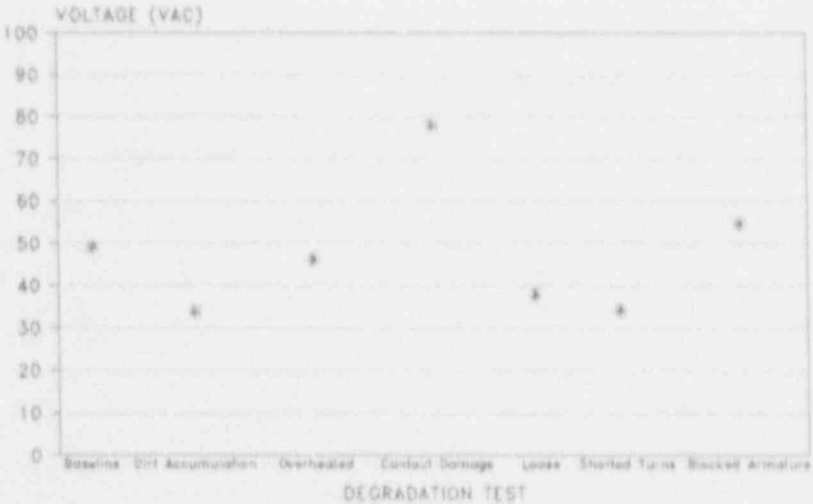


Figure 4-46. Drop Out Voltage
Comparison Auxiliary Relay
Westinghouse MG-6

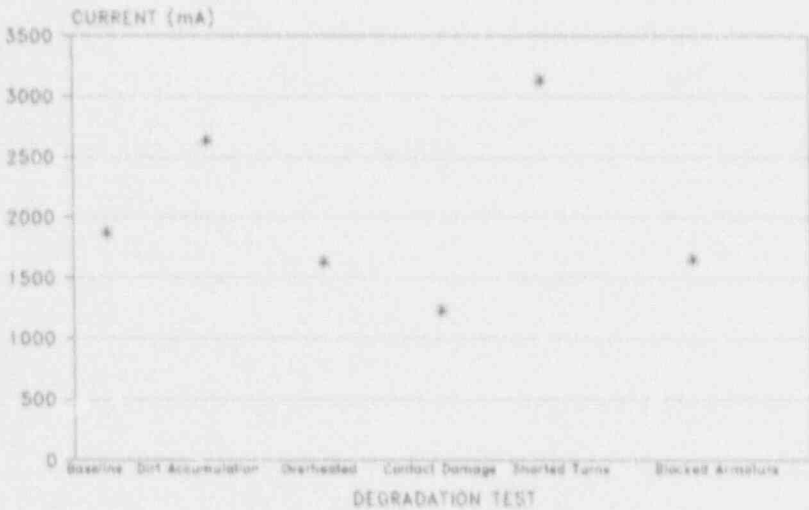


Figure 4-47. Inrush Current
Comparison Auxiliary Relay
Westinghouse MG-6

Holding current did not significantly change in the HFA relay, Figure 4-48, but did change significantly in two out of the ten degraded conditions on the MG-6 relay. Shorted coils turns caused an increase of over 100% and blocked armature caused an increase of 50% in the holding current, Figure 4-49. The excessive current drawn during the shorted coil turns test also caused significant temperature increases(over 300°F on the case) and produced smoke, visible through the glass on the case.

Infrared pyrometry showed temperature changes in four out of ten degraded conditions for the HFA and MG-6 relays. For the HFA relay, the degraded conditions of dirt accumulation, overheated, loose connections and blocked armature caused significant temperature increases. The HFA relay had a glass cover which masked some significant temperature changes, when it was in place. Figure 4-50 shows the maximum temperatures for the HFA with the cover on. Degraded conditions of dirt accumulation, overheated and blocked armature caused an increase of approximately 10°F. The loose connections degradation caused an increase of 100°F to be visible with the cover on. With the cover removed, the degraded conditions of dirt accumulation, overheated and blocked armature were noted to have caused an actual increase of approximately 30°F and the degraded condition of loose connections to have caused a temperature in excess of 600°F, Figure 4-51.

Of interest on the HFA was the difference in temperature observed when different viewing angles were used. Figure 4-52 shows the three viewing angles of left 45°, normal to the relay (90°) and right 45°, with the cover on when the baseline temperatures were compared with the loose connection degradation. With the cover on, viewing angle had little effect. With the cover removed, Figure 4-53, viewing angle resulted in an almost 200°F difference in hot spot.

For the MG-6 relay, the degraded conditions of dirt accumulation, overheated, loose connections and shorted coil turns caused significant temperature increases. This relay also had a glass cover which masked some significant temperature changes, when it was in place. Figure 4-54 shows the maximum temperatures for the MG-6 relay with the cover on. Degraded conditions of dirt accumulation and overheated caused an increase of approximately 30°F. The loose connections degradation caused an increase of 120°F and the shorted coil turns degradation caused an increase of 170°F to be visible with the cover on.

With the cover off, the degraded conditions of dirt accumulation, loose connections and shorted coil turns had caused temperature increases of approximately 200°F, Figure 4-55.

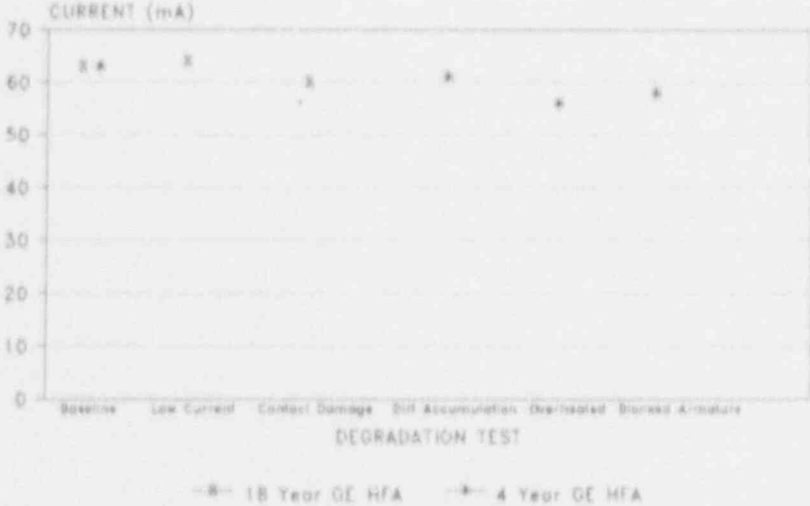


Figure 4-48. Holding Current
Comparison Auxiliary Relay GE HFA

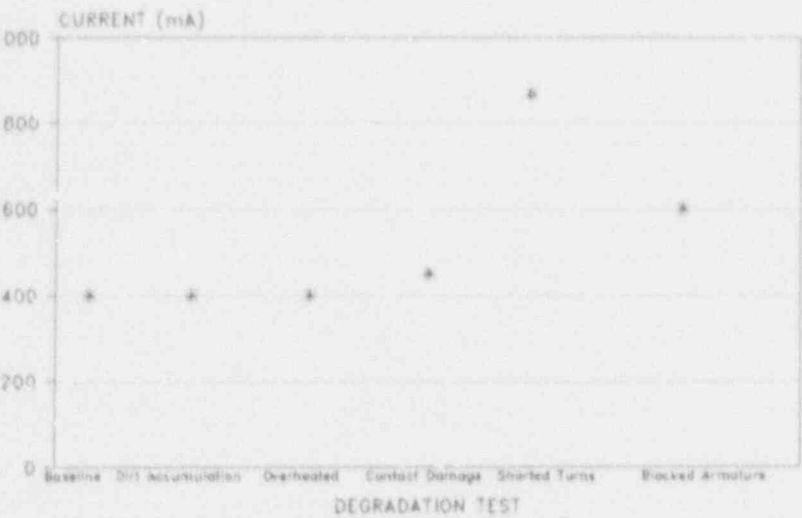


Figure 4-49. Holding Current
Comparison Auxiliary Relay
Westinghouse MG-6

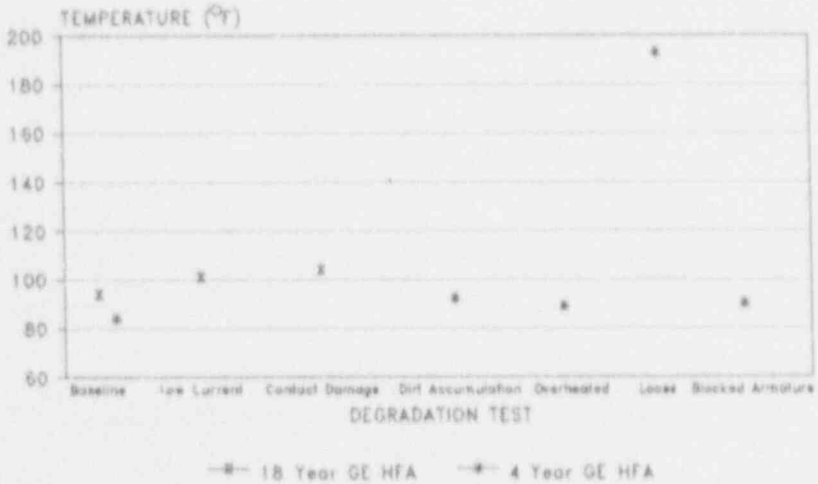


Figure 4-50. Infrared Pyrometry
Comparison Auxiliary Relay GE HFA
(Cover on)

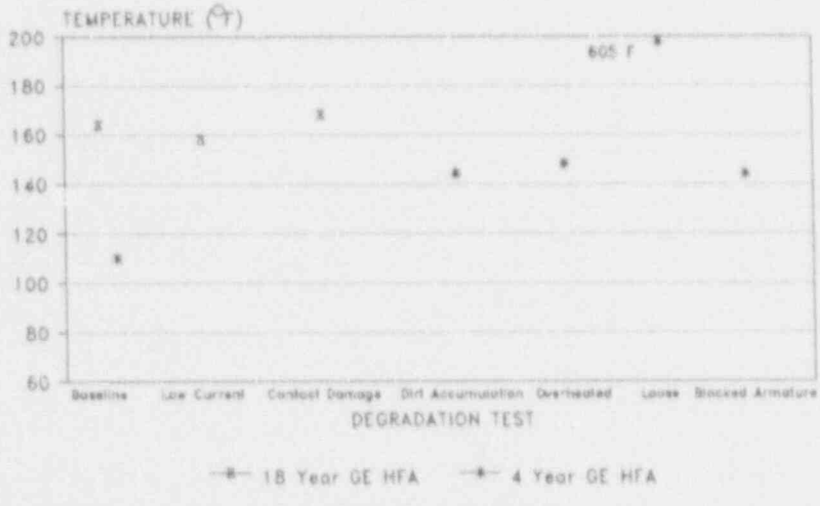


Figure 4-51. Infrared Pyrometry
Comparison Auxiliary Relay GE HFA
(Cover off)

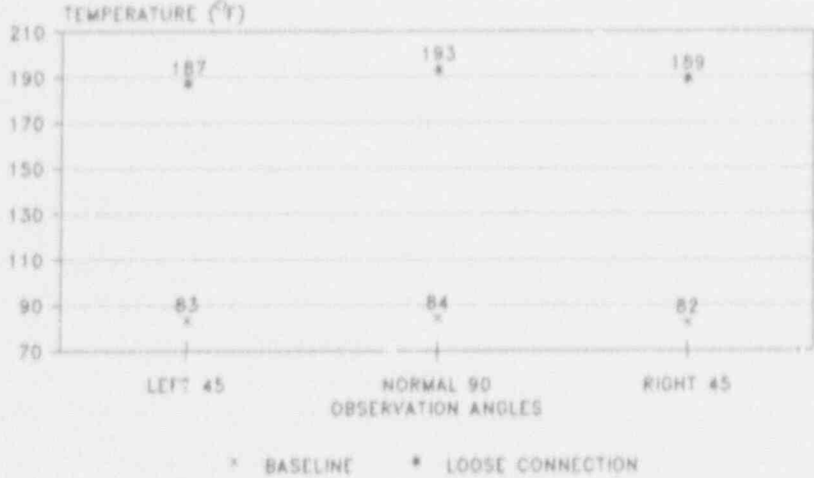


Figure 4-52. Infrared Pyrometry Comparison of Viewing Angles for HFA Baseline and Loose Connection:Cover on

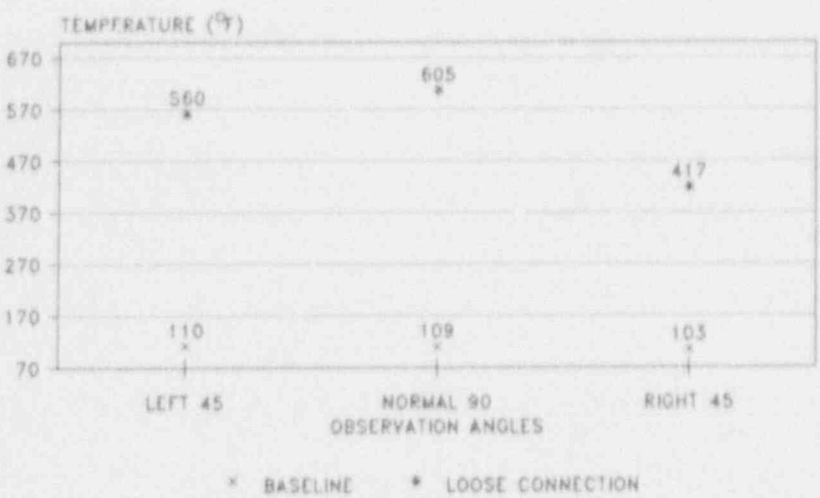


Figure 4-53. Infrared Pyrometry Comparison of Viewing Angles for HFA, Baseline and Loose Connection:Cover off

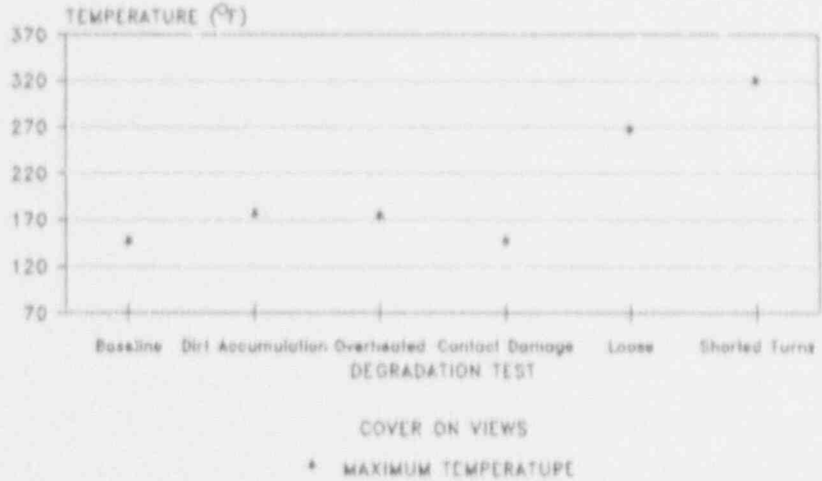


Figure 4-54. Infrared Pyrometry
Comparison Auxiliary Relay MG-6
(Cover on)

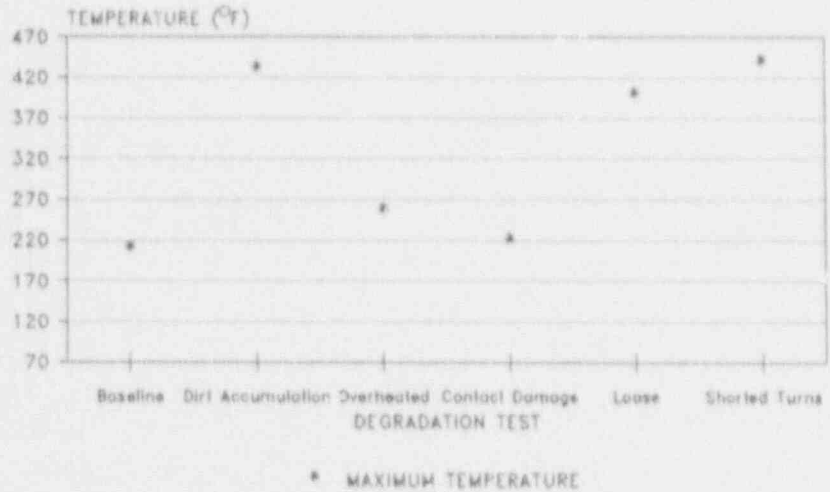


Figure 4-55. Infrared Pyrometry
Comparison Auxiliary Relay MG-6
(Cover off)

Also of interest on the MG-6 relay was the difference in temperature observed when different viewing angles were used. Figure 4-56 shows the three viewing angles of left 45^{o}, normal to the relay (90^{o}) and right 45^{o}, with the cover on when the baseline temperatures were compared with the loose connection degradation. With the cover on, viewing angle had little effect during baseline measurements, but did show a difference of 40^{o}F in the loose connection degradation. With the cover removed, Figure 4-57, viewing angle results in an almost 80^{o}F difference in hot spot during baseline measurements and a 50^{o}F difference during the loose connection degradation. Since dirt accumulation had caused a higher increase in maximum temperature, viewing angles were also compared. In Figure 4-58, viewing angle showed little difference with the cover on. With the cover off, a difference of 100^{o}F was noted due to the viewing angle, Figure 4-59. The temperature of 472^{o}F was found on a contact finger where the connection to the rear terminal post was made. This extreme temperature on the contact was due to the build up of foreign material on the contact surface, creating a poor electrical connection.

During the shorted coil turns degradation, the maximum temperature, with the cover off was 442^{o}F.

Vibration signature differences were caused by four of the ten degraded conditions for the HFA relay and six out of ten for the MG-6 relay. For the HFA relay, significant vibration signature differences were caused by loose connections, blocked armature, overheated and dirt accumulation, Figure 4-60. Loose connections caused a reduction in the peak at 731 Hz. Blocked armature resulted in significant signal reduction. Overheat caused re-characterization of the vibration signature by adding peaks at 328 and 630 Hz, even though the relay continued to pick-up and drop out. The degraded condition of dirt accumulation caused a narrowing of the peak at 630 Hz.

For the MG-6 relay, significant vibration signature changes were caused by loose connections, overheated, increased coil resistance, blocked armature, shorted coil turns and dirt accumulation. In the blocked armature degraded condition, excessive chatter and arcing of the contacts occurred as the relay attempted to close. This caused an extremely high vibration, Figure 4-6' Additionally, increased coil resistance caused a reduction in signal; loose connections caused a peak at 285 Hz; overheated resulted in narrowing the peak at 121 Hz; shorted coil turns caused a peak at 280 Hz and dirt accumulation reduced the peak at 121 Hz.

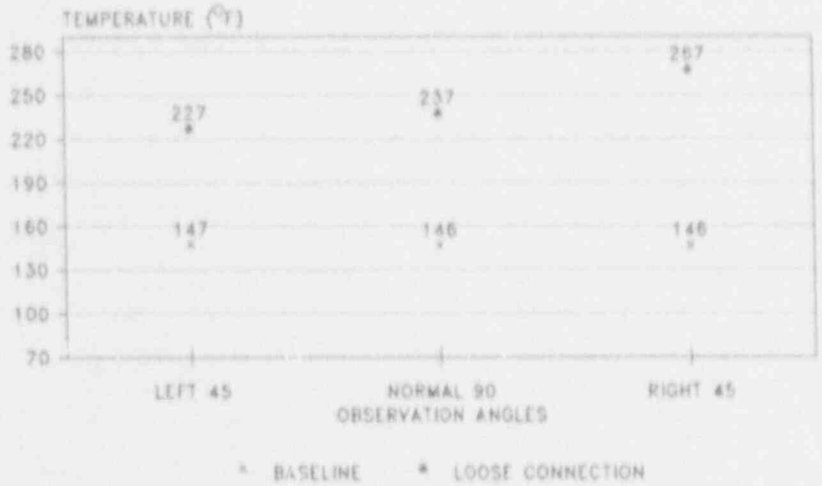


Figure 4-56. Infrared Pyrometry
Comparison of Viewing Angles for MG-6
Baseline and Loose Connection:Cover on

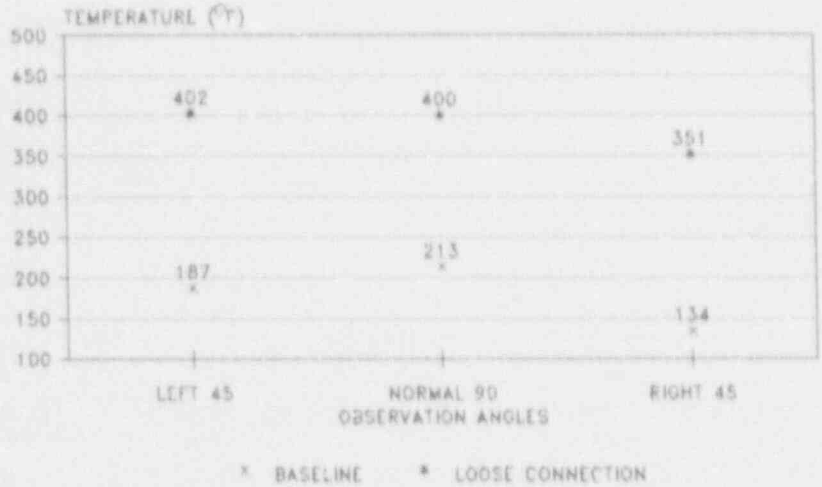


Figure 4-57. Infrared Pyrometry
Comparison of Viewing Angles for MG-6
Baseline and Loose Connection:Cover off

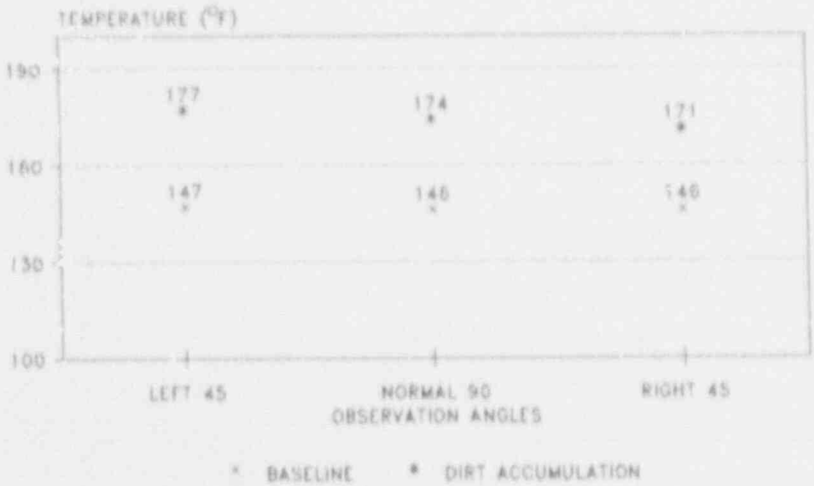


Figure 4-58. Infrared Pyrometry
Comparison of Viewing Angles for MG-6
Baseline and Dirt Accumulation:Cover on

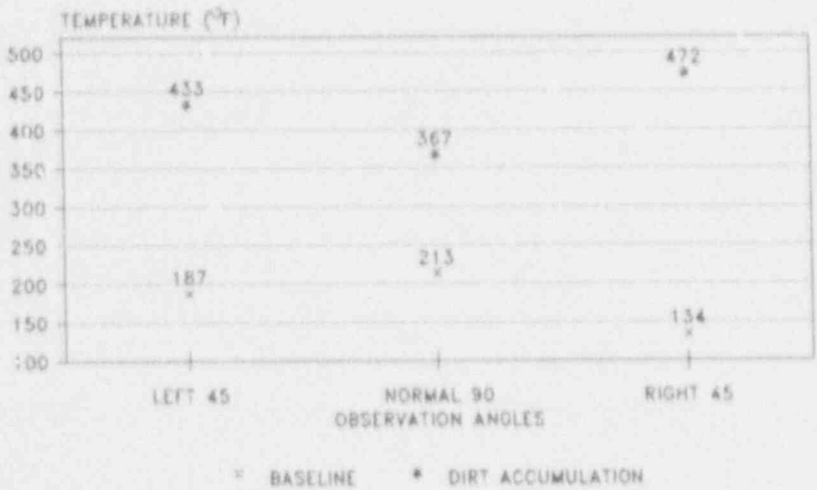


Figure 4-59. Infrared Pyrometry
Comparison of Viewing Angles for MG-6
Baseline and Dirt Accumulation:Cover off

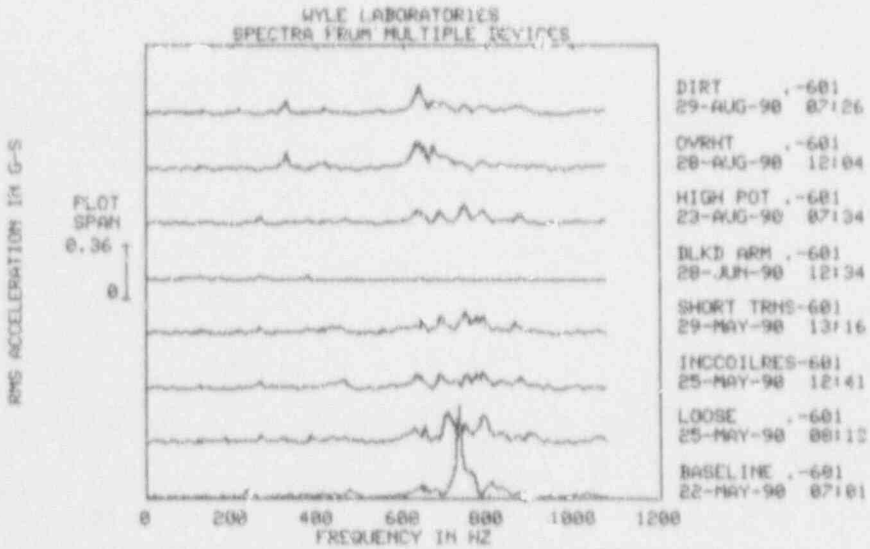


Figure 4-60. Vibration Signatures of
GE HFA Auxiliary Relays During Degraded Conditions

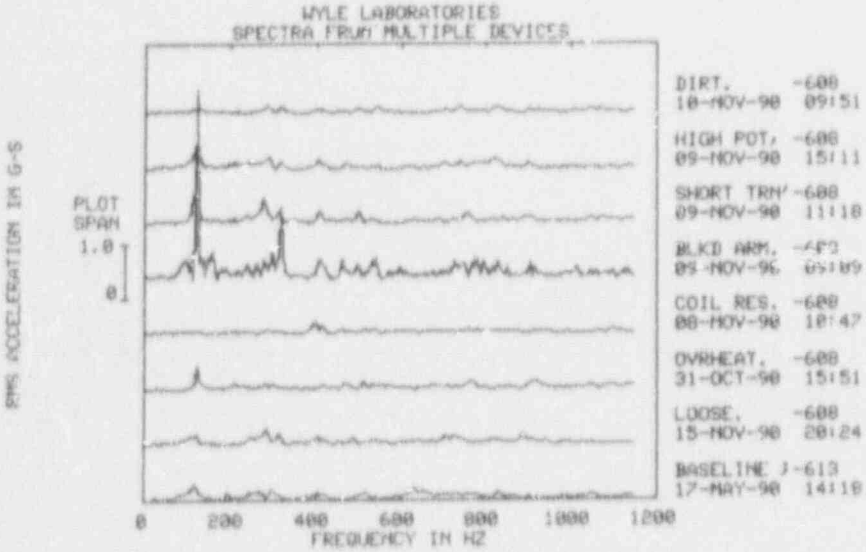


Figure 4-61. Vibration Signatures of Westinghouse MG-6 Auxiliary Relays During Degraded Conditions

Acoustic signature differences were caused by four of the ten degraded conditions for the HFA relay and six out of ten for the MG-6 relay. For the HFA relay, loose connections, overheat and dirt accumulation caused differences predominantly in the 200 HZ and 600 to 800 HZ ranges, but the most significant differences were caused by blocked armature in which the signature was reduced. For the MG-6 relay, differences in acoustic signature were caused by loose connections, overheated, increased coil resistance, shorted coil turns and dirt accumulation, but the most significant differences were caused by the blocked armature degradation in which the signature was increased.

Smoke was visible in the relay case and the ion detectors alarmed during two of the degraded conditions on the MG-6 relay. The temperatures resulting from the loose connections and shorted coil turns degradations caused smoke. However, in the case of the shorted coil turns, smoke was visible inside the case through the glass cover before it was sufficiently concentrated to be detected by the ion detector.

4.5 Results of Degraded Conditions on Timing Relays

One Agastat timing relay was subjected to nine degraded conditions and the ISM methods were performed after each degraded condition.

The most significant findings on the timing relays were:

- o Pick-up voltage was insensitive to all nine degraded conditions,
- o Inrush current was sensitive to 55% of the degraded conditions,
- o Infrared thermography was effective at detecting 55% of the degraded conditions,
- o Each of the degraded conditions detected by infrared thermography result in shortened relay life due to increased temperatures. The increased temperatures in some of the degraded conditions would result in a life expectancy of 6% to 25% of the original expected life,
- o The timing relay was sensitive to dirt accumulation, overheat, loose connections, increased coil resistance and shorted coil turns. The shorted coil turns increased the maximum temperature by over 60^{O}F,
- o Vibration signatures were sensitive to 66% of the degraded conditions.

The degraded conditions were low contact current, contact damage, blocked armature, shorted coil turns, dirt accumulation, overheated, increased coil resistance, loose connections and high potential tests. The ISM methods of on-contact temperature and current surge comparison were not performed during these degradation tests on timing relays because the equipment was unavailable at the time the tests were being performed.

The ISM methods of insulation resistance and ion detection did not show any significant change from original baseline parameters during any of the degradation tests. The ISM methods which did show significant change from the original baseline parameters during at least one of the degradation tests were visual inspection, contact resistance, coil resistance, magnetic flux, pick-up voltage, drop-out voltage, inrush current, holding current, timing, infrared pyrometry, infrared scanning, vibration testing, and acoustic testing.

Visual inspection was effective in three of nine degraded conditions. They were dirt accumulation, overheated and loose connections. Since the contacts, coil and timing head are enclosed, visual inspection is limited to a few external observations. Figure 4-62 shows the setup for the degradation testing of the timing relay.

Contact resistance changed significantly in one out of the nine degraded conditions. The contact damage of soldering two contacts together caused an open circuit. Figure 4-63 shows the range of contact resistances for each contact set after each of the degraded conditions.

Coil resistance changed significantly in one out of the nine degraded conditions. Shorted coil turns caused a 15 % drop in coil resistance, Figure 4-64.

Magnetic flux changed significantly in two of the nine degraded conditions. Shorted coil turns caused the magnetic flux to increase at 110% voltage, Figure 4-65, and the overheated degradation caused a reduction.

The significance of the pick-up voltage results was that none of the degraded conditions caused the pick-up voltage to increase. Thus, pick-up voltage did not indicate the presence of any of the degraded conditions. Pick-up voltage only changed, a reduction, in one out of the nine degraded conditions, and this would normally be misinterpreted as an improvement. Shorted coil turns caused a 10% reduction in pick-up voltage, Figure 4-66.

Drop-out voltage changed in two of the nine degraded conditions, Figure 4-67. Both the dirt accumulation and shorted coil turns degraded conditions caused drop out voltage to increase approximately 50%.

Inrush current changed significantly in five of the nine degraded conditions, Figure 4-68. The degraded conditions of dirt accumulation and loose connections caused inrush increases over 50%. The degraded conditions of overheated and contact damage caused increases over 100% and shorted coil turns caused an increase of over 400%.

Holding current changed significantly in one of the nine degraded conditions, Figure 4-69. The degraded condition of shorted coil turns caused an increase of 45% in holding current.

Timing changed significantly in three of the nine degraded conditions, Figure 4-70. The degraded conditions of contact damage, loose connections and blocked armature caused changes. The

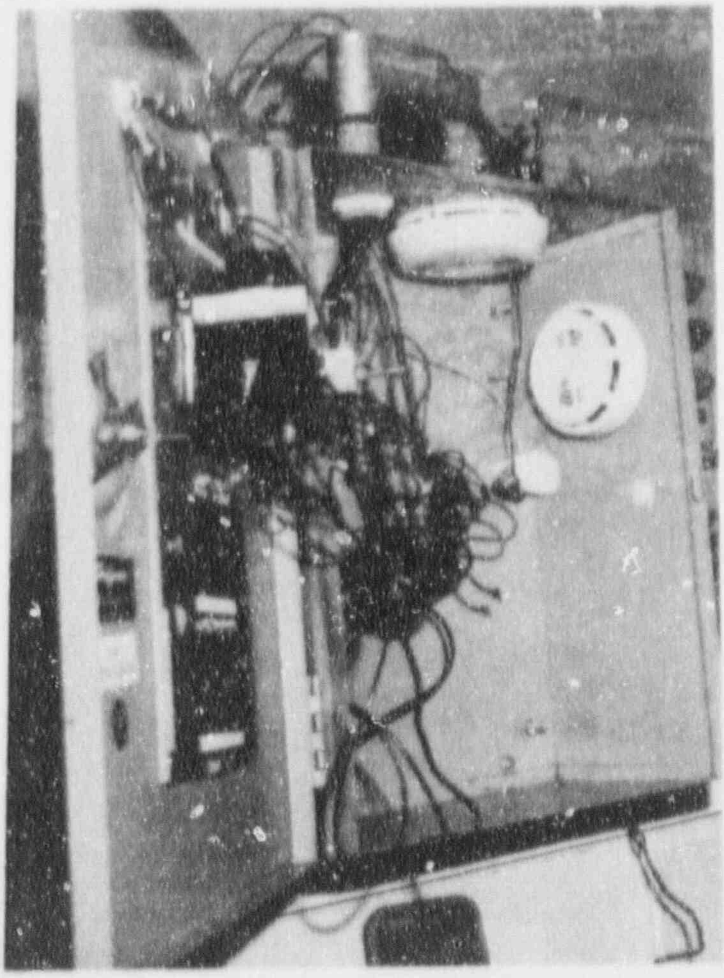


Figure 4-62. Timing Relay
Undergoing Degradation Condition Tests

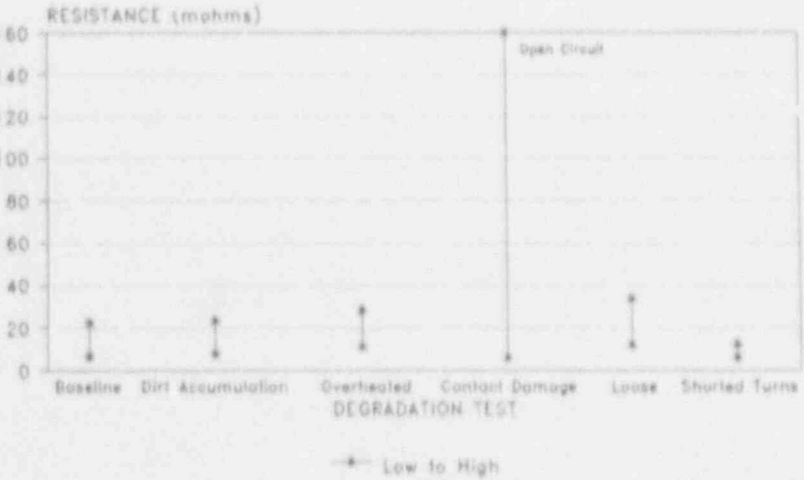


Figure 4-63. Contact Resistance
Comparison Degradation Tests
Timing Relays

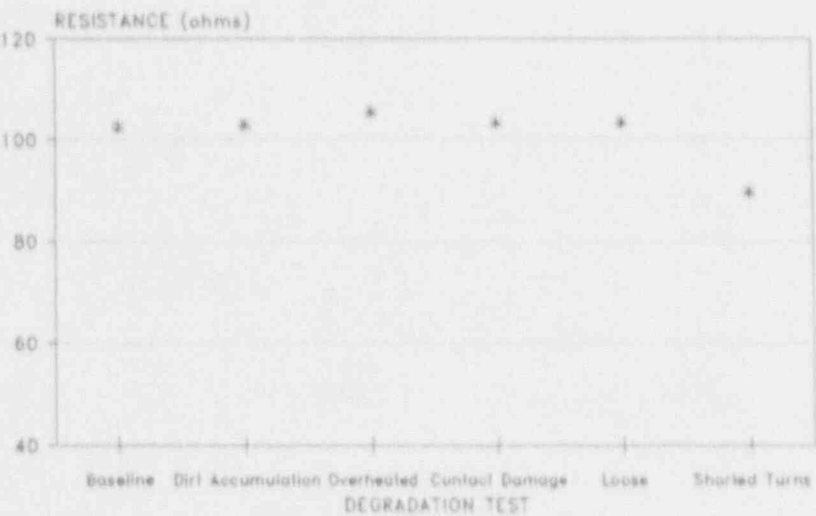


Figure 4-64. Coil Resistance
Comparison Degradation Tests
Timing Relays

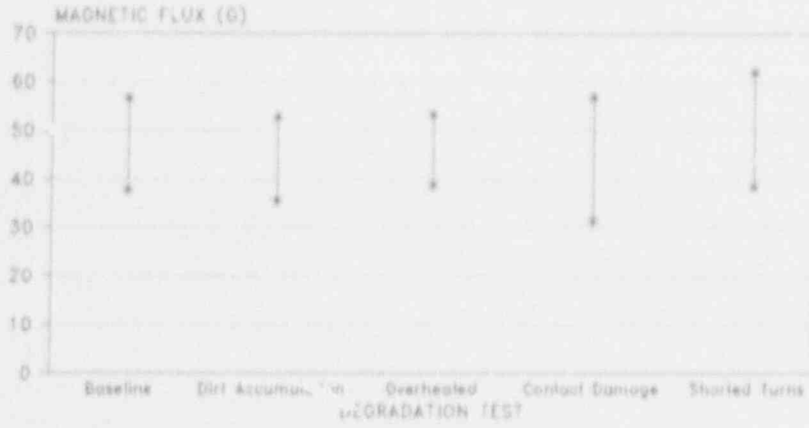


Figure 4-65. Magnetic Field
Comparison Degradation Tests
Timing Relays

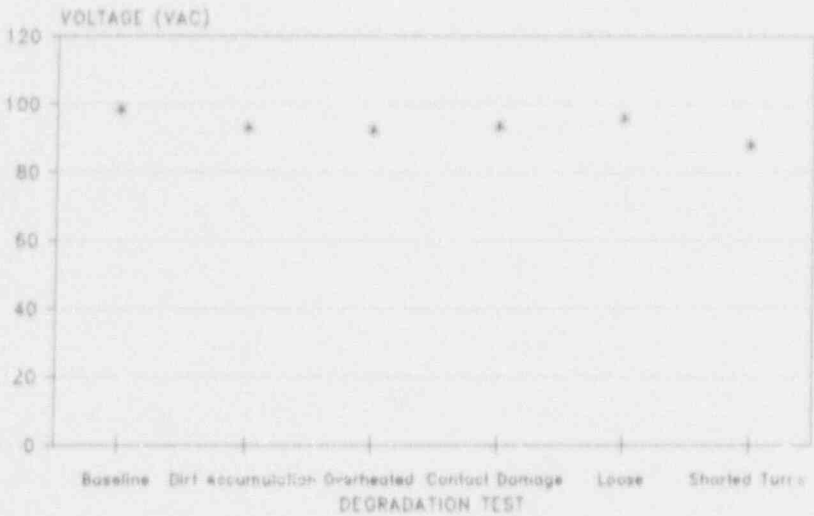


Figure 4-66. Pick-Up Voltage
Comparison Degradation Tests
Timing Relays

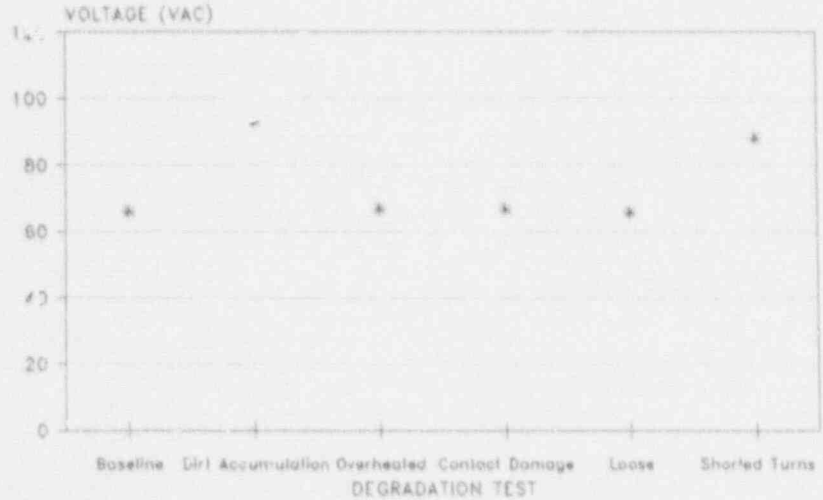


Figure 4-67. Drop Out Voltage
Comparison Degradation Tests
Timing Relays

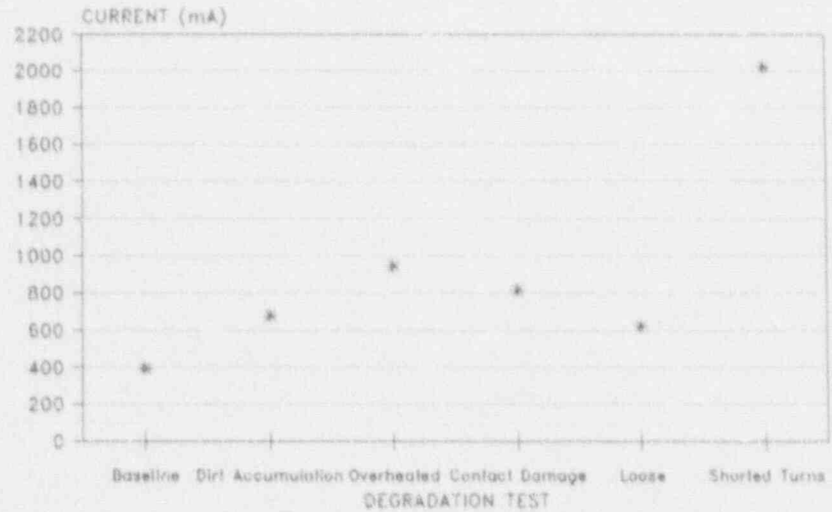


Figure 4-68. Inrush Current
Comparison Degradation Test
Timing Relays

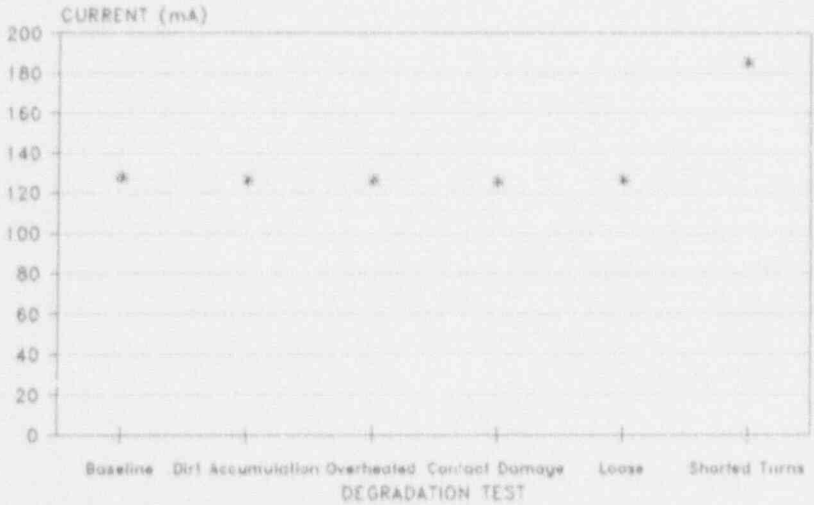


Figure 4-69. Holding Current
Comparison Degradation Tests
Timing Relays

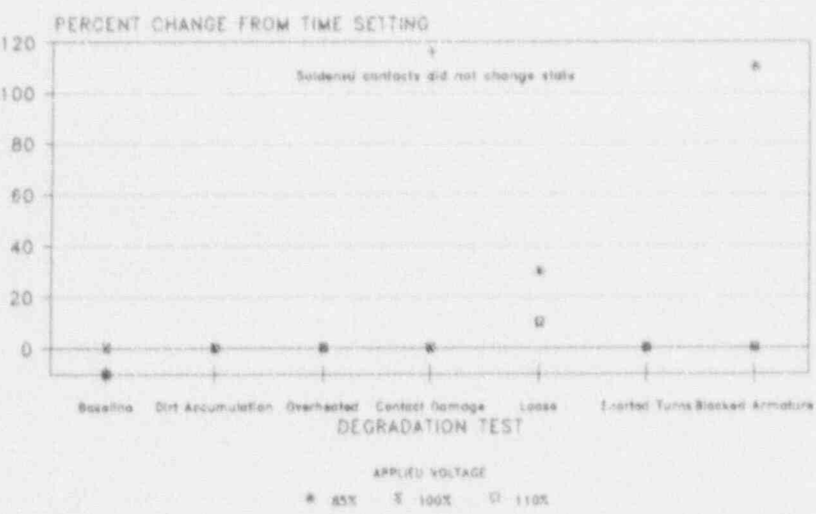


Figure 4-70. Timing
Comparison Degradation Tests
Timing Relays

contact damage of two contacts soldered together prevented the contacts from changing state. The loose connection and blocked armature degradations caused the time delay to increase out of the typical specification of ±10%, when tested at 85% of rated voltage.

Infrared pyrometry showed temperature changes in five out of nine degraded conditions, Figure 4-71. An increase in temperature of 10°F was caused by the degraded condition of dirt accumulation. The degraded conditions of overheated, loose connections and increased coil resistance caused an increase in temperature of 20 to 30°F. The degraded condition of shorted coil turns caused an increase in temperature of approximately 60°F. These increased temperatures would be expected to reduce the life of the timing relays. When an Arrhenius relationship is used to calculate expected life, a temperature increase of 30°F would be expected to result in an expected life of approximately 25% of the original expected life. A temperature increase of 60°F would result in an expected life of less than 6% of the original life.

Infrared scanning showed temperature changes in four out of the seven degraded conditions in which it was measured, Figure 4-71. The equipment was unavailable for the degradations of contact damage and loose connections. Infrared scanning showed higher temperatures than the pyrometer since it could better pinpoint the hottest spot, as shown in thermograph of Figure 4-72, which was taken with the Inframetrics Thermal Imaging System 600. It showed the same trend as the infrared pyrometer.

Vibration signature differences were caused by six of the nine degraded conditions for the timing relays. Significant vibration signature differences were caused by contact damage, loose connections, blocked armature, increased coil resistance, overheated and dirt accumulation, Figure 4-73.

Acoustic signature differences were caused by two of the nine degraded conditions for the timing relays. The degraded conditions of blocked armature and overheat caused the most significant differences predominantly in the 90 to 120 Hz range.

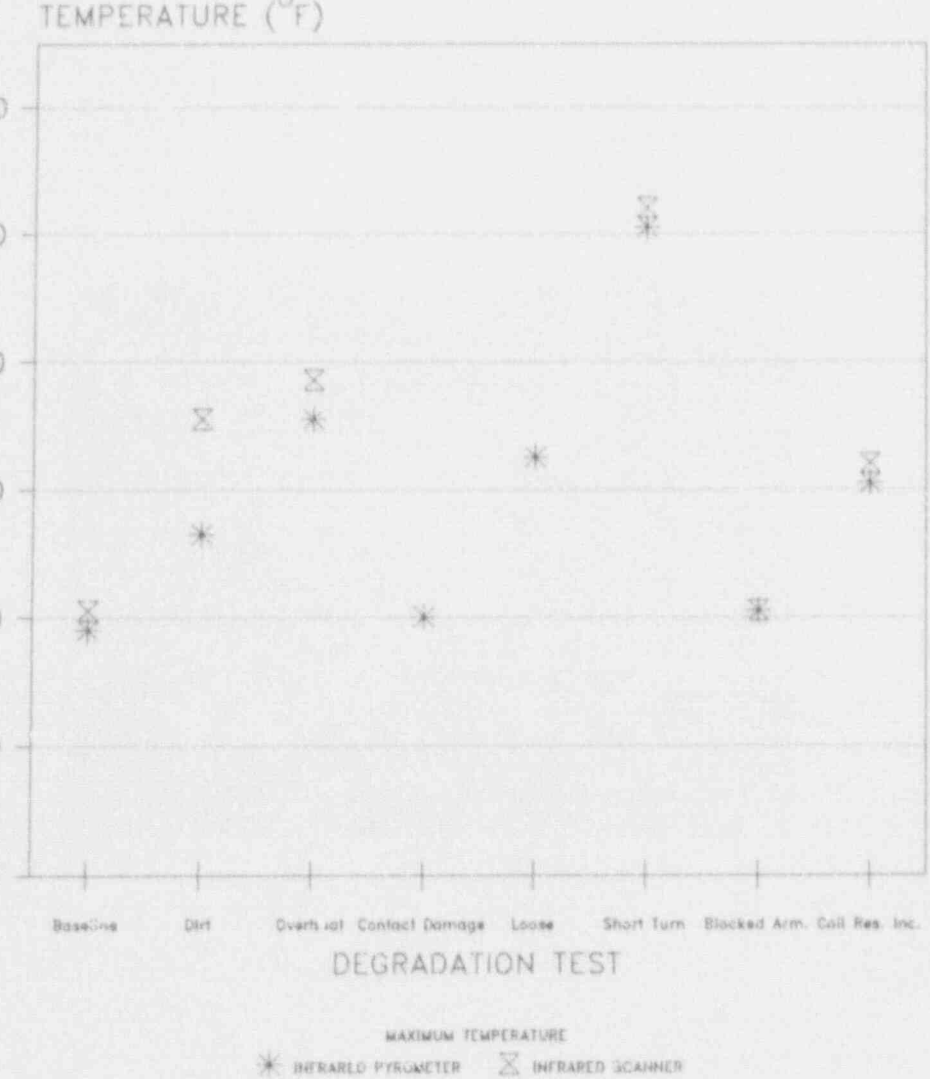


Figure 4-71. Temperature
Comparison Degradation Tests
Timing Relays

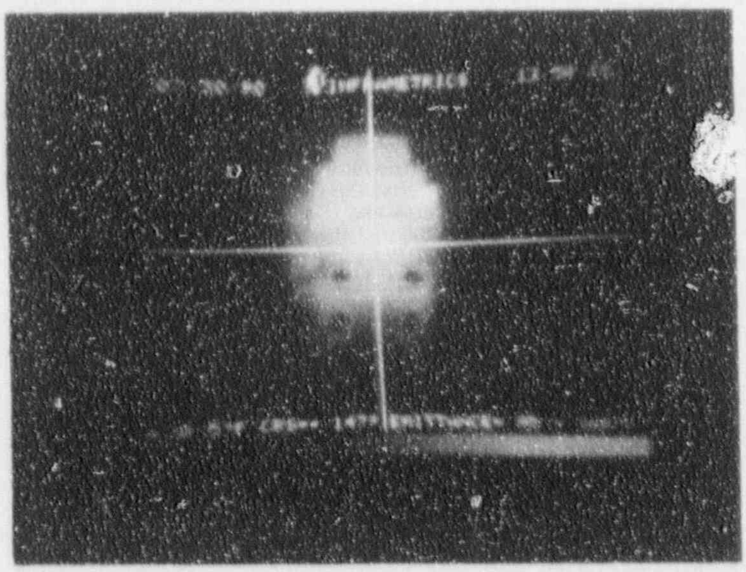


Figure 4-72. Infrared Scanning Thermograph of Timing Relay Showing Hot Spot During Overheated Degraded Condition

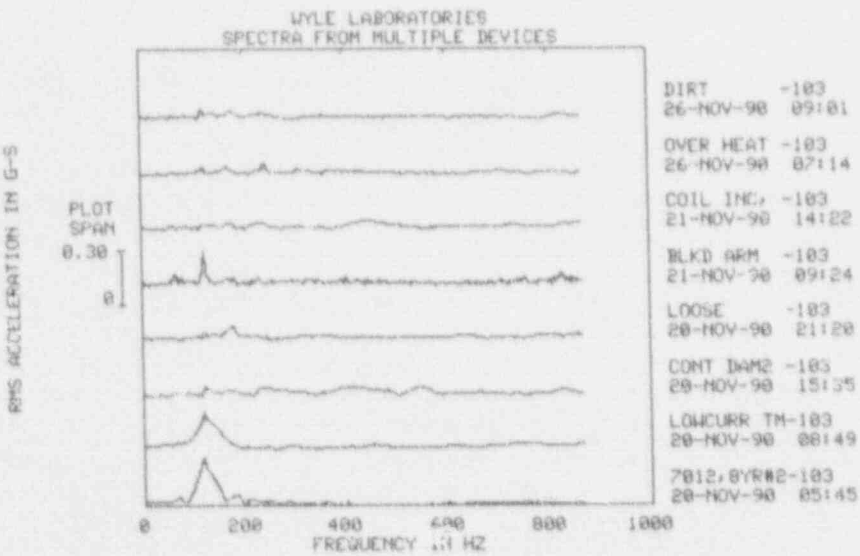


Figure 4-73. Vibration Signatures of Timing Relay During Degradation Condition Tests

4.6 Results of Degraded Conditions on Molded Case Circuit Breakers

The Square D FAL36070 was subjected to three degraded conditions and the ISM methods performed after each degraded condition. The degraded conditions were high potential tests, loose connections and dirt accumulation. The ISM methods of infrared scanning and on-contact temperature were not performed during these degradation tests on molded case circuit breakers because the equipment was unavailable at the time the tests were being performed.

Additionally, the ITE KMB2F800 was subjected to a loose connections degraded condition in order to evaluate the effectiveness of the infrared scanner, ion detection and 100% rated current hold-in methods and duplicate the history of a loose buss connection on this breaker.

The most significant findings on the molded case circuit breakers were :

- The methods of pole resistance, 135% current, instantaneous trip and vibration signatures detected all of the degraded conditions,

- Infrared thermography and visual inspection detected 67% of the degraded conditions,

- Loose connections caused the temperatures of the Square D FAL36070 to increase by 200°F and the temperatures of the ITE KMB2F800 to increase by 260°F. These temperatures exceed the temperature ratings of the materials of construction and would be expected to result in significantly reduced expected life,

- The methods of insulation resistance, mechanical actuation, 300% overcurrent, 600% overload and dielectric testing did not change due to any of the degraded conditions,

- The ion detector smoke alarms alarmed when smoke concentration was sufficiently captured in the vicinity of the alarm but did not alarm in spite of heavy visible smoke when air flow reduced smoke concentration in the immediate vicinity of the alarm.

For the Square D FAL36070 molded case circuit breaker, the ISM methods of insulation resistance, mechanical actuation, 300% overcurrent, 600% overload, and dielectric testing did not show any significant change from original baseline parameters during any of the degradation tests. Figure 4-74 shows that the 300% overcurrent method did not change significantly for any of the degraded conditions.

For the Square D FAL36070, the ISM methods which did show significant change from the original baseline parameters during at least one of the degradation tests were visual inspection, pole resistance, 100% rated current hold-in, 135% rated current hold-in, instantaneous trip, infrared pyrometry, vibration testing, acoustic testing and ion detection. For the ITE KMB2F800 circuit breaker, all of the methods, visual inspection, 100% rated current hold-in infrared pyrometry and infrared scanning, showed significant changes caused by the loose connections degraded condition. Ion detection was not effective on the ITE KMB2F800.

Visual inspection was effective in two of three degraded conditions. They were dirt accumulation and loose connections.

Pole resistance changed significantly in all three degraded conditions. Figure 4-75 shows that the pole resistance increased almost 200% due to high potential testing and loose connections and increased almost 300% due to dirt accumulation.

The 100% rated current hold-in, on the Square D FAL36070 circuit breaker, was not affected by high potential or dirt accumulation degraded conditions. However, the loose connection degradation caused the test cables to outgas and the ion detector alarmed 88 minutes into the test. The cable smoke was not visible, but the odor of burned insulation was present.

For the ITE KMB2F800 circuit breaker, the loose connection degradation caused the breaker to trip after 47 minutes at 100% rated current. Considerable smoke was generated by both the test cables and the circuit breaker prior to circuit trip.

The trip time, when 135% rated current was applied, changed in all three degraded conditions, Figure 4-76. The trip time significantly decreased after the high potential tests and slightly decreased after dirt accumulation. The loose connection degradation caused a 35% increase in trip time.

The instantaneous trip current changed significantly in all three degraded conditions, Figure 4-77. The degradations of high potential and loose connections caused a decrease in the current necessary to cause an instantaneous trip. The degraded condition of dirt accumulation caused the instantaneous trip current of pole

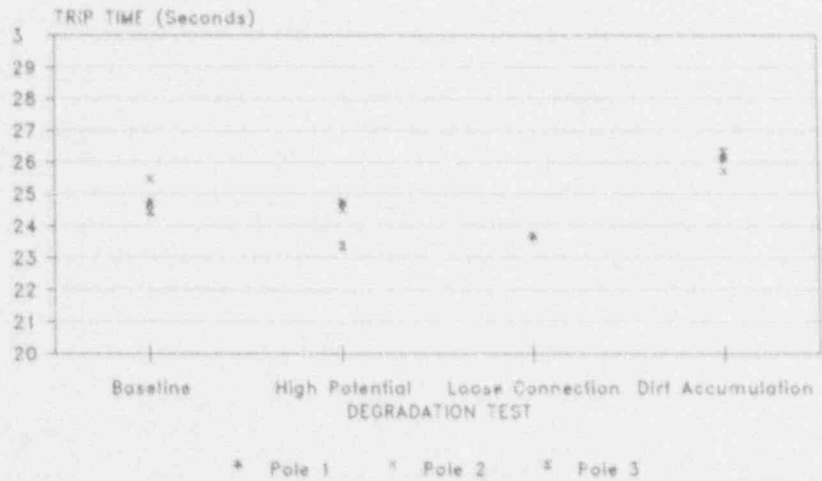


Figure 4-74. Time Delay Comparison
at 300% Overcurrent, Degradation Tests
Molded Case Circuit Breakers

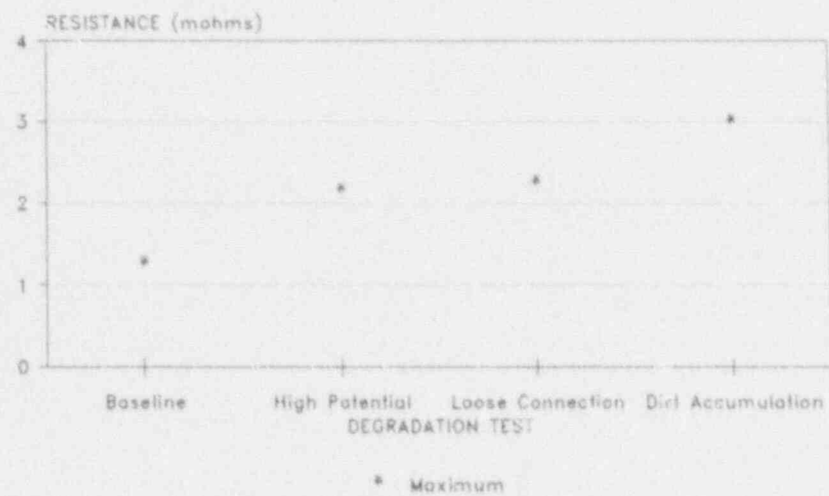


Figure 4-75. Pole Resistance
Comparison Degradation Tests
Molded Case Circuit Breakers

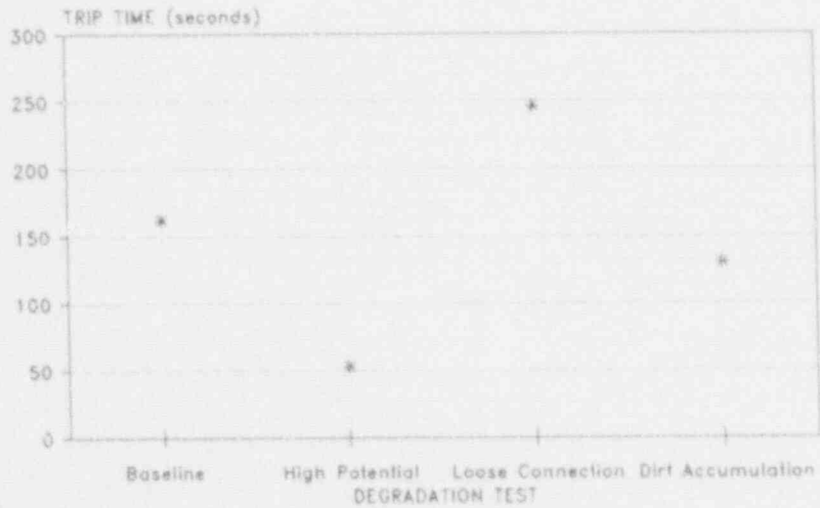


Figure 4-76. Trip Time Comparison
at 135% Rated Current, Degradation Tests
Molded Case Circuit Breakers

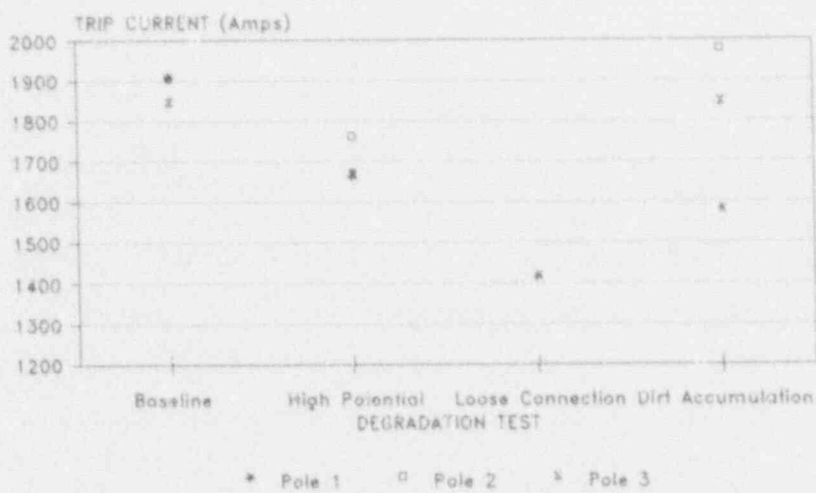


Figure 4-77. Instantaneous Trip
Comparison, Degradation Tests
Molded Case Circuit Breakers

1 to decrease, pole 2 to increase and pole 3 to effectively stay the same.

Infrared pyrometry showed temperature changes in one out of three degraded conditions, Figure 4-78, for the Square D FAL36070. An increase in temperature of almost 200°F was caused by the loose connection degraded condition. For the ITE KMB2F800 circuit breaker, the loose connection degradation caused an increase in temperature of approximately 260°F, noted by the infrared scanner and pyrometer, Figure 4-78.

Infrared scanning was available only during the degradation conditions for the ITE KMB2F800 circuit breaker. It showed the significant temperature increase, to approximately 400°F, caused by the loose connections degradation.

Vibration signature differences were caused by all three of the degraded conditions for the Square D FAL36070 molded case circuit breaker, Figure 4-79. Significant vibration signature differences were caused by the degraded condition of high potential by adding a peak at 340 Hz, by the degraded condition of loose connections by reduction in amplitude at 500 Hz and by the degraded condition of dirt accumulation by reducing the amplitude at several frequencies, most notably 203 Hz.

Acoustic signature differences were caused by all three of the degraded conditions for the Square D FAL36070 molded case circuit breaker. Very little difference in acoustic signatures were caused by the degraded condition of high potential, with the most significant difference being an added peak occurring at 1360 Hz . The degraded condition of loose connections caused the most significant differences of an additional peak at 1400 Hz, and reductions in amplitude at 800 Hz. The degraded condition of dirt accumulation caused the most significant differences in an additional peaks at 17, 90 and 1650 Hz and reduction in amplitude at 800 Hz.
No smoke or burning odors were noted during the high potential and dirt accumulation degraded conditions and the ion detector did not alarm during these degraded conditions. However, during the 100% rated current hold-in method on the loose connection degradation, smoke was generated during testing for both circuit breakers. The ion detector alarmed after 88 minutes at 100% rated current for the Square D 36070. Smoke was not visible but the odor of burnt insulation was noticed. The cable insulation at the loose connection had melted. For the ITE KMB2F800 circuit breaker, smoke was visible from both the circuit breaker and the test cable, prior

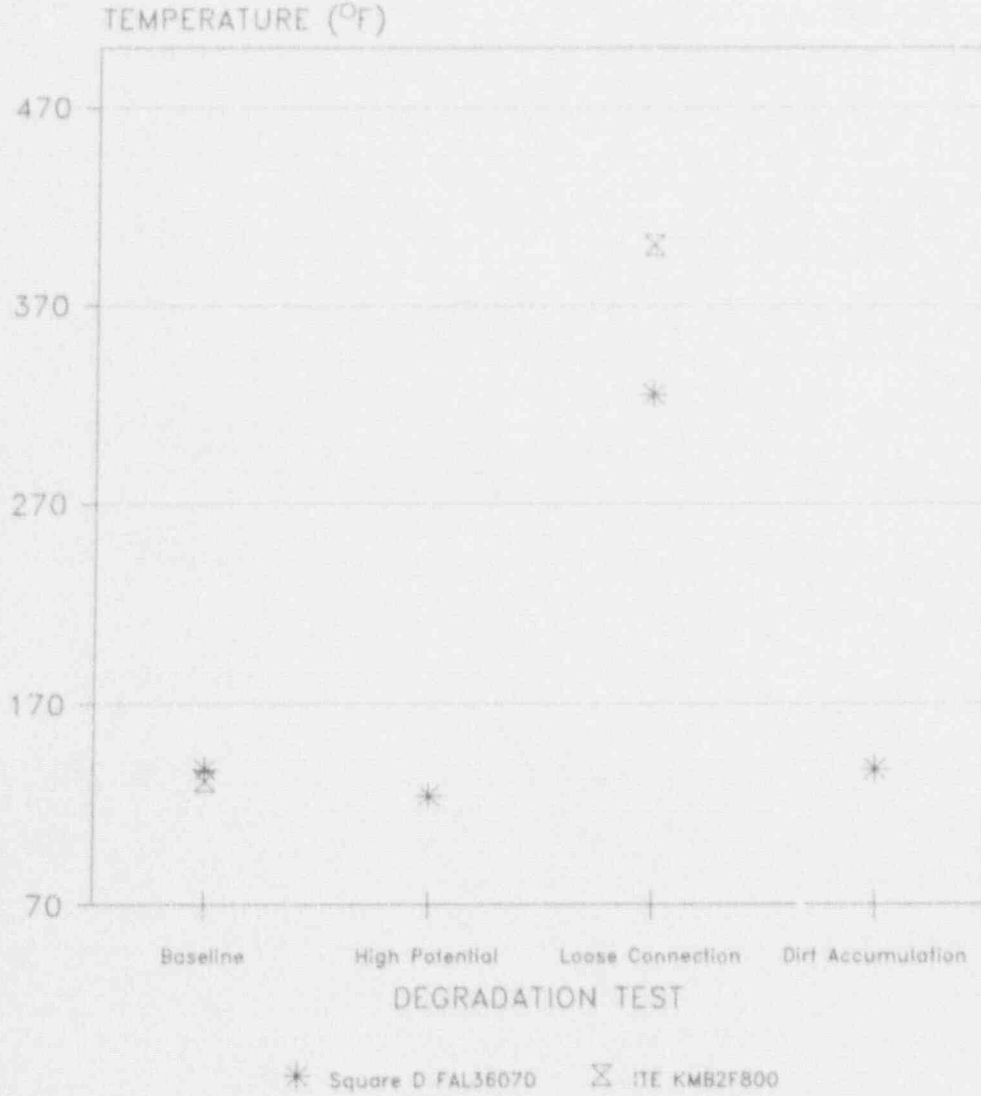


Figure 4-78. Infrared Pyrometry
Comparison Degradation Tests
Molded Case Circuit Breakers

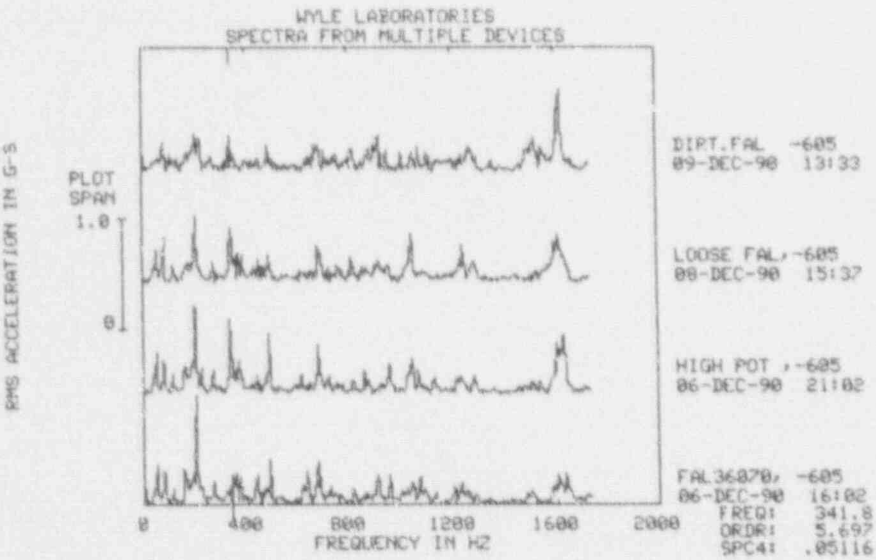


Figure 4-79. Square D FAL36070 Molded Case Circuit Breaker Vibration Signatures During Degraded Conditions

to breaker trip at 47 minutes at 100% rated current. The ion detector did not alarm.

The reason for ion detector actuation on the Square D 36070 was that the test configuration allowed the breaker to be mounted in a panel, with the ion detector above the specimen, Figure 4-80. When smoke rose, it concentrated in the top of the panel and caused the ion detector to alarm, even though the smoke was not visible.

The ITE KMB2F800 was too large to mount in the panel and accommodate the proper cable size and lengths without becoming a personnel hazard, so it was tested outside a panel, with the ion detector suspended over the breaker. Figure 4-81 shows the relative position of the ion detector, approximately six inches above the breaker. When smoke evolved from the circuit breaker and cable, air currents prevented sufficient concentration of smoke at the ion detector and the ion detector did not alarm.

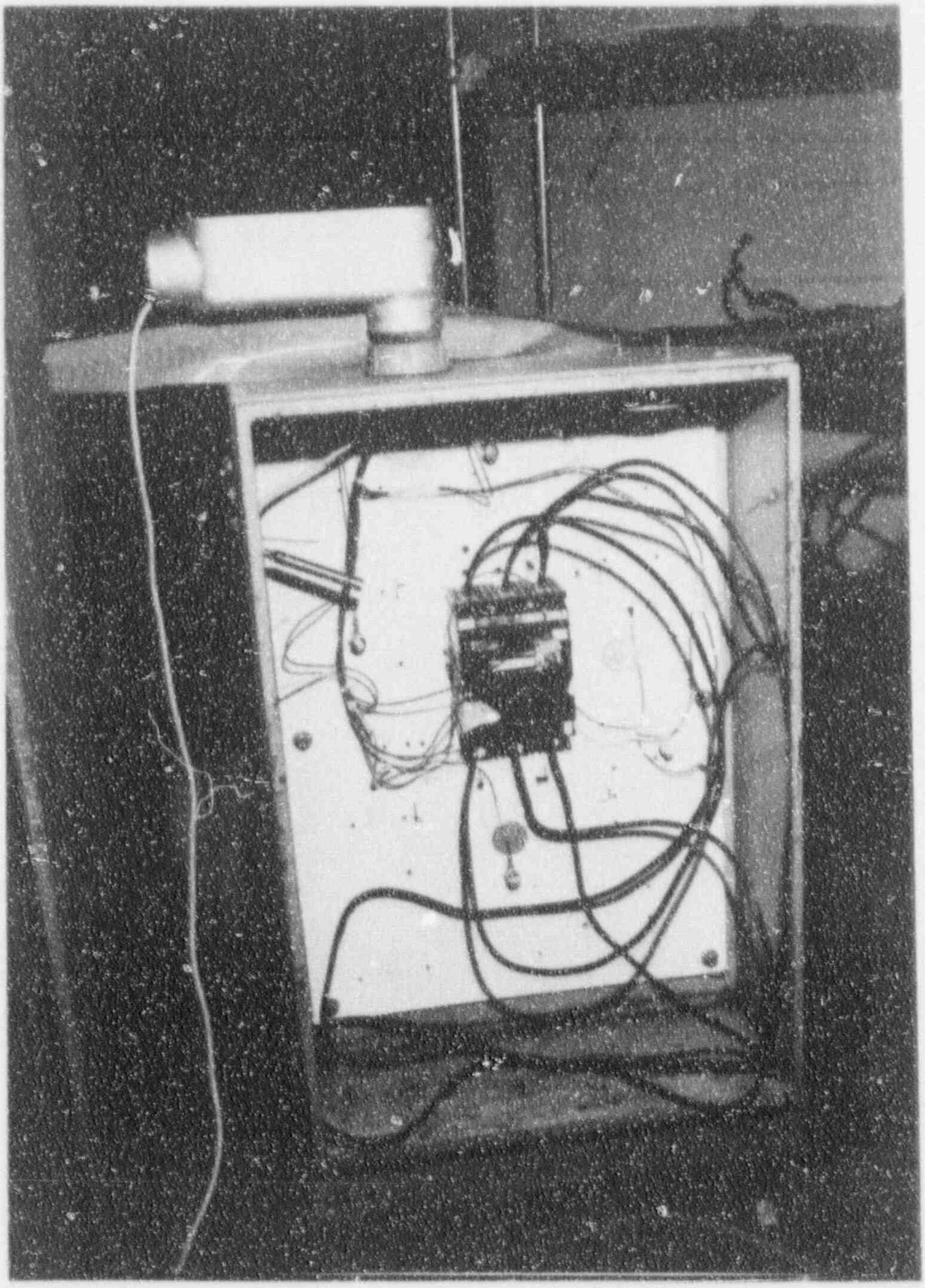


Figure 4-80. Square D FAL36070 Molded Case
Circuit Breaker During Degraded Conditions,
Note Location of Ion Detector Inside Top of Panel

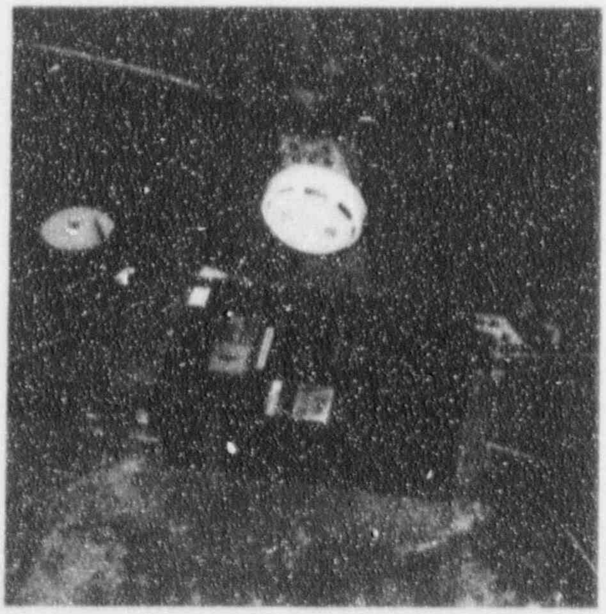


Figure 4-81. Loose Connection Degraded Condition on ITE KMB2F800 Molded Case Circuit Breaker, Note Ion Detector over Breaker

4.7 Results of Degraded Conditions on Metal Clad Circuit Breakers

The 29 year old General Electric AK-2S-25-M was subjected to five degraded conditions and the ISM methods performed after each degraded condition.

The most significant findings on the metal clad circuit breakers were:

- o The methods of visual inspection, lubrication inspection, and vibration signatures detected all of the degraded conditions,
- o The long time delay method detected 80% of the degraded conditions,
- o The methods of mechanical actuation, pole resistance, insulation resistance and short time delay trip did not change due to any of the degraded conditions.

The degraded conditions were loss of lubrication, overheated, and loose connections. Additionally, the metal clad circuit breaker was lubricated and some of the ISM methods performed to evaluate the change after lubrication. While evaluating the lubricated condition, an overload of approximate 10,000 amps was inadvertently applied to the breaker, so the impact of this degraded condition was also evaluated.

The overheated degraded condition was performed while the metal clad circuit breaker had a loss of lubricant since this constituted a worst case and was reported to be a common degraded condition by General Electric. The ISM methods of infrared scanning and on-contact temperature were not performed during these degradation tests on metal clad circuit breakers because the equipment was unavailable at the time the tests were being performed.

Loss of lubrication was accomplished by removing the existing lubricant with a degreasing cleaner. The overheated condition was accomplished by heating the metal clad circuit breaker with a heat gun until a visible sign of overheating such as discoloration had occurred. The loose connections test was performed by loosening the hold down nuts on the arc quencher retainer. The lubrication test was performed by re-lubricating the circuit breaker with GE specified grease. The overload test was performed by subjecting one pole of the circuit breaker to 10,260 amps.

The ISM techniques of pole resistance, insulation resistance, short time delay overcurrent, mechanical actuation, and ion detection did not show significant changes from original baseline parameters during any of the degraded conditions. Figure 4-82 shows the results of pole resistance. The ISM methods which did show significant change from the original baseline parameters during at least one of the degradation tests were visual inspection, long time delay overcurrent, infrared pyrometry, vibration testing, and acoustic testing.

Visual inspection was effective in all five of the degraded conditions.

Long time delay overcurrent changed significantly in four out of the five degraded conditions. They were loss of lubrication, overheat, loose connections and lubrication, Figure 4-83. The loss of lubrication caused the most significant deviation from specification and the addition of the overheated condition, while the metal clad circuit breaker had a loss of lubricant, did not worsen the long time delay overcurrent trip time. After initial lubrication, the long time delay overcurrent trip time improved and came back into specification. The result that it returned to near baseline conditions after the overload degraded condition was attributed to the fact that it had seen more operations since it had been lubricated and this had a bigger impact than the overloaded degradation.

Infrared pyrometry showed temperature changes in one out of five degraded conditions, Figure 4-84. The overheated condition caused an increase of $30^{o}F$ to the EC-1 series overcurrent trip devices.

Vibration signature differences were caused by all three of the degraded conditions for the GE AK-2S-25-M metal clad circuit breaker, Figure 4-85. Significant vibration signature differences were caused by the degraded condition of loss of lubricant by adding peaks at 180 Hz and below and between 1430 and 1950 Hz, as well as a change in the spectrum at 530 Hz. The degraded condition of overheat caused additional peaks at 730 to 780 Hz. The loose connections degradation caused additional vibration from approximately 1500 to 2400 Hz.

The time history of the vibration signatures also exhibited changes caused by the degraded conditions. Figure 4-86 shows the time history vibration signatures for the AK-2S-25-M breaker in the as received condition and after the degraded conditions. The as received condition is on the bottom and in ascending order, the degraded conditions of loss of lubrication, overheated and loose connections. Significant differences were noted in the number of peaks, highest amplitude and time between peaks. For instance the number of peaks which exceed 6 g were 12, 32, 13 and 24 for the

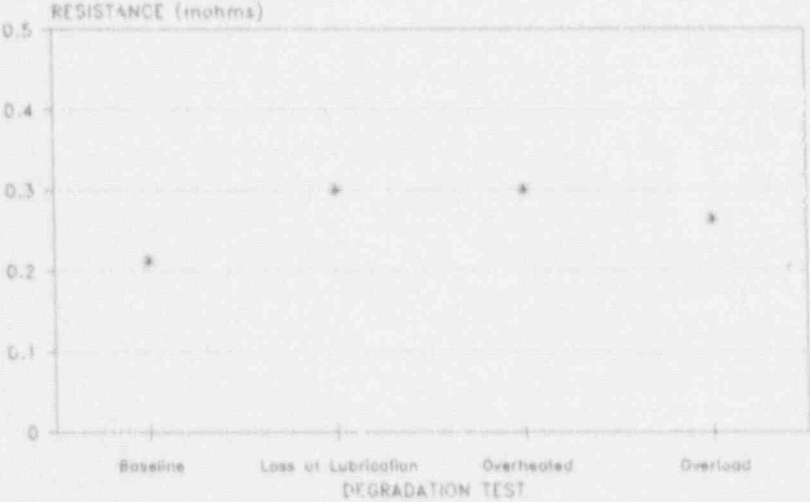


Figure 4-82. Pole Resistance Comparison Degradation Tests Metal Clad Circuit Breakers

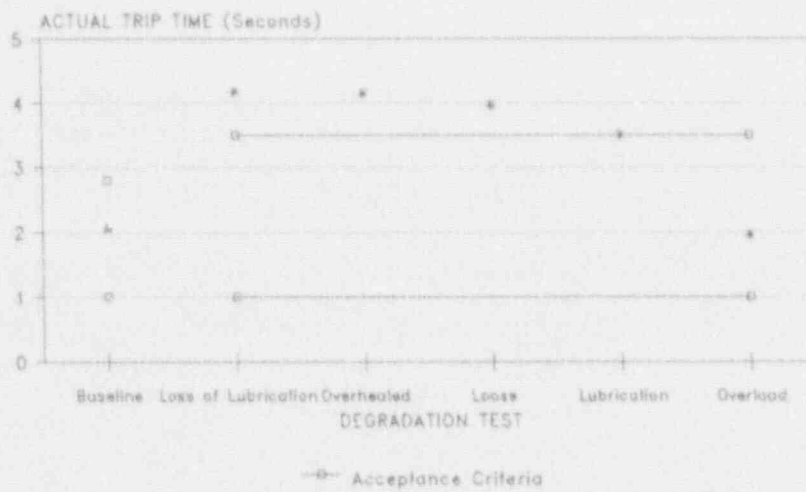
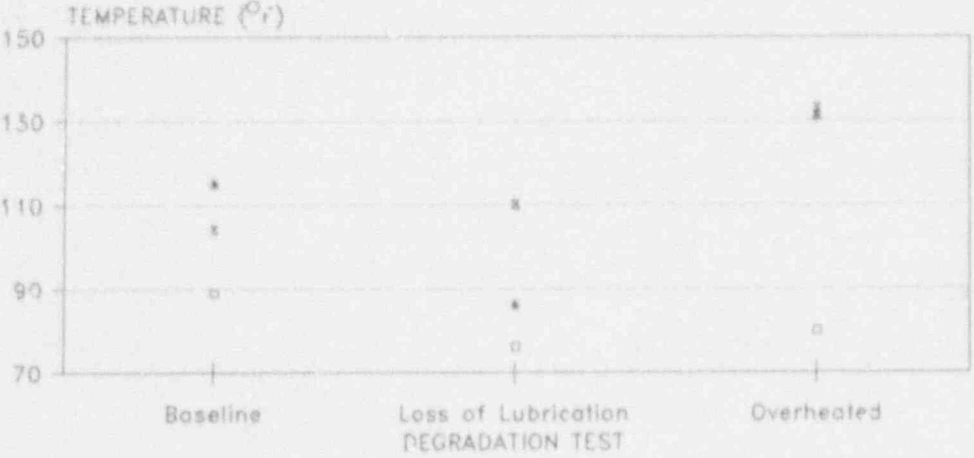


Figure 4-83. Long Time Delay Overcurrent Comparison Degradation Tests, Metal Clad Circuit Breaker



Angle of View:

* Left 45 ▫ 90 x Right 45

Figure 4-84. Infrared Pyrometry
Comparison Degradation Tests
Metal Clad Circuit Breaker

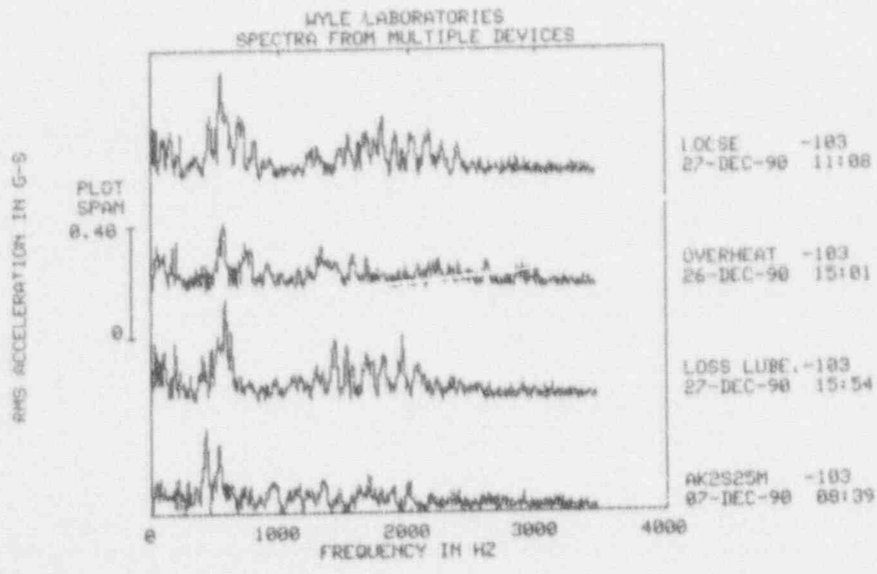


Figure 4-85. Vibration Signatures of Metal
Clad Circuit Breakers During Degraded Conditions

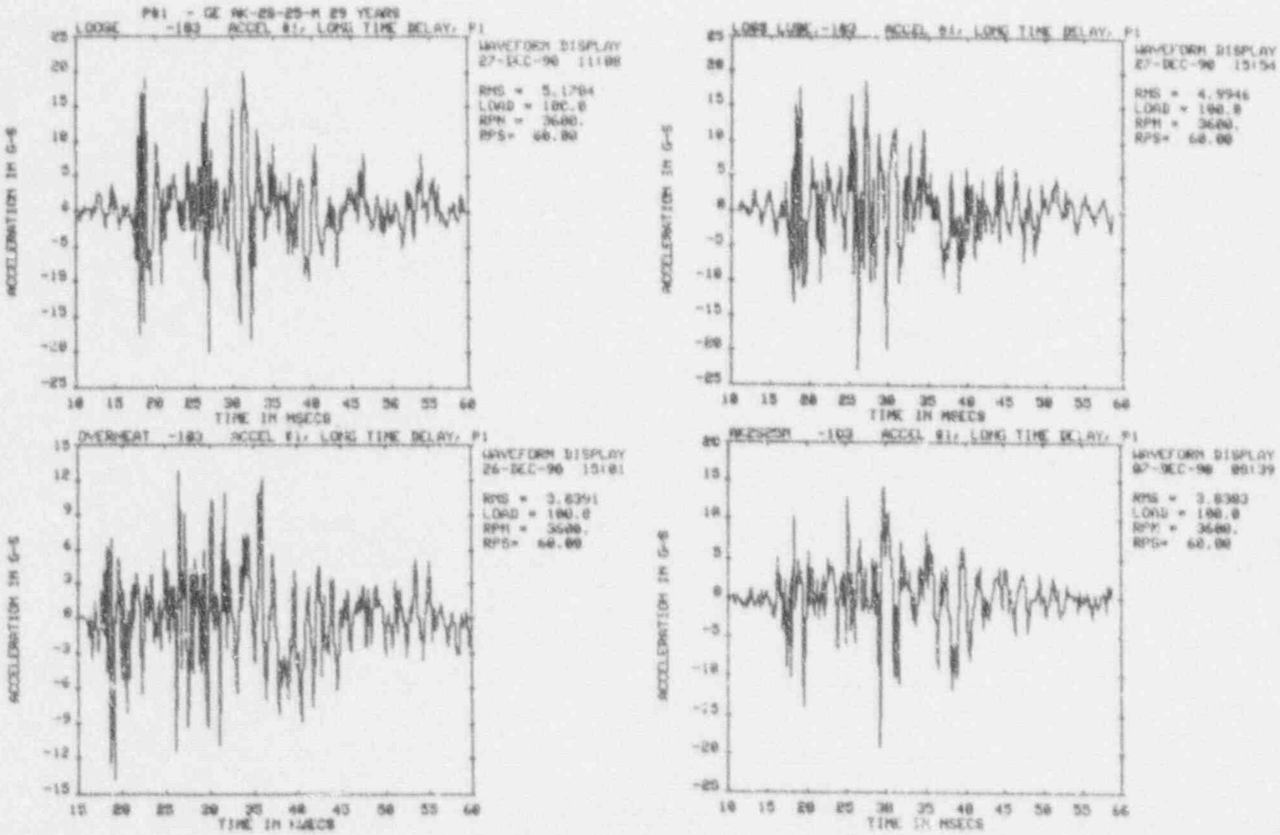


Figure 4-86. Vibration Time History Signatures of Metal Clad Circuit Breakers During Degraded Conditions

conditions , as received, loss of lubricant, overheated, and loose connections, respectively, Figure 4-87. Increases in the maximum amplitude were caused by the degraded conditions of loss of lubrication and loose connections, Figure 4-88, and the timing between the first through fourth highest peaks was most effected by the degraded condition of overheated, Figure 4-89.

Acoustic signature differences were caused by the loss of lubrication and overheat degraded conditions. Data was not available on the loose connection due to equipment problems. The most significant differences were in the frequencies of 500 to 600 and 900 to 1100 Hz and the addition of peaks at 2700 and 3000 Hz by the degraded conditions.

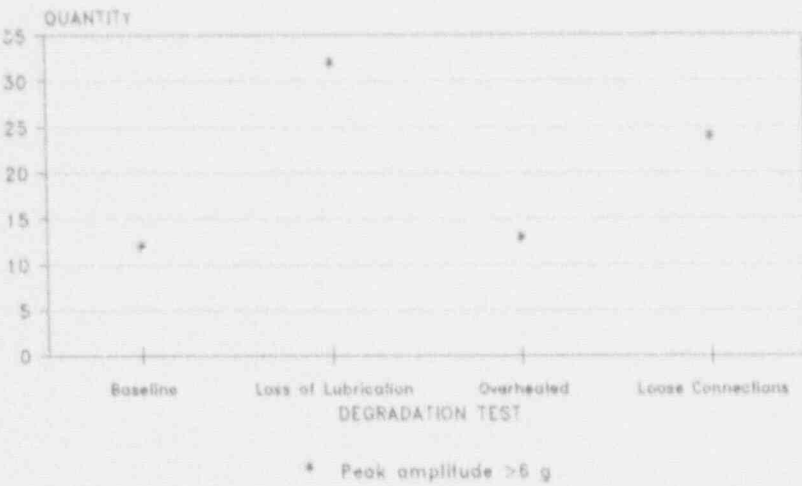


Figure 4-87. Analysis of Vibration
Signatures, Quantity of Peaks
Metal Clad Circuit Breakers

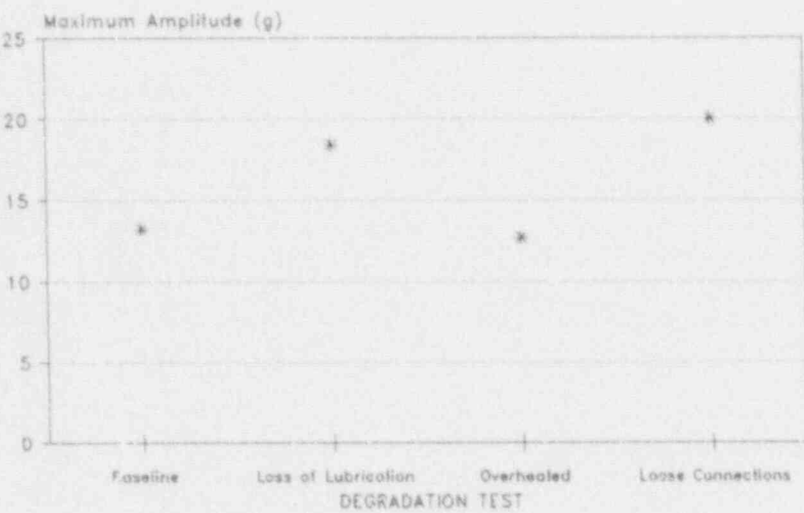


Figure 4-88. Analysis of Vibration
Signatures, Maximum Amplitude
Metal Clad Circuit Breakers

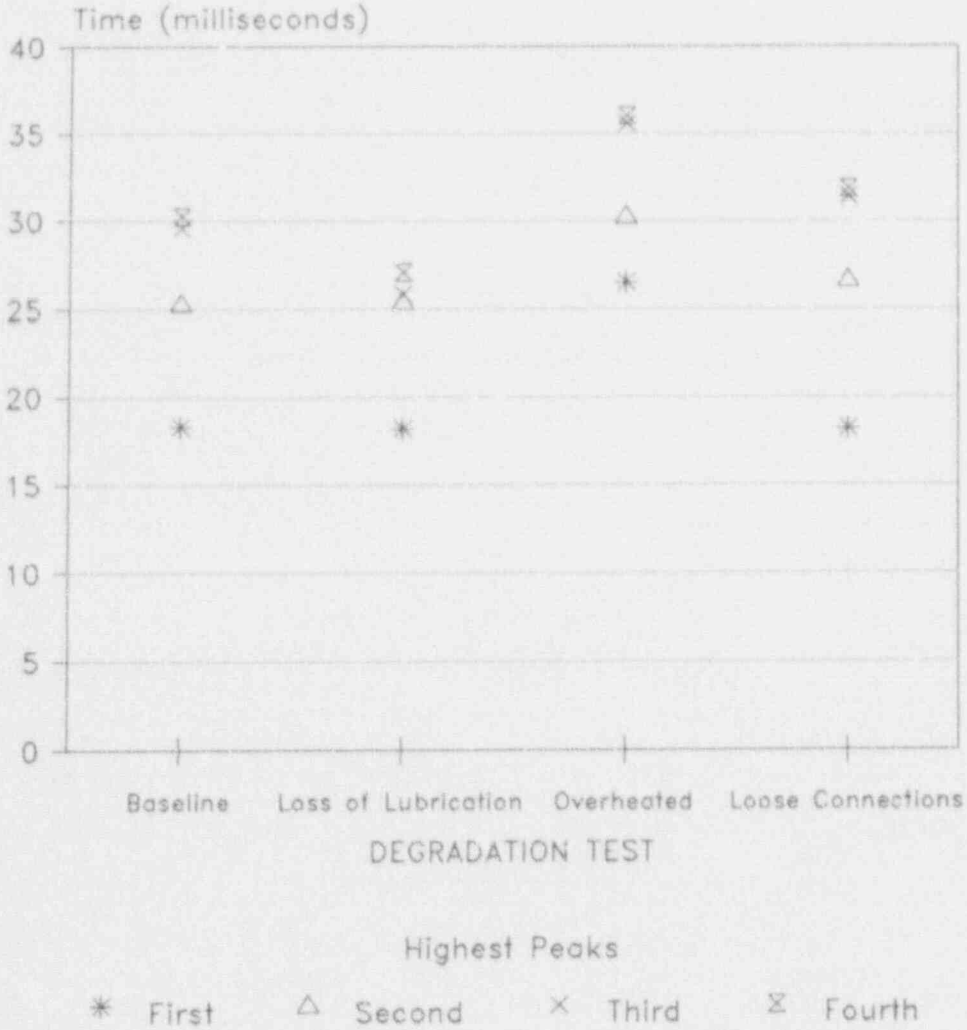


Figure 4-89. Analysis of Vibration Signatures, Timing Between Peaks Metal Clad Circuit Breakers

4.0 In-situ Efforts

The In-situ efforts were performed on relays and circuit breakers at two operating nuclear plants. The plants were Duke Power Company's Catawba Nuclear Station and Niagara Mohawk Power Corporation's Nine Mile Point Unit 1 Nuclear Plant. The maintenance engineering and operations staff at both facilities were extremely knowledgeable. No problems were found on equipment evaluated.

The elements of the in-situ efforts were three fold. First, plant maintenance personnel were observed while they performed routine plant maintenance on relays and circuit breakers. Second, plant procedures for inspection, testing and maintenance of relays and circuit breakers were obtained, results of plant maintenance tests were reviewed, and engineering and maintenance personnel were interviewed. Third, non-intrusive ISM methods of infrared pyrometry, infrared scanning and vibration testing were demonstrated to the plant personnel and data taken on installed relays and circuit breakers in order to determine the practicability of the methods in nuclear plants.

The in-situ efforts provided valuable insight into the routine relay and circuit breaker inspections, surveillance and monitoring methods currently in use. The practicability of the infrared pyrometer, infrared scanning and vibration testing methods were proven. These methods had the advantages that the equipment was small, lightweight and easily portable. An additional advantage was that the equipment allowed data acquisition in the plant and detailed analysis of the data outside of the plant in engineering offices. This shortened the length of time in the plant.

In this section the results of the tests witnessed, records reviewed and tests performed at each plant are summarized.

Nine Mile Point Unit 1 Nuclear Plant

The in-situ efforts at Nine Mile Point concentrated on 4 KV power boards located in the auxiliary building. These power boards were operational and contained General Electric Magne-Blast Type AM-4 16-350-1H, 4 KV Métal Clad circuit breakers, GE 12IAC protective relays and GE 12HFA auxiliary relays. The 4 KV circuit breakers were evaluated in the in-situ efforts because specimens were not available for the tests on aged devices or the degradation tests because of the cost and availability of this type of circuit breaker.

Six 4 KV breakers, three IAC and three HFA relays were evaluated. The ISM techniques of infrared pyrometry, infrared scanning and vibration testing were performed. No problems were found on any equipment. The vibration testing was accomplished in the quiescent operational state. Infrared pyrometry was obtained with a Rayteck Ranger Pyrometer and the infrared scanning was accomplished with an AGEMA 470 Infrared System. Figure 4-90 shows one of the GE Magne-Blast 4KV circuit breakers. The breaker was manufactured in January 1966

The results of the infrared pyrometry, which were the same as the infrared scanner are shown in Figure 4-91. The external temperatures on the power boards were all at the same temperature. The corresponding current in each breaker was 0 amps for Power Board H22-R125 Breaker, 25 amps for the Auxiliary Feeder 12-R124 Breaker, 56 amps for the Turbine Building Cooling Water Pump No. 12 Breaker, 80 amps for the Reactor Re-circulation Pump Motor Generator No. 15 Breaker, 210 amps for the Condenser Circulating Water Pump No. 12 Breaker and 1000 amps for the Clean-up Pump No. 12 Breaker.

The doors of two power boards were opened by Niagara Mohawk electricians so that infrared temperatures and vibration signatures could be obtained directly from the circuit breakers. The vibration signatures were obtained while the breakers were in their closed condition. Figure 4-92 shows the use of the infrared pyrometer on one of the 4 KV metal clad circuit breakers. The inside temperature on the Clean-up Pump No. 12 Breaker was approximately 15°F hotter than outside since the current in the breaker was approximately 1000 amps. All circuit breakers were operating near the same temperature regardless of the current. No significant changes in temperatures were observed. The circuit breakers and relays were clean and had no obvious problems.

According to Niagara Mohawk procedures, preventive maintenance is performed on the 4KV metal clad circuit breakers after each plant cycle for the safety-related circuit breakers which are in operation during normal plant conditions. Safety-related breakers which are operational only during an outage have a maintenance interval of two cycles and the remainder are maintained at three cycle intervals.

Figure 4-93 shows the Niagara Mohawk electrician assisting in the vibration data acquisition. The vibration data was acquired with a hand held data acquisition computer. This computer was able to acquire and store several vibration signatures. The signature was displayed on the screen of the computer and data then transferred and reduced at the host computer after completion of the in-situ efforts.

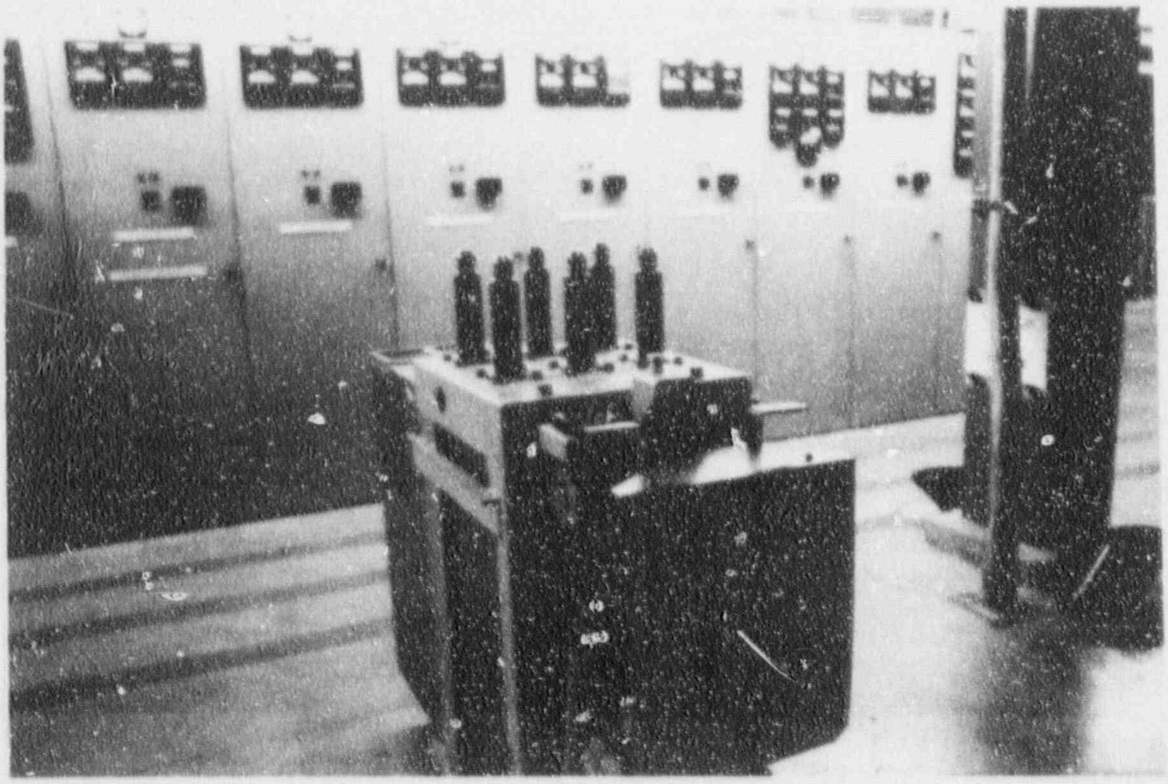


Figure 4-90. GE Magne-Blast
4KV Metal Clad Circuit Breaker
at Nine Mile Point Unit 1.

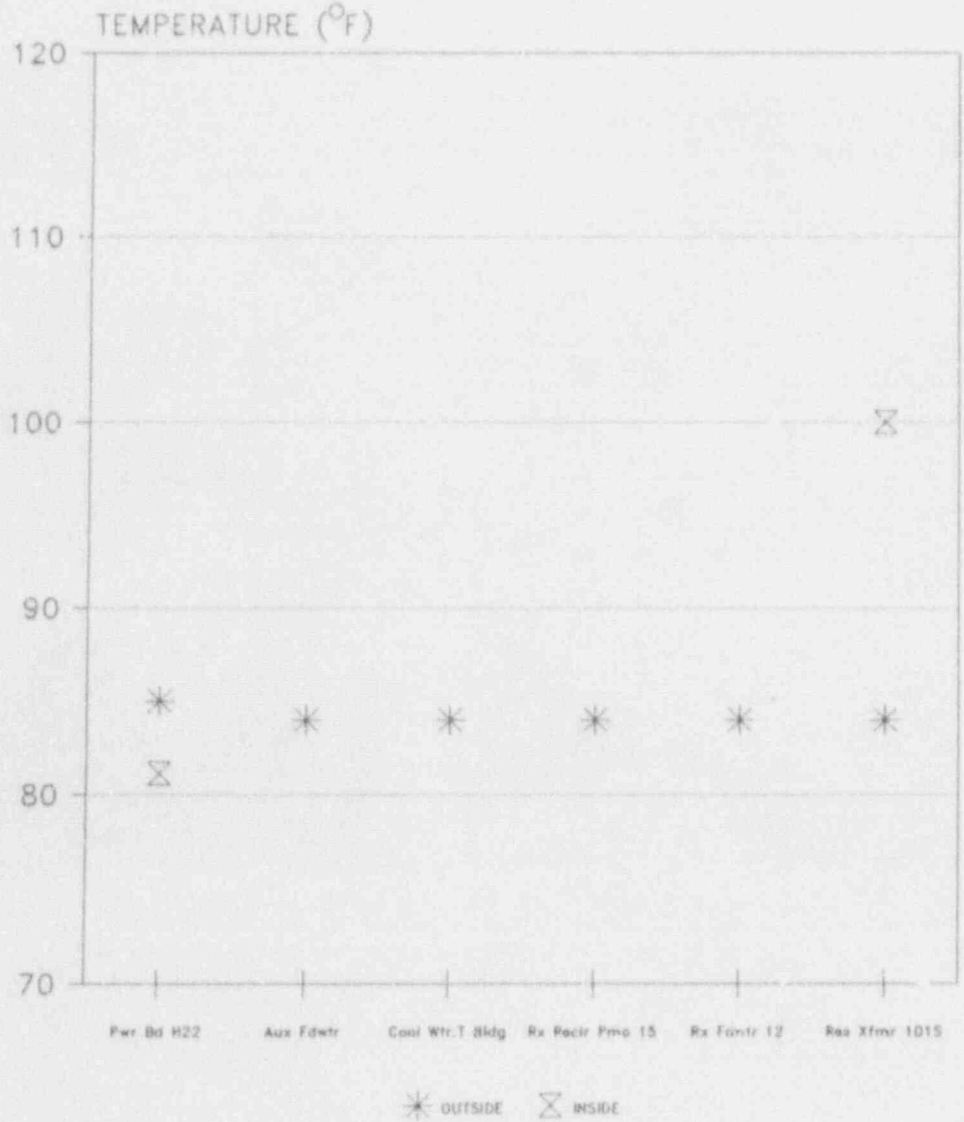


Figure 4-91. Infrared Pyrometer
Nine Mile Point 1 Power Boards

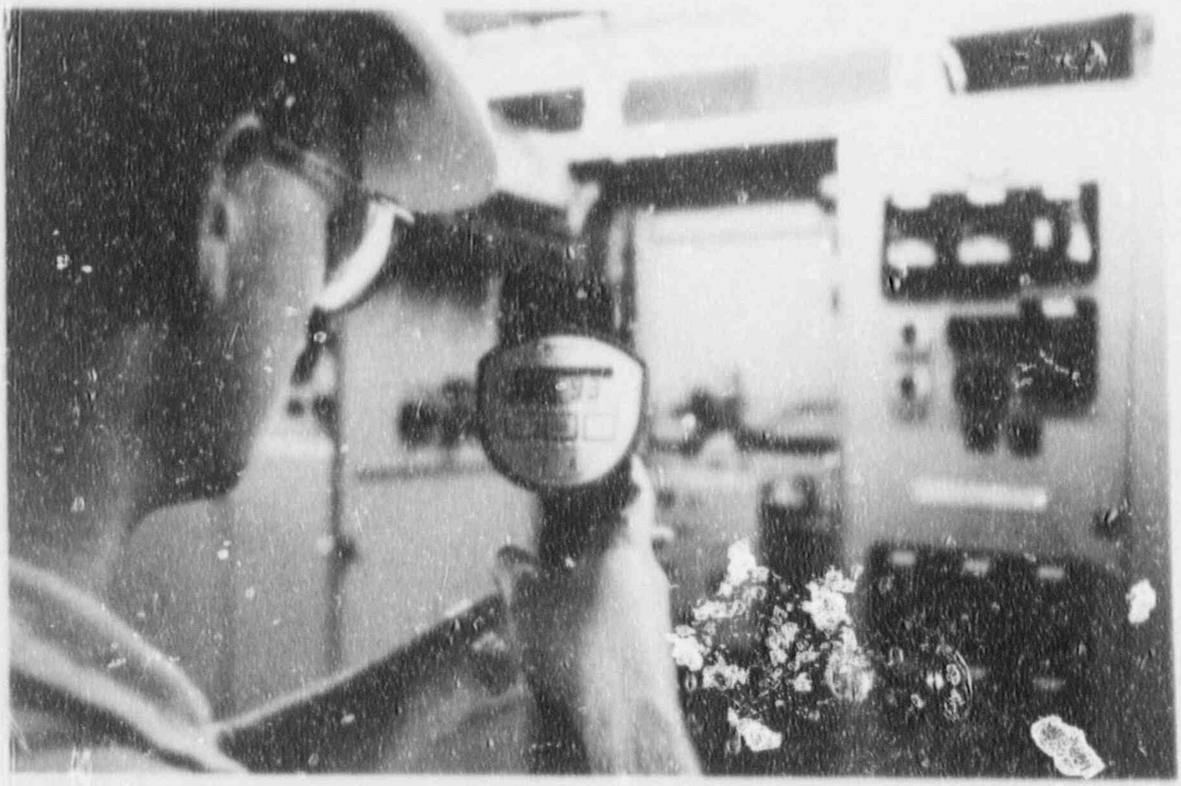


Figure 4-92. Temperature Measurement of 4KV Metal Clad Circuit Breaker at Nine Mile Point Unit 1 with Hand Held Pyrometer

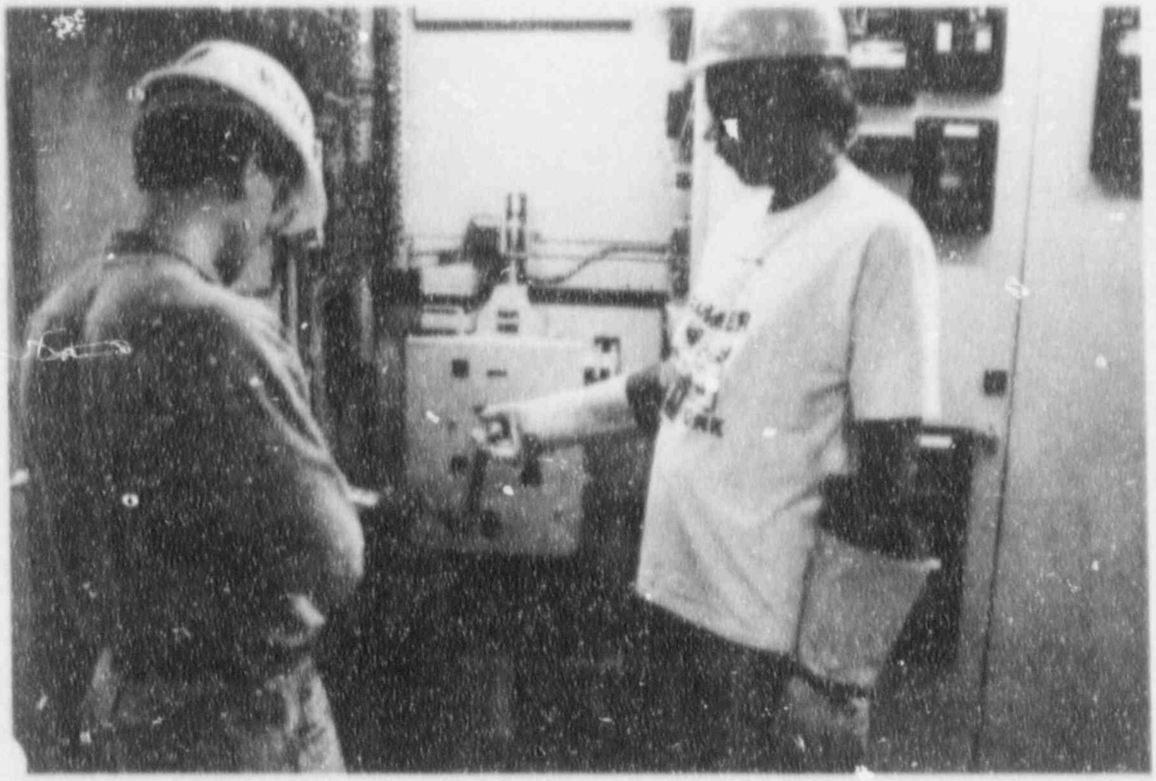


Figure 4-93. Vibration Monitoring of 4KV
Metal Clad Circuit Breakers
at Nine Mile Point Unit 1

Catawba Nuclear Station

Plant personnel were observed performing inspection and surveillances on molded case circuit breakers in motor control centers (MCC). The procedures required the disconnection of the wiring to the breakers so that a 300% overload test could be performed on the breakers. Figure 4-94 shows the Catawba electrician disconnecting and tagging the leads. After the trip tests were performed, the leads were attached and voltages measured to assure proper connections, Figure 4-95.

Pick-up and drop out voltage tests of control relays were observed. In order to perform pick-up and drop out voltage tests, it was necessary to disconnect the relay from the circuit. The test set used at Catawba was designed to be portable and contained a variable power supply, volt meter and timing circuit. Test blocks had been installed in the circuits of relays which were tested monthly for pick-up and drop out voltage in order to facilitate the testing. This made connecting and disconnecting the relays an effortless process as compared to that required when testing the molded case circuit breakers. Figure 4-96 shows the Catawba staff testing pick-up and drop out voltage on relays in the diesel generator sequencing panel. These relays were tested at monthly intervals. The connections to the test blocks and the infrared scanning, which was performed during the pick-up and drop out voltage tests, were also evident.

The results of pick-up and drop out voltage tests are shown in Figure 4-97. No problems were noted during these tests.

The Catawba maintenance staff had discovered a problem with Westinghouse Molded Case Circuit Breakers. The model was Type HFB 3125, which was an ambient compensated 125 amp breaker. This problem was discussed with the in-situ team. It had occurred prior to the in-situ effort.

An HFB 3125 molded case circuit breaker was tripping on instantaneous trip outside of the manufacturer's published trip curve. The problem was originally found and reported by Duke Power Company's Catawba Nuclear Plant. Once verified by Westinghouse, Westinghouse notified Duke Power Company of a 10CFR Part 21 concerning Ambient Compensated Molded Case Circuit Breakers. The purpose of the notification was to inform Duke Power Company that specific electrical confirmatory tests had not been performed for the magnetic (instantaneous) trip portion of the breaker. Westinghouse stated that the magnetic pick-up band was unknown. It was reported that the ambient compensating design had a lower latch load resulting in possible lower magnetic tripping, but actual

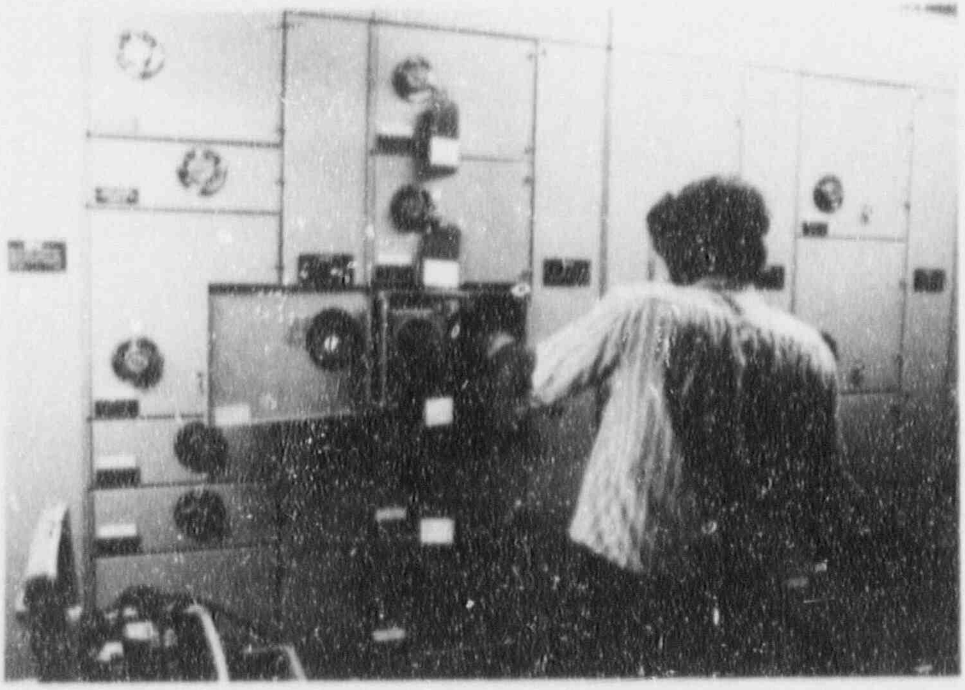


Figure 4-94. Disconnecting Leads
of Molded Case Circuit Breakers Prior to
300% Overload Trip Test at Catawba Nuclear Station

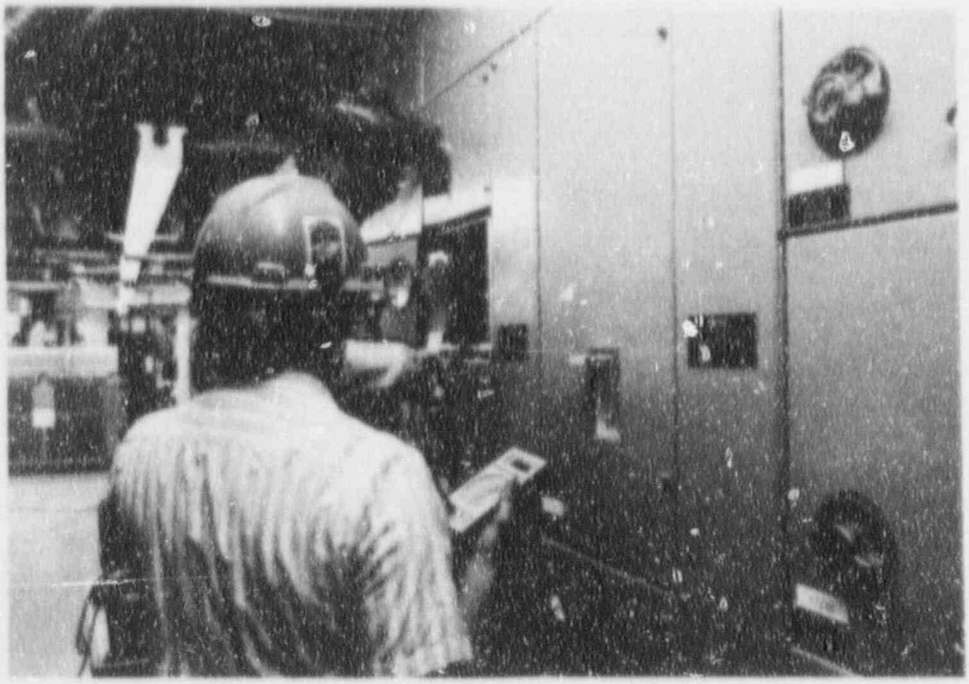


Figure 4-95. Testing of Molded Case
Circuit Breakers at Catawba Nuclear Station

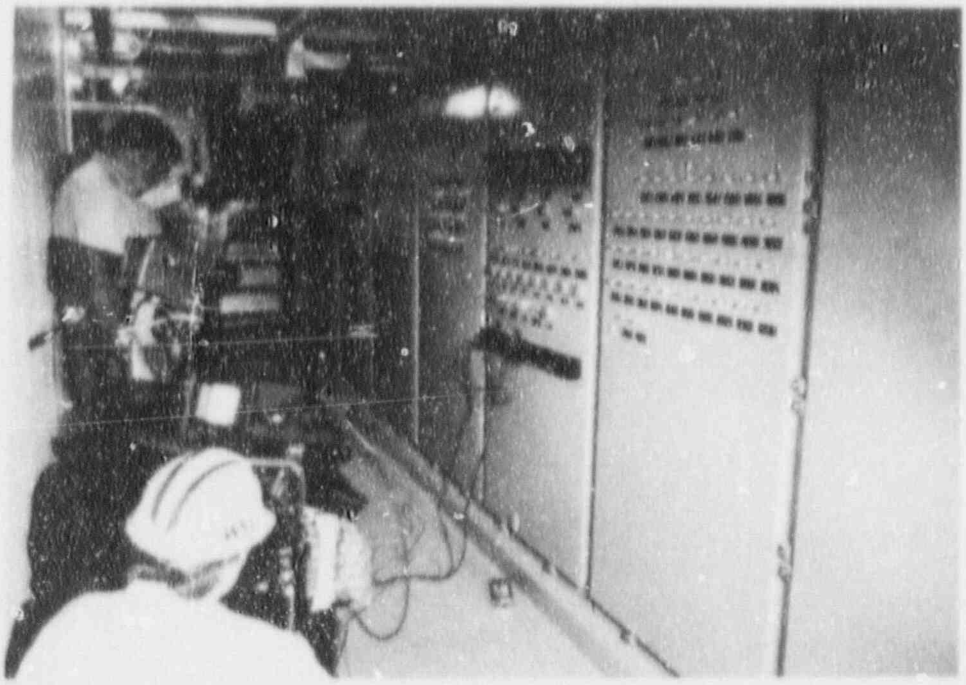


Figure 4-96. Pick-up Voltage Testing and
Infrared Temperature Measurement with
AGEMA Thermovision 870 Infrared Scanner at Catawba

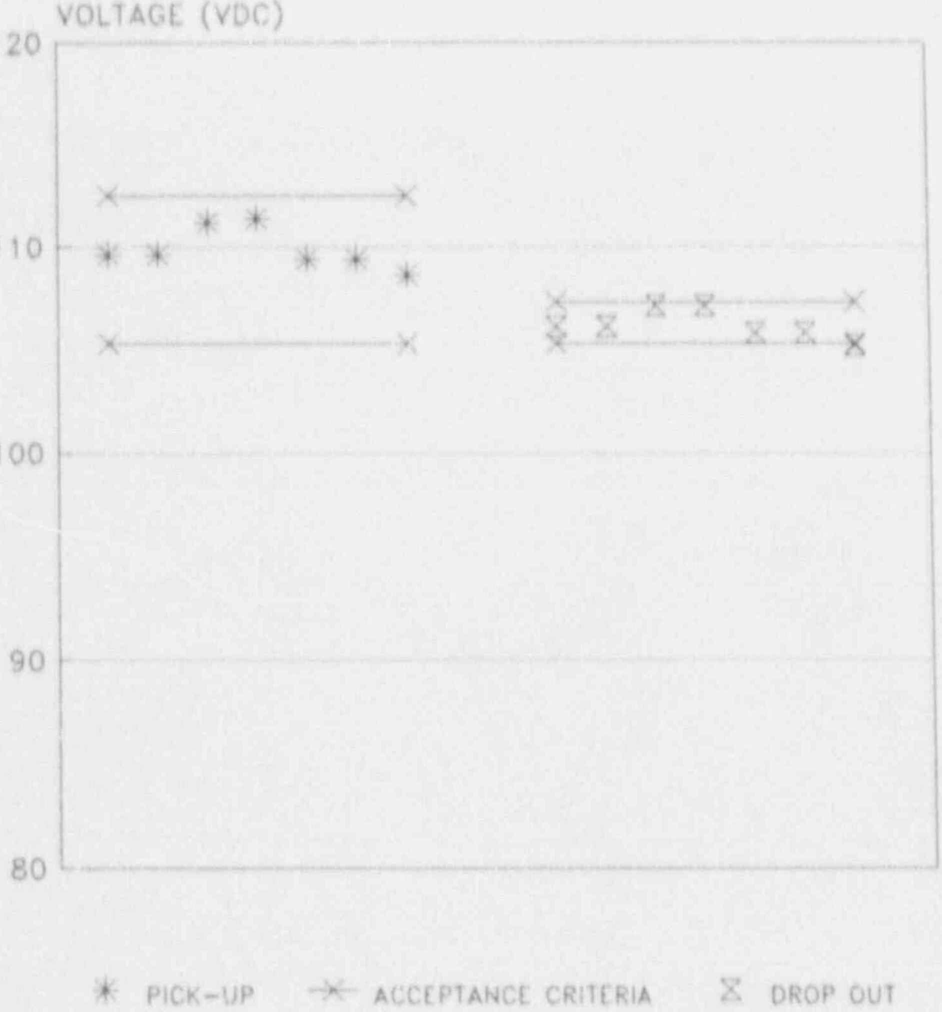


Figure 4-97. Pickup & Drop Out Voltage
Comparison Control Relays
At Catawba Nuclear Station

values were unknown, as they had never been tested and recorded. According to Duke Power Company engineers, Westinghouse had requested that the literature be revised to document that the 125 Amp ambient compensated breaker was no longer available.

Duke Power's Company's procedure for in plant testing of molded case circuit breakers required a test at 300% of rating. According to the manufacturer's trip curve, the 300% point was in the non-instantaneous portion of the trip curve. The circuit breaker apparently worked properly at the 300% point and the breaker was returned to service.

Some time later, when a system test was performed, the problem first manifested itself. When the Hydrogen Skimmer Fan was started, the HFB 3125 Circuit Breaker tripped. Apparently the inrush current of the fan was high enough to cause an instantaneous trip.

A failed circuit breaker was sent to a commercial test facility for testing to NRC Bulletin 88-10 requirements. The test facility tested the circuit breaker and concluded that it had passed.

The requirement from NRCB 88-10 for Instantaneous Trip Test was:

> "2.5.1 : Fixed Instantaneous Setting CBs. Each pole of the CB should be tested for pickup of the instantaneous unit. Each pole must be between 75% and 125% of the instantaneous trip rating. The trip time should not exceed 0.1 seconds (6 cycles)."

The test record documents that each pole of the circuit breaker was tested at one point, approximately 1000 Amps, which was the 800% current point for this 125 amp breaker. The breaker did instantaneously trip at this point.

The original published trip curve from Westinghouse showed that the low side of the instantaneous trip should be approximately 550%.

Testing for instantaneous trip at only one point does not prove that the breaker does not instantaneously trip at a point less than the manufacturer's curve. In Phase II, each pole of molded case circuit breakers were tested at 75% of the lower instantaneous trip curve and at 125% of the upper trip curve. The breaker should not instantaneously trip at the 75% value, i.e., the trip time should be greater than the manufacturer's specification, typically greater than 0.1 seconds. Conversely, it should instantaneously trip at the 125% point of the upper trip curve. This assured that an instantaneous trip occurred between 75% and 125% of the instantaneous rating.

Testing a circuit breaker for instantaneous trip should be accomplished by either of the following methods: Tests below and above the instantaneous trip rating or the short pulse tests method.

When two tests are performed, one is below the instantaneous trip range and one is above the instantaneous trip range. For instance, the trip time, at a current of 75% of the instantaneous current trip rating, should not be instantaneously. The trip time, at a current of 125% of the instantaneous current trip rating, should be instantaneous.

When the short pulse method is performed, short (5 to 10 cycles) pulses of current are applied to the breaker during multiple tests. The first pulses start out below the instantaneous trip rating and are increased gradually until the breaker trips instantaneously. The current causing an instantaneous trip would be compared to the trip rating to verify that it is within the instantaneous range.

For molded case circuit breakers which have adjustable instantaneous trip bands, testing should include tests below and above the lowest magnetic trip setting and below and above the highest magnetic trip setting. During the tests on aged devices, a molded case circuit breaker tripped properly at the low setting of the instantaneous trip range and failed to trip when adjusted to the high setting. The root cause, as noted in section 4.6, was age related.

The Catawba staff had also found an age related problem with Sylvania relays. The application of the relay was in a starter circuit as a contactor for a molded case circuit breaker in a motor control center. The root cause of the failure was loosening of the contact carrier screws during normal operation. The screws had vibrated loose and caused the contact carrier on one relay to fall off of the relay. Infrared pyrometry was used to scan other suspect relays and the contact carrier of another relay was found to be loose. One of the two screws had disengaged from the contact carrier and had dropped to the bottom of the MCC.

The Catawba staff then inspected 35 MCCs which contained 7 to 60 of the suspect relays and found 28 with loose screws. The corrective action was to change out the original screws with self locking screws which had a nylon patch applied to the screw to preclude the screw from loosening. Figure 4-98 shows the relay and the new screw.

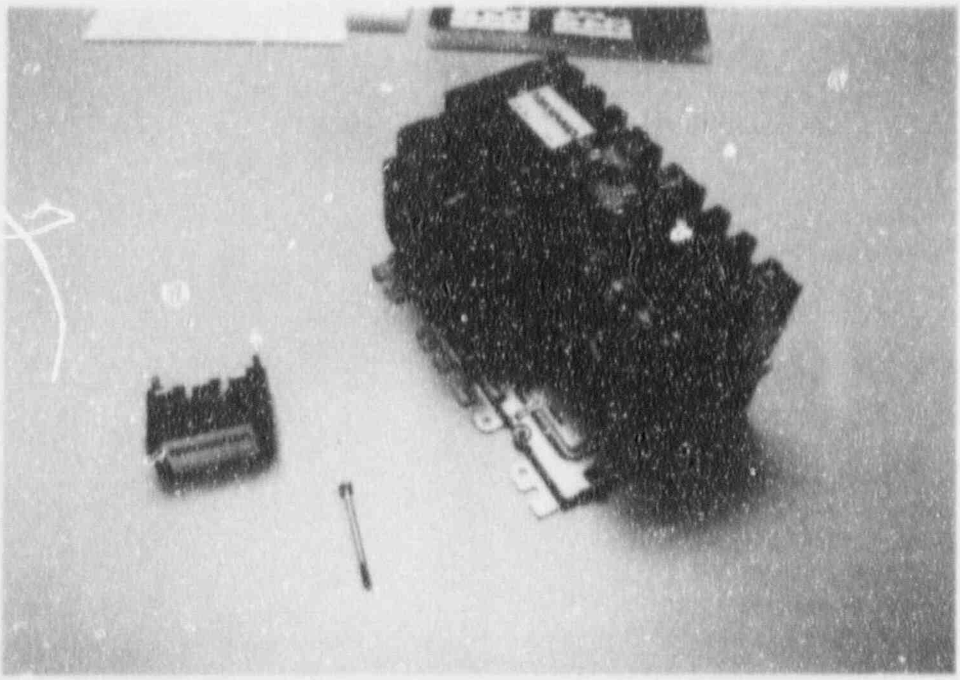


Figure 4-98. Sylvania Relay Showing Contact Carrier and Self-Locking Screw with Nylon Patch

5. USEFUL MONITORING METHODS

In this section, current nuclear practice for inspection, surveillance and monitoring of relays and circuit breakers was evaluated to determine its effectiveness to detect and potentially mitigate aging. Changes to current practice are recommended when more effective methods to detect and potentially mitigate aging were determined by the Phase II research.

The evaluations of current nuclear practice and the effectiveness of the ISM methods tested in Phase II are summarized in Table 5-1 and presented for each type of relay and circuit breaker evaluated in Phase II.

Some of the significant general observations are as follows:

- o Out of 29 degraded conditions simulated for relays, the most common industry ISM method of pick-up voltage correctly detected 3, did not change on 20 and provided misleading results on 6,

- o Out of all of the degraded conditions simulated for relays and circuit breakers, Table 5-1 shows that the ISM methods detecting the most were vibration signatures, visual inspection, acoustic signatures and infrared thermography.

Table 5-1. Overall Effectiveness of Common ISM Methods

ISM	Percent of Degraded Conditions Detected
Vibration Testing	70
Visual Inspection	55
Acoustic Testing	45
Infrared Thermography	40
Drop out Voltage	30
Contact / Pole Resistance	30
Magnetic Flux	30
Inrush Current	30
Coil Resistance	20
Pick-up Voltage	10
Holding Current	10
Ion Detection	4
Insulation Resistance	0

Inspection, surveillance and monitoring methods were evaluated in the tests on naturally aged relays and circuit breakers, the degraded conditions tests and in the in-situ efforts. The ISM methods were evaluated for each relay and circuit breaker in the Phase II effort. They had been chosen based on their current use in nuclear plant practice, or because they presented the opportunity for improvement in the methods currently in practice. The test results on each type of relay and circuit breaker provided information on the effectiveness of each ISM method. A method was concluded to have been effective at detecting and capable of mitigating aging if it detected significant differences due to aging on the relays and / or circuit breakers on which it was evaluated, during any of the three test series, tests on naturally aged devices, tests on degraded devices and in-situ efforts. Some methods were effective when comparing the results of aged devices. Other methods were effective when detecting differences caused by the degradation conditions applied to each type of relay or circuit breaker.

Each of the ISM methods were rated for effectiveness to detect significant differences caused by age. The ratings were, from highest to lowest, effective, probably effective and ineffective. A method was considered effective when it detected significant differences caused by age in the tests on aged devices, or the tests on devices with degraded conditions. Any method which had detected aging noted during the in-situ efforts was also considered to be effective. A method was considered to probably be effective when differences were noted on aged relays and / or circuit breakers but not enough information was available to judge if the differences were caused by age or may have been caused by other differences in the devices. A method was considered to be ineffective when no changes in the method were noted by age or the degraded conditions.

5.1 Protective Relays

Nineteen ISM methods were evaluated on the protective relays. The results of the Phase II testing have shown eleven methods to have been effective in detecting and therefore capable of mitigating aging, Table 5-2. They were visual inspection, contact resistance, coil resistance, magnetic flux, induction unit pick-up, time / current characteristics, target and seal in, instantaneous trip unit, infrared pyrometry, infrared scanning and on-contact temperature measurement.

Three methods were considered to be probably effective. They were current surge comparison, vibration testing and acoustic testing.

Five methods were ineffective. They were insulation resistance, zero check, inrush current, operating current and ion detection.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice which was summarized in Table 2-1. The ISM methods, in common nuclear plant practice, were visual inspection, time / current characteristic, induction / overcurrent pick-up, target and seal-in and instantaneous trip. All were shown to be effective at detecting and capable of mitigating aging in Phase II. The operating current method, which was the only other common practice, was found to be probably effective. Thus, all of these current methods are considered to be useful and are recommended.

The current practices were sensitive to all of the degraded conditions, for the Westinghouse CO protective relay. However, current practices, for the GE IA, were not as sensitive to most of the degraded conditions. For example, induction unit pick-up was sensitive to four out of five degraded conditions for the Westinghouse CO relay and only one out of five for the GE IA relay.

More effective, than current practice for the GE IA relay, was the improved ISM method of infrared temperature measurement with infrared pyrometer or scanner.

Infrared temperature measurement was more sensitive to the degraded conditions of dirt accumulation, overheat and contact damage than the current method and about the same for the loose connections degraded condition. The increased temperatures would result in significantly reduced expected life to approximately 6% of originally expected.

For the protective relays, the method of infrared temperature measurement is recommended to be added to the current practices of

Table 5-2. ISM Methods Effectiveness
for Protective Relays

ISM	Initial Condition	Degraded Conditions CD	DA	HP	LC	OH
Current Practice						
Visual Inspection	E	E	E	I	E	E
Induction / Overcurrent Pick-up	E	E	E	I	E	E
Target and Seal-In	P	I	E	I	I	E
Time / Current Characteristic	E	I	I	I	I	I
Instantaneous Trip	E	I	I	I	I	I
Operating Current	P	I	I	I	I	I
Advanced Methods						
Infrared Pyrometry	E	E	E	I	E	E
Infrared Scanning	E	P	P	I	P	P
On-contact Temperature	E	P	P	I	P	P
Magnetic Flux	P	E	E	I	E	E
Coil Resistance	E	E	I	I	E	I
Vibration Testing	P	I	E	I	E	E
Acoustic Testing	P	I	E	I	E	E
Contact Resistance	E	I	I	I	E	I
Ion Detection	E	I	I	I	I	I
Inrush Current	I	I	I	I	I	I
Zero Check	I	I	I	I	I	I
Insulation Resistance	I	I	I	I	I	I
Current Surge Comp.	P					

Legend:
CD : Contact Damage
DA : Dirt Accumulation
E : Effective
HP : High Potential
I : Ineffective
LC : Loose Connection
M : Misleading
OH : Overheat
P : Probably Effective

visual inspection, time / current characteristic, induction / overcurrent pick-up, target and seal-in and instantaneous trip.

Infrared temperature measurement should be performed with the cover off of the protective relays and with the relays energized.

5.2 Control Relays

Sixteen ISM methods were evaluated on the control relays. The results of the Phase II testing have shown eleven methods to have been effective in detecting and therefore capable of mitigating aging, Table 5-3. They were visual inspection, contact resistance, coil resistance, magnetic flux, pick-up voltage, drop out voltage, infrared pyrometry, infrared scanning, on-contact temperature measurement, vibration testing and acoustic testing.

Three methods were considered to be probably effective. They were inrush current, holding current and current surge comparison.

Two methods were ineffective. They were insulation resistance and ion detection.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice which was summarized in Table 2-1. The ISM methods, in common nuclear plant practice, were visual inspection, pick-up voltage and drop out voltage. All three were shown to be effective at detecting and capable of mitigating aging in Phase II. Thus, all of these current methods are considered to be useful and are recommended.

However, the current practices were not sensitive to most of the degraded conditions. Pick-up voltage was sensitive to four out of ten degraded conditions. Drop out voltage was sensitive to two out of ten degraded conditions.

The improved ISM methods of magnetic flux, temperature measurement with infrared pyrometer or scanner, vibration testing and acoustic testing were sensitive to additional degraded conditions of control relays. Each were sensitive to some degraded conditions for which current practice was insensitive.

Infrared temperature measurement was considerably more sensitive to the degraded conditions of dirt accumulation, overheat, shorted coil turns and loose connections than the current practice of pick-up voltage and drop out voltage.

The sensitivity of infrared temperature measurement and its ability to detect aging was exemplified during the dirt accumulation degraded condition in which the temperature of the SD219 control relay increased from 140°F to 175°F. For this same degraded condition, the pick-up voltage decreased by 25%, which would be considered better. The drop out voltage did not change due to the dirt accumulation degraded condition. These increased

Table 5-3. ISM Methods Effectiveness for Control Relays

ISM	Initial Condition	Degraded Conditions BA	CCR	CD	DA	HP	ICR	LC	LCC	OH	SCT
Current Practice											
Visual Inspection	I	E	I	E	E	I	I	E	I	E	I
Pick-up Voltage	E	E	I	I	M	I	I	I	I	M	M
Drop out Voltage	I	I	I	E	I	I	I	I	I	I	E
Advanced Methods											
Vibration Testing	P	E	I	E	P	I	I	E	E	E	P
Acoustic Testing	P	E	I	E	P	I	I	E	I	E	P
Infrared Pyrometry	E	I	I	I	E	I	I	E	I	E	E
Infrared Scanning	E				P			P		P	P
On-contact Temp.	E				P			P		P	P
Contact Resistance	E	E	I	E	I	I	I	I	I	E	E
Magnetic Flux	I	E	I	E	E	I	I	I	I	E	E
Coil Resistance	I	I	I	I	I	I	I	I	I	I	E
Inrush Current	I	I	I	I	I	I	I	I	I	I	E
Holding Current	I	I	I	I	I	I	I	I	I	I	E
Current Surge Comp.	P										
Ion Detection	I	I	I	I	I	I	I	I	I	I	I
Insulation Resistance	I	I	I	I	I	I	I	I	I	I	I

Legend:

BA : Blocked Armature
CCR : Contact to Contact Resistance
CD : Contact Damage
DA : Dirt Accumulation
E : Effective
HP : High Potential
I : Ineffective
ICR : Increased Coil Resistance
LC : Loose Connection
LCC : Low Contact Current
M : Misleading
OH : Overheat
P : Probably Effective
SCT : Shorted Coil Turns

temperatures would result in significant reduction of expected life, in this case, a reduction to approximately 25% of original expected life.

To be effective, the magnetic flux had to be measured at percentages of the voltage rating in order to ascertain the effect of the magnetic field changes and the aging that may be causing it to change. Thus the addition of magnetic flux measurement would be expected to impact the current maintenance practice since this would require more intrusion into the control relays to accomplish. Since magnetic flux was shown to be sensitive to the degraded conditions of dirt accumulation, overheat, shorted coil turns, and blocked armature, which also caused significant changes in the other methods of pick-up voltage, drop out voltage or temperature measurement, it is not recommended.

Vibration testing, vibration signature analysis of the transient during control relay change of state, was more sensitive to the degraded conditions of loose connections, contact damage, blocked armature, and overheat than the current practice. The vibration testing method was non-intrusive, but does require a relay change of state. During the in-situ efforts, the practicability of vibration testing was assessed and found to be practicable.

Acoustic testing, acoustic signature analysis of the control relay change of state, was sensitive to the same degraded conditions as vibration testing. However, the practicability of obtaining the necessary data in an operating plant was limited to areas in the plant that have a high signal to noise ratio. Since the acoustic signal of control relays was small, the noise level in most plant areas observed during the in-situ effort, limit the practicability of acoustic monitoring of control relays to areas of low noise.

The control relays evaluated in Phase II are vulnerable to significant undetectable age related thermal degradation, using the current nuclear practice of visual inspection, pick-up voltage and drop out voltage.

For the control relays, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices of visual inspection, pick-up voltage, and drop out voltage tests.

5.3 Electronic Relays

Twelve ISM methods were evaluated on the electronic relays. The results of the Phase II testing have shown four methods to have been effective in detecting and therefore capable of mitigating aging, Table 5-4. They were visual inspection, overcurrent sensing pick-up, instantaneous overcurrent and vibration testing.

Eight methods were ineffective. They were contact resistance, coil resistance, time / current characteristic, infrared pyrometry, infrared scanning, on-contact temperature, acoustic testing and ion detection.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice which was summarized in Table 2-1. In common nuclear plant practice, the three methods of visual inspection, induction / overcurrent pick-up and instantaneous trip were effective at detecting and capable of mitigating aging. Thus, all of these current methods are considered to be useful and are recommended.

Additionally, the improved ISM method of vibration testing was sensitive to all of the degraded conditions on the electronic relay. However, the vibration signal level was low and the practicability of obtaining the necessary data in an operating plant would be limited to areas in the plant that have a high signal to noise ratio. Since the vibration signal of electronic relays was small, the noise level in most plant areas observed during the in-situ effort, limit the practicability of vibration monitoring of electronic relays to areas of low noise.

Table 5-4. ISM Methods Effectiveness
for Electronic Relays

ISM	Initial Condition	CD	DA	HP	LC	OH
		Degraded Conditions				
Current Practice						
Instantaneous Trip	P	E	E	E	E	E
Visual Inspection	P	E	E	I	E	E
Induction / Overcurrent Pick-up	P	I	I	I	E	E
Time / Current Characteristic	P	I	I	I	I	I
Advanced Methods						
Vibration Testing	P	P	P	P	P	P
Contact Resistance	P	I	I	I	I	I
Coil Resistance	P	I	I	I	I	I
Acoustic Testing	P	I	I	I	I	I
Ion Detection	P	I	I	I	I	I
Infrared Pyrometry	P	I	I	I	I	I
Infrared Scanning	P					
On-contact Temperature	P					

Legend:
CD : Contact Damage
DA : Dirt Accumulation
E : Effective
HP : High Potential
I : Ineffective
LC : Loose Connection
M : Misleading
OH : Overheat
P : Probably Effective

5.4 Auxiliary Relays

Sixteen ISM methods were evaluated on the auxiliary relays. The results of the Phase II testing have shown fourteen methods to have been effective in detecting and therefore capable of mitigating aging, Table 5-5. They were visual inspection, contact resistance, coil resistance, magnetic flux, pick-up voltage, drop out voltage, inrush current, holding current, infrared pyrometry, infrared scanning, on-contact temperature measurement, vibration testing, acoustic testing, and ion detection.

One method was considered to be probably effective. It was current surge comparison.

One method was ineffective. It was insulation resistance.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice. The ISM methods, in common nuclear plant practice, were visual inspection, pick-up voltage and drop out voltage. All three were shown to be effective at detecting and capable of mitigating some aging in Phase II. Thus, all of these current methods are considered to be useful.

However, the current practices were not sensitive to many of the degraded conditions. Pick-up voltage was sensitive to one of the degraded conditions for HFA relays and one of the degraded conditions for MG-6 relays. Drop out voltage was sensitive to one of the degraded conditions on the HFA and five for the MG-6 relays. Pick-up voltage was found to be misleading on the degraded condition of shorted coil turns and contact damage(for the HFA relay).

More effective than current practice on degraded conditions of auxiliary relays were the improved ISM methods of temperature measurement with infrared pyrometer or scanner, vibration testing and acoustic testing. Each were more sensitive to more of the degraded conditions than current practice.

Infrared temperature measurement was considerably more sensitive to the degraded conditions of dirt accumulation, overheat, blocked armature and loose connections than the current practice of pick-up voltage and drop out voltage.

The sensitivity of infrared temperature measurement and its ability to detect aging was exemplified during the loose connections test in which the temperature inside the GE HFA auxiliary relay increased from 110^{O}F to over 600^{O}F. For this same degraded condition, the pick-up voltage increased by 12 % and was

Table 5-5. ISM Methods Effectiveness for Auxiliary Relays

ISM	Initial Condition	BA	CCS	CD	DA	HP	ICR	LC	LCC	OH	SCT
		Degraded Conditions									
Current Practice											
Visual Inspection	E	E	I	E	E	I	I	E	I	E	I
Pick-up Voltage	E	I	I	E/M	I	I	I	I/E	I	I	M
Drop out Voltage	I	E/E	I	E/I	E/I	I	I	E/I	I	I	E/I
Advanced Methods											
Vibration Testing	P	E	I	I	E	I	E/I	E	I	E	E/I
Acoustic Testing	P	E	I	I	E	I	E/I	E	I	E	E/I
Infrared Pyrometry	E	I/E	I	I	E	I	I	E	I	E	E/I
Infrared Scanning	E	P			P			P		P	P
On-contact Temp.	E	P			P			P		P	P
Contact Resistance	I	E	I	E/I	E/I	I	I	E	I	E/I	E/I
Magnetic Flux	I	E	I	I	I	I	I	I	I	I	E
Coil Resistance	I	I	I	I	I	I	I	I/E	I	I	E/I
Inrush Current	I	I	I	E	E	I	I	I	I	I	E
Holding Current	I	E/I	I	I	I	I	I	I	I	I	E/I
Current Surge Comp.	P										
Ion Detection	P	P	P	P	P	P	P	E	P	P	E
Insulation Res.	I	I	I	I	I	I	I	I	I	I	I

Legend:

BA : Blocked Armature
CCS : Contact to Contact Short
CD : Contact Damage
DA : Dirt Accumulation
E : Effective
HP : High Potential
I : Ineffective
ICR : Increased Coil Resistance
LC : Loose Connection
LCC : Low Contact Current
M : Misleading
OH : Overheat
P : Probably Effective
SCT : Shorted Coil Turns

Note : When two entries are listed, the first is for the Westinghouse relay and the second is for the GE relay.

still in specification. The drop out voltage did not change due to the loose connection. The significantly increased temperatures would result in extremely reduced expected lives and a few would be fire hazards.

Vibration testing, vibration signature analysis of the transient during auxiliary relay change of state, was more sensitive to the degraded conditions of loose connections, contact damage, blocked armature, overheat, increased coil resistance, shorted coil turns and dirt accumulation than the current practice. The vibration testing method was non-intrusive, but does require a relay change of state. During the in-situ efforts, the practicability of vibration testing was assessed and found to be practicable.

Acoustic testing, acoustic signature analysis of the auxiliary relay change of state, was more sensitive to the same degraded conditions as vibration testing. However, the practicability of obtaining the necessary data in an operating plant was limited to areas in the plant that have a high signal to noise ratio. Since the acoustic signal of auxiliary relays was small, the noise level in most plant areas observed during the in-situ effort, limit the practicability of acoustic monitoring of auxiliary relays to areas of low noise.

The auxiliary relays evaluated in Phase II are vulnerable to significant undetectable age related thermal degradation, using the current nuclear practice of visual inspection, pick-up voltage and drop out voltage.

For the auxiliary relays, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices of visual inspection, pick-up voltage, and drop out voltage tests.

The time for performance of pick-up and drop out tests was observed to be approximately one half man-hour per relay, with a two man crew, during the in-situ tests. The infrared temperature measurement using a scanner was accomplished in approximately 0.1 man-hour per relay, using a one man crew. Obtaining the vibration signature with a hand held data acquisition computer was accomplished at the same time that a relay changes state.

5.5 Timing Relays

Seventeen ISM methods were evaluated on the timing relays. The results of the Phase II testing have shown thirteen methods to have been effective in detecting and therefore capable of mitigating aging, Table 5-6. They were visual inspection, contact resistance, coil resistance, magnetic flux, pick-up voltage, drop out voltage, inrush current, holding current, timing, infrared

Table 5-6. ISM Methods Effectiveness for Timing Relays

ISM	Initial Condition	Degraded Conditions BA	CD	DA	HP	ICR	LC	LCC	OH	SCT
Current Practice										
Visual Inspection	I	I	I	E	I	I	E	I	E	I
Timing	I	E	E	I	I	I	E	I	I	I
Pick-up Voltage	E	I	I	I	I	I	I	I	I	M
Advanced Methods										
Vibration Testing	P	E	E	E	I	E	E	I	E	I
Inrush Current	I	I	E	E	I	I	E	I	E	E
Infrared Pyrometry	I	I	I	E	I	E	E	I	E	E
Infrared Scanning	I	I	I	E	I	E	P	I	E	E
On-contact Temp.	I	I	I	P	I	P	P	I	P	P
Drop out Voltage	E	I	I	E	I	1	I	I	I	E
Acoustic Testing	P	E	I	I	I	I	I	I	E	I
Magnetic Flux	I	I	I	I	I	I	I	I	E	E
Contact Resistance	I	I	E	I	I	I	I	I	I	I
Coil Resistance	I	I	I	I	I	I	I	I	I	E
Holding Current	I	I	I	I	I	I	I	I	I	E
Ion Detection	I	I	I	I	I	I	I	I	I	I
Insulation Res.	I	I	I	I	I	I	I	I	I	I
Current Surge Comp.	P									

Legend:

BA : Blocked Armature
CD : Contact Damage
DA : Dirt Accumulation
E : Effective
HP : High Potential
I : Ineffective
ICR : Increased Coil Resistance
LC : Loose Connection
LCC : Low Contact Current
M : Misleading
OH : Overheat
P : Probably Effective
SCT : Shorted Coil Turns

pyrometry, infrared scanning, vibration testing and acoustic testing.

One method was considered to be probably effective. It was current surge comparison.

Three methods were ineffective. They were insulation resistance, on-contact temperature and ion detection.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice. The ISM methods, in common nuclear plant practice, were visual inspection, pick-up voltage and timing tests. All three were shown to be effective at detecting and capable of mitigating some aging in Phase II. Thus, all of these current methods are considered to be useful.

However, the current practices were not sensitive to many of the degraded conditions. In particular, pick-up voltage changed due to only one of the nine degraded conditions. A pick up voltage decrease of 10% was caused by the shorted coil turns degraded condition. A decrease would normally be considered beneficial and therefore the possibility exits that this degraded condition would be misleading. A significant shorted coil turns degradation existed in the relay at that time. Additionally, other significant degradations were undetected by this method. Timing was sensitive to three degraded conditions, contact damage, loose connections and blocked armature.

More effective than current practice on degraded conditions of timing relays were the improved ISM methods of infrared temperature measurement with infrared pyrometer or scanner, inrush current, and vibration testing. Each were more sensitive to more of the degraded conditions.

Infrared temperature measurement was considerably more sensitive to the degraded conditions of dirt accumulation, overheat, loose connections, shorted coil turns and increased coil resistance than the current practice of pick-up voltage and timing.

The sensitivity of infrared temperature measurement and its ability to detect aging was exemplified during the shorted coil turns degraded condition in which the temperature increased from $110^{\circ}F$ to over $170^{\circ}F$ on the timing relay. For this same degraded condition, the pick-up voltage decreased by 10%, which would be judged to be improving. Also, the timing characteristic did not change during the shorted coil turns degradation condition and because the coil is hidden from view, visual inspection was also ineffective. This increase in temperature would result in a reduced expected life to approximately 6% of the original expected life.

Inrush current was more sensitive to the degraded conditions of dirt accumulation, overheat, contact damage and shorted coil turns than the current nuclear practice. The inrush current method, applicable to ACC relays, was non-intrusive and was obtained with current probes which were clamped onto the field wire coil connection. A change of state of the relay was required to acquire the current signature.

Examples of the effectiveness of the inrush current method over the current practice were noted during the overheat and shorted coil turns degraded conditions. The overheat degraded condition caused the inrush current to increase by almost 250% and the shorted coil turns caused an increase of 500% in inrush current. Pick-up voltage decreased for both of these degraded conditions less than 5% for overheat and approximately 10% for the shorted coil turns. Timing was unaffected by both of these degraded conditions.

Vibration testing, vibration signature analysis of the transient during timing relay change of state, was more sensitive to the degraded conditions of loose connections, contact damage, blocked armature, overheat, increased coil resistance and dirt accumulation than the current practice. The vibration testing method was non-intrusive, but does require a relay change of state.

Thus, timing relays may be vulnerable to significant undetectable age related thermal degradation, using the current nuclear practice of visual inspection, pick-up voltage and timing measurements.

For the timing relays, the methods of infrared temperature measurement, inrush current and vibration testing are recommended to be added to the current practices of visual inspection and timing tests and deleting the pick-up voltage tests.

A proposed technique would be to measure infrared temperature on all energized relays, then the relay cycled in-situ while timing, inrush current and vibration signatures are obtained. This new procedure is estimated to take approximately 15 minutes per relay. The current practice is intrusive and requires disconnection of the relay and voltage varied to obtain the pick-up voltage or removal of the relay and insertion in a test set. The nuclear plant procedures estimate that current practice is one man hour per relay.

5.6 Molded Case Circuit Breakers

Sixteen ISM methods were evaluated on the molded case circuit breakers. The results of the Phase II testing have shown twelve methods to have been effective in detecting and therefore capable of mitigating aging, Table 5-7. They were visual inspection, pole resistance, mechanical actuation, 100% rated current hold-in, 135% rated current, 300% overcurrent, instantaneous trip, infrared pyrometry, infrared scanning, on-contact temperature measurement, vibration testing, and acoustic testing.

Four methods were ineffective. They were insulation resistance, ion detection, 600% overload and dielectric.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice. The ISM methods, in common nuclear plant practice, were visual inspection, instantaneous trip, pole resistance, insulation resistance, 100% rated current hold-in, 135% rated current hold-in, and 300% overcurrent. All were shown to be effective, when properly performed, at detecting and capable of mitigating aging in Phase II, except for insulation resistance and mechanical actuation, which were ineffective. Insulation resistance is useful to assure connections are of high integrity for personnel and equipment safety, after maintenance is performed. The instantaneous trip test was shown to be effective when tests were performed below and above the instantaneous trip range. Thus, all of these current methods are considered to be useful.

Additionally effective for molded case circuit breakers were the improved ISM methods of infrared temperature measurement with infrared pyrometer or scanner, and vibration testing.

Infrared temperature measurement was sensitive to the degraded condition of loose connections. The advantage of infrared temperature measurement was the detection of significant temperatures before they damaged molded case circuit breaker internals. As was noted in the tests on aged devices, the failure modes caused by overheating of the molded case circuit breakers were non-conservative.

Vibration testing was the only method which exhibited differences with all of the degraded conditions. The vibration signatures are obtainable with a hand held data acquisition computer. Vibration signatures should be obtained during manual actuation, the 300% overcurrent and instantaneous trip tests since these tests check the performance of the three different trip initiating functions. All three of these functions were shown to be mutually exclusive in the tests on aged molded case circuit breakers.

Table 5-7. ISM Methods Effectiveness for Molded Case Circuit Breakers

ISM	Initial Condition	Degraded Conditions DA	HP	LC
Current Practice				
Instantaneous Trip	E	E	E	E
135% Rated Current Hold-in	E	E	E	E
Visual Inspection	E	E	I	E
Pole Resistance	I	E	E	E
100% Rated Current Hold-in	I	I	I	E
300 % Overcurrent	E	I	I	I
Insulation Resistance	I	I	I	I
Mechanical Actuation	I	I	I	I
Advanced Methods				
Vibration Testing	P	E	E	E
Acoustic Testing	P	E	E	E
Infrared Pyrometry	E	I	I	E
Infrared Scanning	E	I	I	E
On-contact Temperature	E	I	I	P
Ion Detection	I	I	I	I
600 % Overload	I	I	I	I
Dielectric	I	I	I	I

Legend:
DA : Dirt Accumulation
E : Effective
HP : High Potential
I : Ineffective
LC : Loose Connection
M : Misleading
P : Probably Effective

For the molded case circuit breaker, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices. Additionally, it is recommended to modify the current practice of instantaneous trip testing to assure that instantaneous trip occurs within the instantaneous range by tests below and above the instantaneous trip range.

5.7 Metal Clad Circuit Breakers

Thirteen ISM methods were evaluated on the metal clad circuit breakers. The results of the Phase II testing have shown seven methods to have been effective in detecting and therefore capable of mitigating aging. They were visual inspection, mechanical actuation, long time delay overcurrent, short time delay overcurrent, infrared pyrometry, vibration testing and acoustic testing.

Three methods were considered to be probably effective. They were instantaneous trip, infrared scanning and on-contact temperature measurement.

Three methods were ineffective. They were insulation resistance, pole resistance and ion detection.

The result of the effectiveness in the Phase II testing was compared to the current nuclear practice. The ISM methods, in common nuclear plant practice, were visual inspection, mechanical actuation, instantaneous trip, pole resistance, insulation resistance, long time delay overcurrent, short time delay overcurrent and lubrication inspection, which is part of visual inspection. All were shown to be effective at detecting and capable of mitigating aging in Phase II, except for insulation resistance, which was ineffective. Insulation resistance is useful to assure connections are of high integrity for personnel and equipment safety, after maintenance is performed. Thus, all of these current methods are considered to be useful.

Additionally recommended for metal clad circuit breakers are the improved ISM methods of infrared temperature measurement with infrared pyrometer or scanner, and vibration testing. The metal clad circuit breakers are vulnerable to significant overheating caused by loose connections similar to that experienced on the molded case circuit breaker evaluated in Phase II. Overheating can result in non-conservative failures of metal clad circuit breaker components as was evidenced on the long time delay function of the EX trip device.

Additionally recommended is vibration monitoring during trip tests. The history of the main trip function and the initiating events such as long time delay, instantaneous trip or short time delay were evident with the vibration signatures. Vibration testing exhibited differences with all of the degraded conditions. The vibration signatures were obtainable with a hand held data acquisition computer, at the same time that the other trip tests were being performed.

Vibration signatures should be obtained during manual actuation, long time delay overcurrent, short time delay overcurrent and instantaneous trip tests on each pole. Since these tests check the performance of the four different trip initiating functions. All of these functions were shown to be mutually exclusive in the tests on aged metal clad circuit breakers.

For the metal clad circuit breaker, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices.

Table 5-8. ISM Methods Effectiveness
for Metal Clad Circuit Breakers

ISM	Initial Condition	Degraded Conditions				
		LC	LL	OH	OL	RL
Current Practice						
Visual Inspection	E	E	E	E	E	E
Long Time Delay Overcurrent	E	E	E	E	I	E
Mechanical Actuation	E	I	I	I	I	I
Short Time Delay Overcurrent	E	I	I	I	I	I
Instantaneous Trip	P					
Pole Resistance	I	I	I	I	I	I
Insulation Resistance	I	I	I	I	I	I
Advanced Methods						
Vibration Testing	E	E	E	E	P	P
Acoustic Testing	P	P	E	E	P	P
Infrared Pyrometry	I	I	I	E	I	I
Infrared Scanning	I	I	I	P	I	I
On-contact Temperature	I	I	I	P	I	I
Ion Detection	I	I	I	I	I	I

Legend:

E : Effective
I : Ineffective
LC : Loose Connection
LL : Loss of Lubrication
M : Misleading
OH : Overheat
OL : Overload
P : Probably Effective
RL : Re-Lubrication

6. SERVICE LIFE PREDICTION

Service life is a complicated function of many variables. Some factors which determine the life of relays and circuit breakers are inherently random, such as manufacturing defects and quality control problems. Other factors which determine life may be time dependent. The time dependent factors may have constant, increasing or decreasing rates with respect to time. Still other factors which determine life may be dependent on the number of operations, cycles or changes of state.

Quality control problems tend to cause a lot of specific life limiting failures, which once identified can be segregated and eliminated from the population of circuit breakers and relays available for or in operation. The identification of life limiting factors other than quality control problems and their segregation from the population is inherently more difficult. These other life limiting factors are somewhat less random although uncertainty is a part of each of them.

The literature on circuit breakers and relays from manufacturers, service organizations, research laboratories and other sources contains significant discussion as to maintenance to be performed to make relays and circuit breakers last longer. However, the literature is noticeably lacking in quantification of the expected calendar length of service life.

Life limits found in the Phase II research

Relays and circuit breakers were evaluated in the Phase II research which were up to 30 years old. Significant aging had taken place on many of the devices. However, the significant aging was not strongly correlated to length in service. In general devices which were 20 to 30 years old had some performance parameters which had degraded significantly, and others which had not degraded. They also had generally not degraded to the point that additional satisfactory performance would not be expected. Calendar age was not the most significant indicator of loss of ability of the relays or circuit breakers to perform their functions. A long calendar age, however, would be expected to increase the probability that other significant aging conditions, such as overheating due to failure of other components and quantity of cycles or trips experienced.

More important than calendar age was the impact of other aging factors, the most important and consistent being exposure to high temperatures either from within the devices or caused external to the devices by environment or other degradations such as loosening of connections, vibration, thermal cycles, etc..

The research failed to discover evidence of service life limit related to calendar life of a properly maintained relay or circuit breaker.

The research discovered age related degraded conditions which limited the life and in some cases caused failure of some of the relays and circuit breakers. These degraded conditions caused failures of molded case and metal clad circuit breakers which were non-conservative.

For instance, 30 year old molded case and metal clad circuit breakers were found to be performing well within specifications, while an eight year old molded case circuit breaker had degraded to the point that it failed to trip at currents up to 10,000 amps. The root cause of this condition was significant thermal aging caused by a loose connection on an adjoining bus bar.

The lack of maintenance was also shown to limit the life of a metal clad circuit breaker. The root cause of failure of a trip device on a 29 year old metal clad circuit breaker was that the dashpot had leaked out all of its oil. Any of the common nuclear maintenance methods would have detected this gross degradation, presumably substantially before the 29th year.

Improper maintenance was the cause of failure on a molded case circuit breaker evaluated in Phase II. The circuit breaker failed to interrupt a current of 200 amps, 125% of rating. The current caused the temperature to exceed 580°F and the trip mechanism melted and permanently precluded the breaker from tripping. The root cause of this failure was a misaligned trip pin, which probably happened during prior maintenance.

Maintenance Intervals

The maintenance intervals recommended by manufacturers and current nuclear practice were reviewed in the Phase II research.

It was common for manufacturers to specify maintenance intervals in terms of operations. For instance, metal clad circuit breaker periodic inspection intervals were stated to be a function of application and operating conditions. Periodic maintenance was recommended after 2000 operations, which would be lessened depending on importance to overall plant operation, atmospheric conditions, dust and frequency of fault interruptions.

Common nuclear plant inspection intervals were 1 plant cycle for safety related 4KV metal clad circuit breakers and 480 Volt metal clad circuit breakers protecting EQ-related equipment, 2 plant cycles for 4KV metal clad circuit breakers which operated only during outages and 480 volt metal clad breakers protecting non-EQ equipment and 3 cycles for non-safety related metal clad circuit breakers.

Common nuclear plant inspection intervals were 2.5 years for safety-related and 4.5 years for non-safety related auxiliary and protective relays.

Common nuclear plant inspection intervals were 1 year for safety-related timing relays.

Common nuclear plant inspection intervals were 1 year for control relays.

Additionally, relays in the diesel generator sequencing logic had inspection intervals of 1 month.

The Phase II research showed that GE IAC relays were still in calibration after a 4 year interval. Additionally, no degradation was found which would have required the 1 month inspection intervals on relays in the diesel generator sequencing logic.

For the other intervals, no other specific information was discovered which would indicate that modification of the inspection intervals was required.

However, some of the IS & MM methods in current practice were not as effective as some of the improved methods to detect age related degradation. The use of more effective methods, which were less intrusive and required less man-hours to perform, would form the basis for conditioned based maintenance which could justify extension of inspection intervals for more intrusive and time consuming IS & MM methods.

A model of the factors which determine service life could form the basis of a conditioned based maintenance program. The model could predict the rate of change in parameters with respect to time. Maintenance would be scheduled when necessary based on the condition of the device rather than at some arbitrary time.

Clearly one of the significant factors in predicting survivability for relays and circuit breakers is temperature. High temperatures were the root cause of the failure of thermal element trip devices and magnetic trip devices in molded case circuit breakers tested in Phase II. Several of the degraded conditions caused excessive temperatures. Temperatures over 600°F were caused by loose connections in auxiliary relays. Dirt accumulation caused temperatures in excess of 470°F on auxiliary relays. Loose connections caused temperatures over 440°F on molded case circuit breakers. It is generally accepted that circuit breakers are more prone to failure if temperatures are excessive. Additionally, it is known that these devices follow an Arrhenius aging relationship in which the expected service life is a direct function of temperature. It was seen in some of the degraded conditions that service life would be reduced to 6% to 25% of expected life due to the temperature increases observed on the devices. These detrimental temperatures were present on several devices. The timing relays were a good example. The higher than normal temperatures were causing a significant reduction in service life. However, this would commonly go unnoticed because the parameter normally tested was pick-up voltage, which was not degrading. Thus, the use of pick-up voltage as the only maintenance method would overlook the increased temperatures and thus failures would not have been predicted. The function of other factors to affect service life are more subtle and less obvious. A basic assumption in the model is that the relay and circuit breaker is inherently a good design which is free from quality control or lot defects.

The major factors which have been shown by this research to impact the service life of relays and circuit breakers in nuclear plant service are :

- o Time in service (TS)
- o Temperature of the device (T)
- o Vibration at the device (V)
- o Cleanliness of the surrounding environment (C)
- o Propensity for looseness of critical parts (L)
- o Propensity to experience overheated conditions (O)
- o Propensity for damage during maintenance (M)
- o Duty cycle (D)
- o Cool down period prior to re-energization (CD)
- o Ionizing radiation (R)

Infrared thermography was effective at detecting significant temperature changes caused by the majority of degraded conditions for all relay and circuit breaker types. Additionally, vibration testing of some types of relays and all types of circuit breakers was effective at detecting the majority of degraded conditions.

Thus the combination of Infrared inspection and vibration monitoring, with other effective methods, depending on device type, could form the basis of condition based maintenance intervals. The changes in parameters seen through the use of these non-intrusive methods could be utilized to aid in scheduling the more intrusive methods. The net impact would be more effective aging mitigation. Intrusive tests have the potential to cause failure of equipment through improper maintenance.

The factors effecting service life would then be simplified to be a function of the non-intrusive techniques when a conditioned based maintenance program is fully matured.

The Phase II research provides some starting points for this approach. The degraded conditions tests were purposely severe and for the most part constituted a worst case degraded condition short of device failure. For instance, when evaluating infrared temperatures, if temperatures are near the baseline conditions the degradation rate is constant. When temperatures increase, the level and rate of increase would be used to decide when maintenance should be performed. Any temperatures approaching the levels seen during the degradation tests would be immediate cause for concern and maintenance would be scheduled shortly.

This method could also be used for vibration monitoring on most of the relay and circuit breaker types. Also, inrush current monitoring on timing relays could be used in a condition based maintenance program because it was very sensitive to the degraded conditions common to timing relays.

7. SIGNIFICANCE, CONCLUSIONS AND RECOMMENDATIONS

The potential significance and uses of the research results are discussed herein. The research conclusions and recommendations are also discussed in this section.

7.1 Significance

Relays and circuit breakers are important nuclear power plant equipment which are susceptible to degradation with time. Over the last decade, failures of relays and circuit breakers have resulted in significant events at nuclear power plants which have had important safety impacts. Failures of these devices have resulted in many NRC notices and bulletins. As nuclear plants age, those devices which are susceptible to increased failures with age could provide more challenges to the safe operation of nuclear plants.

It is the challenge of a good preventive maintenance program to be sensitive to the effects of aging. Early identification of age related degradation increases the probability that the safety significance of this aging is minimized. An effective inspection, surveillance and monitoring program enhances mitigation of the impact of age related degradation on the safety of nuclear plant operations.

Therefore, the significance of the NPAR Phase II comprehensive aging assessment of relays and circuit breakers is summarized in five elements:

- o Effective inspection, surveillance and monitoring methods for relays and circuit breakers which are sensitive to aging degradation were identified,
- o Inspection, surveillance and monitoring methods for relays and circuit breakers which are more sensitive to aging degradation than current nuclear plant practice were identified,
- o Improved inspection, surveillance and monitoring methods for relays and circuit breakers which are less intrusive and have the potential for condition based maintenance were identified,
- o The identification of effective inspection, surveillance and monitoring methods for relays and circuit breakers which are sensitive to aging degradation provides the licensees necessary information for managing the aging process for these devices.

- o The identification of effective inspection, surveillance and monitoring methods for relays and circuit breakers which are sensitive to aging degradation provides the regulators with information useful for assessing the adequacy of licensees efforts to manage aging and licensees responses to regulatory concerns on relays and circuit breakers.

For each of the relay and circuit breaker types evaluated in the Phase II research, IS & MM methods were identified which were sensitive to the effects of aging and effective in detecting aging. Some improved IS & MM methods are more sensitive to degradation and therefore more effective than current nuclear practice. The potential for conditioned based maintenance exists for relays and circuit breakers. Conditioned based maintenance would be expected to be more cost effective than time based maintenance.

This research has particular significance with respect to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," Information Notice 84-20, "Service Life of Relays in Safety-related Systems", IE Bulletin 84-02, "Failures of General Electric Type HFA Relays in Use in Class 1E Safety Systems. and NRCB 88-10, "Nonconforming Molded Case Circuit Breakers."

Generic letter 83-28, IN 84-20 and IE Bulletin 84-02 require licensees to have preventive maintenance and surveillance programs for circuit breakers and relays. This research provides information on the effectiveness of preventive maintenance methods that are required by these documents. The research showed that improved IS & MM methods were more effective than current nuclear practice at detecting aging and mitigating the effects of aging for specific devices identified in these documents.

For instance IE Bulletin 84-02 notified the industry about shorter than expected service life of Agastat Timing relays, GE HFA auxiliary relays and GTE Sylvania control relays. Current nuclear practice of pick-up voltage testing was shown to be sensitive to only one out of eight degraded conditions for the GE HFA relay, and one out of nine degraded conditions for the Agastat timing relays.

The auxiliary relays evaluated in Phase II were vulnerable to significant undetectable age related thermal degradation, using the current nuclear practice of visual inspection, pick-up voltage and drop out voltage.

Timing relays may be vulnerable to significant undetectable age related thermal degradation using the current nuclear practice of visual inspection, pick-up voltage and timing measurements.

Improved IS & MM methods were identified in this research to be more effective than current nuclear practice, for auxiliary relays and timing relays.

NRCB 88-10 required that certain molded case circuit breakers be tested for a variety of IS & MM methods. One of the methods was a 600% overload test. This research has shown this method to be ineffective at detecting aging. The method for instantaneous trip function testing specified in NRCB 88-10 was found to effective at detecting aging but current industry practice may not assure that instantaneous trip occurs within the instantaneous range unless tests are performed below and above the instantaneous trip range, as noted in NRCB 88-10.

7.2 Conclusions

The results of the Phase II efforts on relays and circuit breakers have shown that current nuclear inspection, surveillance and monitoring methods are effective at detecting and mitigating some of the degraded conditions caused by aging.

Improved IS & MM methods have been identified which provide a higher level of assurance that aging will be detected and mitigated. The improved methods have been demonstrated to be practicable in commercial nuclear power plants. The potential exists that the implementation of the improved methods in nuclear plants would minimize the impact of aging and result in more cost effective maintenance on relays and circuit breakers

7.3 Recommendations

It is recommended that current nuclear industry practice of inspection, surveillance and maintenance on relays and circuit breakers be modified in order to increase the assurance that aging degradation is detected and mitigated as follows:

For protective relays, the method of infrared temperature measurement is recommended to be added to the current practices of visual inspection, time / current characteristic, induction / overcurrent pick-up, target and seal-in and instantaneous trip.

Infrared temperature measurement should be performed with the cover off of the protective relays and with the relays energized.

For control relays, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices of visual inspection, pick-up voltage, and drop out voltage tests.

For electronic relays, common nuclear plant practice of visual inspection, induction / overcurrent pick-up and instantaneous trip were considered to be useful and are recommended.

For auxiliary relays, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices of visual inspection, pick-up voltage, and drop out voltage tests.

For timing relays, the methods of infrared temperature measurement, inrush current and vibration testing are recommended to be added to the current practices of visual inspection and timing tests and pick-up voltage tests deleted.

For molded case circuit breakers, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices. Additionally, it is recommended to modify the current practice of instantaneous trip testing to assure that instantaneous trip occurs within the instantaneous range by tests below and above the instantaneous trip range.

For metal clad circuit breakers, the methods of infrared temperature measurement and vibration testing are recommended to be added to the current practices.

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APPENDIX A

NRC Information Notices, Bulletins, and Generic Letters on Relays and Circuit Breakers Related Problems in Nuclear Power Plants

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2. IE Bulletin No. 79-09, "Failures of GE Type AK-2 Circuit Breakers in Safety-Related Systems," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, April 17, 1979.

3. IE Bulletin No. 79-11, "Faulty Overcurrent Trip Device in Circuit Breakers for Engineered Safety Systems," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, May 22, 1979.

4. IE Information Notice No. 81-01, "Possible Failures of General Electric Type HFA Relays," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, January 16, 1981.

5. U.S Nuclear Regulatory Commission, Circular 81-12, "Inadequate Periodic Test Procedure of PWR Protection System," July 22, 1981.

6. IE Information Notice No. 82-04, "Potential Deficiency of Certain Agastat E-7000 Series Time-Delay Relays," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, March 10, 1982.

7. IE Information Notice No. 82-13, "Failures of General Electric Type HFA Relays," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, May 10, 1982.

8. IE Bulletin No. 83-01, "Failure of Reactor Trip Breakers to Open on Automatic Trip Signals," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, February 25, 1983.

9. IE Bulletin No. 83-04, "Failure of the Undervoltage Trip Function of Reactor Trip Breakers," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, March 11, 1983.

10. IE Bulletin No. 83-08, "Electrical Circuit Breakers with an Undervoltage Trip Feature in Use in Safety-Related Applications Other Than the Reactor Trip System," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, December 28, 1985.

11. IE Information Notice No. 83-18, "Failures of the Undervoltage Trip Function of Reactor Trip System Breaker," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, April 1, 1983.

12. IE Information Notice No. 83-19, "General Electric Type HFA Relay Contact Gap and Wipe Setting Adjustments," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, April 6, 1983.

13. NRC Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, July 8, 1983.

14. IE Information Notice No. 83-50, "Failure of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, August 1, 1983.

15. IE Information Notice No. 83-76, "Reactor Trip Breaker Malfunctions (Undervoltage Trip Devices on GE Type AK-2-25 Breakers)," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, November 2, 1983.

16. IE Bulletin No. 84-02, "Failures of General Electric Type HFA Relays in Use in Class 1E Safety Systems," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, March 12, 1984.

17. IE Information Notice No. 84-20, "Service Life of Relays in Safety-Related Systems," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, March 21, 1984.

18. IE Bulletin No. 85-02, "Undervoltage Trip Attachments of Westinghouse DB-50 Type Reactor Trip Breakers," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, November 5, 1985.

19. IE Information Notice No. 85-58, "Failure of a General Electric Type AK-2-25 Reactor Trip Breaker," U.S. Nuclear Regulatory Commission, Office of Inspection and Enforcement, Washington, DC, July 17, 1985, Supplement 1, November 19, 1985.

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33. NRC Information Notice No. 88-45, "Problems in Protective Relay and Circuit Breaker Coordination," U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, DC, July 7, 1988.

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35. NRC Bulletin No. 88-10, "Nonconforming Molded-Case Circuit Breakers," U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, DC, November 22, 1988.

36. NRC Information Notice No. 88-98, "Electrical Relay Degradation Caused by Oxidation of Contact Surfaces," U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, DC, December 19, 1988.

37. NRC Information Notice No. 90-41, "Potential Failure of General Electric Magne-Blast Circuit Breakers and AK Circuit Breakers," U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Washington, DC, June 12, 1990.

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As part of the NRC Nuclear Plant Aging Research (NPAR) Program, a comprehensive aging assessment was made of relays and circuit breakers. Relays and circuit breakers are important nuclear power plant equipment which are susceptible to degradation with time.

This is a Phase II NPAR report which follows the NPAR strategy. Tests on naturally aged and degraded relays and circuit breakers were performed, in-situ measurements made and current and improved methods for inspection, surveillance and monitoring (ISM) evaluated. Significant results described in this report were the identification of inspection, surveillance and monitoring methods which provide a higher level of assurance that aging will be detected and mitigated. The potential exists that implementation of the improved methods in nuclear plants would minimize the impact of aging and result in more cost effective maintenance on relays and circuit breakers.

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