NUREG/CR-5812
BNL-NUREG-52309

Managing Aging in Nuclear Power Plants: Insights From NRC Maintenance Team Inspection Reports

Prepared by
A. Fresco, M. Subudhi, W. Gunther, E. Grove, J. Taylor

Brookhaven National Laboratory

Prepared for
U.S. Nuclear Regulatory Commission

AVAILABILITY NOTICE

Availability of Reference Materials Cited in NRC Publications

Most documents cited in NRC publications will be available from one of the following sources:

1. The NRC Public Document Room, 2120 L Street, NW., Lower Level, Washington, DC 20555-0001

2. The Superintendent of Documents, U.S. Government Printing Office, Mail Stop SSOP, Washington, DC 20402-9328

3. The National Technical Information Service, Springfield, VA 22161

Although the listing that follows represents the majority of documents cited in NRC publications, it is not intended to be exhaustive.

Referenced documents available for inspection and copying for a fee from the NRC Public Document Room include NRC correspondence and internal NRC memoranda; NRC bulletins, circulars, information notices, inspection and investigation notices; licensee event reports; vendor reports and correspondence; Commission papers; and applicant and licensee documents and correspondence.

The following documents in the NUREG series are available for purchase from the GPO Sales Program: formal NRC staff and contractor reports, NRC-sponsored conference proceedings, international agreement reports, grant publications, and NRC booklets and brochures. Also available are regulatory guides, NRC regulations in the *Code of Federal Regulations*, and *Nuclear Regulatory Commission Issuances*.

Documents available from the National Technical Information Service include NUREG-series reports and technical reports prepared by other Federal agencies and reports prepared by the Atomic Energy Commission, forerunner agency to the Nuclear Regulatory Commission.

Documents available from public and special technical libraries include all open literature items, such as books, journal articles, and transactions. *Federal Register* notices, Federal and State legislation, and congressional reports can usually be obtained from these libraries.

Documents such as theses, dissertations, foreign reports and translations, and non-NRC conference proceedings are available for purchase from the organization sponsoring the publication cited.

Single copies of NRC draft reports are available free, to the extent of supply, upon written request to the Office of Administration, Distribution and Mail Services Section, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

Copies of industry codes and standards used in a substantive manner in the NRC regulatory process are maintained at the NRC Library, 7920 Norfolk Avenue, Bethesda, Maryland, for use by the public. Codes and standards are usually copyrighted and may be purchased from the originating organization or, if they are American National Standards, from the American National Standards Institute, 1430 Broadway, New York, NY 10018.

NUREG/CR-5812
BNL-NUREG-52309

Managing Aging in Nuclear Power Plants: Insights From NRC Maintenance Team Inspection Reports

Manuscript Completed: August 1993
Date Published: December 1993

Prepared by
A. Fresco, M. Subudhi, W. Gunther, E. Grove, J. Taylor

S. K. Aggarwal, NRC Program Manager

Brookhaven National Laboratory
Upton, NY 11973

Prepared for
Division of Engineering
Office of Nuclear Regulatory Research
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
NRC FIN A3270

ABSTRACT

A plant's maintenance program is the principal vehicle through which age-related degradation is managed. From 1988 to 1991, the NRC evaluated the maintenance program of every nuclear power plant in the United States. Forty-four out of a total of 67 of the reports issued on these in-depth team inspections were reviewed for insights into the strengths and weaknesses of the programs as related to the need to understand and manage the effects of aging on nuclear plant systems, structures, and components. Relevant information was extracted from these inspection reports and sorted into several categories, including Specific Aging Insights, Preventive Maintenance, Predictive Maintenance and Condition Monitoring, Post Maintenance Testing, Failure Trending, Root Cause Analysis and Usage of Probabilistic Risk Assessment in the Maintenance Process. Specific examples of inspection and monitoring techniques successfully used by utilities to detect degradation due to aging have been identified.

The information also was sorted according to systems and components, including: Auxiliary Feedwater, Main Feedwater, High Pressure Injection for both BWRs and PWRs, Service Water, Instrument Air, and Emergency Diesel Generator Air Start Systems, and emergency diesel generators, electrical components such as switchgear, breakers, relays, and motor control centers, motor operated valves and check valves. This information was compared to insights gained from the Nuclear Plant Aging Research (NPAR) Program. Attributes of plant maintenance programs where the NRC inspectors felt that improvement was needed to properly address the aging issue also are discussed.

CONTENTS

CONTENTS (Cont'd)

CONTENTS (Cont'd)

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

A plant's maintenance program is the principal vehicle through which age-related degradation is managed. From 1988 to 1991, the NRC evaluated the maintenance program of every nuclear power plant in the United States. The NRC issued 67 reports on these in-depth team inspections, one for each plant site. Forty-four of these reports were selected and reviewed for insights into the strengths and weaknesses of the programs as they relate to understanding and managing the effects of aging on nuclear power plant systems, structures, and components. Relevant information was extracted and sorted into several categories. Specific examples of inspection and monitoring techniques successfully used by utilities to detect degradation due to aging were identified. The information also was sorted according to a selected number of systems and components. Attributes of plant maintenance programs where the NRC inspectors felt that improvement was needed to properly address the aging issue also are discussed.

The NRC staff assessed the maintenance programs at every nuclear power plant site in the country. As a result, a large database of maintenance-related information was made available which, upon extraction and reorganization, could be presented to those individuals concerned with managing aging-related degradation of nuclear power plant systems and components. The database lends itself more to qualitative rather than quantitative evaluation; thus, the focus of this report is on providing primarily qualitative assessments of the effectiveness of the programmatic activities, and also on the effectiveness of those programmatic activities with respect to s[illegible]d systems and components. A quantitative assessment showed no apparent correlation with plant age.

Six broad programmatic categories were focussed upon as essential activities to address the management of aging:

- Specific Aging Insights
- Preventive Maintenance
- Predictive Maintenance and Condition Monitoring
- Post-Maintenance Testing
- Failure Trending
- Root Cause Analysis

A seventh category, Usage of Probabilistic Risk Assessment (PRA) in the Maintenance Process, was chosen to examine the extent to which time-dependent failure rates for system components have been used by the utilities in the modeling of plant-specific PRAs.

In addition to the seven programmatic categories, the database also was cross-sorted by specific plant systems and components. The systems chosen are:

- Auxiliary Feedwater
- Feedwater
- High Pressure Injection
- Service Water
- Instrument Air and Emergency Diesel Generator Air Start Systems and Compressors

The components are:

- Emergency Diesel Generators
- Electrical Components: Breakers, Switchgear, Relays, and Motor Control Centers (MCCs)
- Motor-Operated Valves
- Check Valves

Substantial insights were gained from analyzing all of the categories. Notable positive features and areas requiring improvement were identified. For the systems and components, the insights were compared to the results from the Nuclear Plant Aging Research (NPAR) Program.

With regard to the specific programmatic findings, although several notable practices were evident, such as a 13-week "rolling" maintenance schedule in which an entire train of safety-related components is taken out of service for maintenance and surveillance testing and the MESAC, or micro-electronic surveillance and calibration system, designed and developed at the Braidwood plant to dynamically test instrument systems, the number and extent of weaknesses in all areas leads to the conclusion that programmatic maintenance activities generally require significant improvement.

For maintenance activities of specific systems, there were serious failures in periodic testing of, or in incorporating vendor recommendations for, Auxiliary Feedwater pumps and turbines. Preventive maintenance was often poor for Instrument Air and Emergency Diesel Generator Air Start systems and compressors.

Poor maintenance practices were noted for components such as emergency diesel generators, breakers, and switchgear. Overall improvement was shown with respect to motor-operated valves and check valves.

The general conclusion is that the management of aging is typically not adequately addressed by existing maintenance programs. This conclusion is reached by considering the overall lack of specific aging management programs and notable deficiencies in preventive and predictive maintenance, post-maintenance testing, failure trending, and root cause analysis. We believe that widespread implementation of the many positive maintenance activities highlighted in this report, as well as a direct effort to improve the management of aging, would enhance the effectiveness of maintenance programs, and thereby, further improve the level of safety of nuclear power plants.

ACKNOWLEDGEMENTS

The authors wish to express their appreciation to their colleagues Philip Rose and Sonja Santos for their invaluable assistance with the preparation of the background data file input, organization, and assessment. Adele DiBiasio provided valuable input on surveillance and post-maintenance testing regulatory requirements. Alice Costantini, Kathleen Nasta, and Mary Wigger displayed superb word processing and organizational skills to produce this report in the proper format. Finally, appreciation is due to the NRC Program Manager, Satish Aggarwal, for his technical guidance and direction.

1.0 INTRODUCTION

Assuring the safe operation of a nuclear power plant depends, to a large extent, on how effectively one understands and manages the aging degradation that occurs in structures, systems, and components (SSCs). During the plant's original licensing process, the utilities and the regulatory agency use all available sources (such as vendor recommendations, equipment qualification documentation, consensus industry standards, industry practices) to determine that during the life of a plant all SSCs remain operational to accomplish their design functions. Utility equipment qualification (EQ) programs establish requirements for certain safety-related SSCs and outline the operational and maintenance practices that should prevent any such failure during the life of the component. These practices include periodic testing and inspection of components, replacement and refurbishment, analysis of parameters for predicting the future condition of components, development of procedures, data bases and trending, and use of advanced techniques of reliability centered maintenance such, as thermographic imaging.

After over two decades of experience for the commercial nuclear power plant industry, NRC inspection reports, 10 CFR Part 21 reports by vendors, NRC Generic Letters, Bulletins, Information Notices, and aging assessments of nuclear components and systems have indicated that failures of SSCs, including safety-related SSCs, do occur in spite of all the activities imposed by the original licensing requirements. Thus, the NRC implemented a team inspection program to evaluate and assess the current maintenance practices at all nuclear power plant facilities.

1.1 NRC Maintenance Policy and the Maintenance Team Inspections (MTIs)

From 1988 to 1991, the staff of the Nuclear Regulatory Commission conducted Maintenance Team Inspections (MTIs) at commercial nuclear power plants to determine the need for a maintenance rule by inspecting and evaluating the effectiveness of licensee maintenance activities. A detailed report was issued on the results of each inspection which described the strengths and weaknesses of the maintenance program and its implementation. The NRC's goals are described in one of the MTI reports:[1]

> The Nuclear Regulatory Commission considers effective maintenance of equipment and components a major aspect of ensuring safe nuclear plant operation and has made this area one of the NRC's highest priorities. In this regard, the Commission issued a Policy Statement dated March 23, 1988,[2] that states, "it is the objective of the Commission that all components, systems, and structures of nuclear power plants be maintained so that plant equipment will perform its intended function when required. To accomplish this objective, each licensee should develop and implement a maintenance program which provides for the periodic evaluation, and prompt repair of plant components, systems, and structures to ensure their availability."
>
> To ensure effective implementation of the Commission's maintenance policy, the NRC staff is undertaking a major program to inspect and evaluate the effectiveness of licensee maintenance activities. As part of this inspection activity, the current inspection was performed in accordance with guidance provided in NRC Temporary Instruction 2515/97, Maintenance Inspection Guidance, dated November 3, 1988.[3] The temporary instruction includes a "Maintenance Inspection Tree" that identifies the major elements associated with effective maintenance. The tree was designed to ensure that all factors related to maintenance are evaluated.

Subsequently, in August 1989, the NRC issued a draft regulatory guide, DG-1001, concerning maintenance programs for nuclear power plants.[4]

The maintenance inspection teams consisted of a team leader, two reactor project engineers and a radiation specialist all from the regional office and two engineers from NRC headquarters. The inspection schedule covered 6 weeks: 1 week of preparation, 2 weeks of on-site inspection, 1 week of in-office inspection, and 2 weeks of documentation and report writing.

The inspections were performance based, directed toward evaluating equipment conditions; observing in-process maintenance activities; reviewing equipment histories and records; and evaluating performance indicators, maintenance control procedures, and the overall maintenance program. The team selected certain systems and directed the inspection toward determining whether those systems were being properly maintained and assessing if the current maintenance system would ensure proper maintenance in the future.

The systems selected for evaluation were usually based on some or all of the following criteria:

- Known industry problems
- Review of plant-specific Licensee Event Reports (LERs) and other plant-specific problems
- Review of NRC Bulletins and Notices
- Review of plant-specific deficiency reports
- Discussions with resident inspectors
- Probabilistic risk assessment (PRA)-based information provided by the Office of Nuclear Reactor Regulation (NRR)
- Inspector's experience

The teams performed walkdown inspections of portions of the selected systems to determine the material condition of the equipment. In addition, maintenance history records for the last two years were reviewed for any adverse trends. The Nuclear Plant Reliability Data System (NPRDS) data were also reviewed for the selected systems. In the review of equipment history records, any questionable trends were examined in detail to determine if equipment was being properly maintained. The teams also observed general housekeeping and equipment condition for a large part of the plant. A review and summary by the NRC of the results of 31 site inspections available through fiscal year 1989 was previously published.[5]

After all the MTIs were completed, on June 28, 1991, the NRC staff released SECY 91-110, "Staff Evaluation and Recommendation on Maintenance Rulemaking."[6] The NRC formally promulgated the "Maintenance Rule" on July 10, 1991, as 10CFR50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."[7] The rule formally takes effect on July 10, 1996.

In June 1993, the NRC published Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."[8] This guide in turn endorses guidance developed by the industry as provided in NUMARC 93-01.[9]

1.2 Goals of the Nuclear Plant Aging Research (NPAR) Program with Respect to the MTI Reports

In addition to environmental factors such as elevated temperature, humidity, etc., aging can be accelerated by inadequate maintenance, improper or too frequent testing, or excessive cycling from routine or abnormal operations. However, a maintenance program has important elements, such as preventive maintenance, reliability-centered maintenance, record keeping, and trending for detecting and mitigating age-related degradation.

The goal of this project is to glean information from the MTI report to understand aging and to identify important elements of maintenance programs that can effectively manage aging. Because the primary objectives of these team inspections were not focussed directly towards the aging that might be occurring in nuclear power plants, information pertaining to aging was extracted systematically to evaluate the understanding and management of these aging problems. (No quantitative assessment on the subject of assessing the utilities performance in assuring the plant operability against aging is attempted, because the MTI reports may not have complete information relating to the aging issues.) However, both positive and negative elements, as found in these MTI reports were analyzed to provide a qualitative assessment of the current industry practices in understanding and managing the aging problems. In some instances, specifically for components and systems, these results are compared with that from the aging studies performed under the NRC's NPAR program.

In support of the NPAR Program, the MTI reports therefore were reviewed with the following objectives in mind:

(1) To identify those portions of the maintenance program important for understanding and managing aging.

(2) To evaluate the specific strengths and weaknesses noted in utility maintenance programs for their effect on the ability of the plant to manage aging.

(3) To describe the types of preventive maintenance activities and condition monitoring techniques used which address plant aging concerns.

(4) To determine whether there is a recognizable quantitative pattern of strengths and weaknesses correlated to plant age and reactor type.

To achieve these objectives, information from each MTI report was compiled into a computerized data base. This information included observations by the inspectors related to the concept of understanding and managing aging, such as:

- specific references to equipment aging problems,
- predictive maintenance and condition monitoring techniques,
- selected preventive maintenance activities,
- use of equipment manufacturer's information,
- post-maintenance testing activities,
- evaluation of failure trending and root cause analysis programs, and
- prioritization of maintenance activities.

There are a total of 67 MTI reports, one for each site. (Oyster Creek was not actually inspected. Rather, the NRC extracted maintenance-related results from other NRC team inspections at that plant.)[†] Similar to the NRC summary, BNL also published a summary of preliminary results based on 26 MTI reports.[10] For the final study, BNL selected a representative sample of 44 MTI reports which were issued through the end of 1990. These reports correspond to 29 Westinghouse PWR units, 16 Combustion Engineering PWR units, 1 B&W PWR unit, and 22 General Electric BWR units. Tables 1.1 to 1.3 show the names of the units and the corresponding report numbers. BNL categorized each relevant finding as a positive aspect or attribute, an observation, a deficiency, a failure, or a violation. The latter was solely based on whether the NRC cited the finding as an example of a violation. Each category was tabulated, separated into Westinghouse, Combustion Engineering (CE), Babcock & Wilcox (B&W), and General Electric (GE), and all plants combined by order of decreasing age. Specific qualitative findings were selected based on their importance either as examples of good or poor practices or experiences.

This report is organized in the following manner. Section 2.0 discusses the methodology of both the NRC inspections and the current study. Section 3.0 discusses each of the programmatic categories, while Section 4.0 details the insights on the systems and components selected for review. Section 5.0 gives a general summary and the conclusions and Section 6.0 lists the references.

Appendix A contains a sample list of the coding scheme that was used to categorize the findings extracted from the MTI reports; Appendix B illustrates a sample of the data base; Appendix C shows the results of the quantitative analysis; Appendix D lists the important findings pertaining to the programmatic activities while Appendix E gives the findings for the systems and components.

[†] Private communication, A. Fresco, BNL, with J. Sharkey, U.S. NRC, November 12, 1991.

Table 1.1 Maintenance Team Inspection Reports Reviewed for Westinghouse PWR Plants

Plant Name	Commercial Operation Date*	MTI Report No.**	MTI Report Date
Yankee Rowe	07/61	50-029/90-81	09/28/90
Haddam Neck	01/68	50-213/90-80	12/05/90
San Onofre 1,2,3+	01/68	50-206/89-16 50-361/89-16 50-362/89-16	08/22/89
Ginna	07/70	50-244/90-80	07/12/90
Robinson	03/71	50-261/90-10	08/07/90
Surry 1,2	12/71	50-280/90-07 50-281/90-07	05/18/90
Zion 1,2	12/73	50-295/89018 (DRS) 50-304/89017 (DRS)	08/30/89
Prairie Island 1,2	12/73	50-282/89029 (DRS) 50-306/89029 (DRS)	03/15/90
Indian Point 2	08/74	50-247/89-80	08/20/89
Cook 1,2	08/75	50-315/89031 50-316/89031	03/01/90
Indian Point 3	08/76	50-286/89-80	07/05/89
Salem 1,2	06/77	50-272/90-200 50-311/90-200	06/07/90
North Anna 1,2	06/78	50-338/89-200 50-339/89-201	08/08/89
Sequoyah 1,2	07/81	50-327/90-25 50-328/90-25	11/01/90
McGuire 1,2	12/81	50-369/89-15 50-370/89-15	09/07/89
Millstone 3	04/86	50-423/89-80	08/31/89
Shearon Harris 1	05/87	50-400/89-16	10/30/89
Braidwood 1,2	07/88	50-456/90008 (DRS) 50-457/90008 (DRS)	06/14/90
South Texas 1,2	08/88	50-498/90-01 50-499/90-01	04/24/90

*For multiple units, Commercial Operation Date corresponds to the first unit on site.
**One MTI Report for multiple units.
+Unit 1 is Westinghouse plant.

Table 1.2. Maintenance Team Inspection Reports Reviewed for B&W and CE PWR Plants

Plant Name	Commercial Operation Date*	MTI Report No.**	MTI Report Date
San Onofre 1,2,3+	01/68	50-206/89-16 50-361/89-16 50-362/89-16	08/22/89
Palisades	12/71	50-255/88020 (DRS)	01/10/89
Maine Yankee 1	12/72	50-309/88-80	01/18/89
Ft. Calhoun 1	09/73	50-285/89-01	07/06/89
Arkansas One 1,2	12/74	50-313/88-36 50-368/88-36	02/07/89
Rancho Seco 1	04/75	50-312/89-01	03/24/89
Calvert Cliffs 1,2	05/75	50-317/90-80 50-318/90-80	04/02/90
Millstone 2	12/75	0-336/89-80	08/31/89
St. Lucie 1,2	12/76	50-335/89-24 50-389/89-24	01/10/90
Waterford 3	09/85	50-382/89-01 50-316/89031	03/14/89
Palo Verde 1,2,3	01/86	50-528/89-28 50-529/89-28 50-530/89-28	10/26/89

*For multiple units, Commercial Operation Date corresponds to the first unit on site.
**One MTI Report for multiple units.
+Units 2,3 are CE plants.

Table 1.3. Maintenance Team Inspection Reports Reviewed for GE BWR Plants

Plant Name	Commercial Operation Date*	MTI Report No.**	MTI Report Date
Nine Mile Point 1,2	12/69	50-220/88-80 50-410/88-80	01/24/89
Dresden 2,3	06/70	50-237/88029 (DRS) 50-249/88030 (DRS)	04/04/89
Millstone 1	03/71	50-245/89-80	08/31/89
Vermont Yankee	11/72	50-271/89-80	06/01/89
Peach Bottom 2,3	07/74	50-277/88-17 50-278/88-17	10/06/88
Cooper 1	07/74	50-298/89-31	01/29/90
Duane Arnold	02/75	50-331/88023 (DRS)	07/02/89
Fitzpatrick	07/75	50-333/90-80 (DRS)	07/16/90
Hatch 1,2	12/75	50-321/89-02 50-366/89-02	05/22/89
La Salle 1,2	01/84	50-373/89010 (DRS) 50-374/89010 (DRS) 50-316/89031	06/27/89
Grand Gulf 1	07/85	50-416/88-21	01/04/88
Limerick 1,2	02/86	50-352/89-80 50-353/89-80	03/21/89
River Bend 1	06/86	50-458/89-04	12/05/89
Hope Creek	12/86	50-354/89-80 50-328/90-25	01/31/90
Clinton	04/87	50-461/89003	05/10/89
Perry 1	11/87	50-440/90012 (DRS)	11/13/90
Fermi 2	01/88	50-440/90012 (DRS)	11/13/90

*For multiple units, Commercial Operation Date corresponds to the first unit on site.
**One MTI Report for multiple units.

2.0 DISCUSSION OF METHODOLOGY

2.1 Methodology of the NRC Maintenance Team Inspections

The MTIs were oriented toward analyzing the performance of maintenance activities rather than toward compliance with regulations or identification of violations. However, whenever necessary, violations were cited against 10 CFR 21, "Reporting of Defects and Noncompliance," 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and also against Technical Specifications. Most of the negative findings were considered to be deficiencies and not formal violations, so that the severity level of the deficiencies was not quantified, except when they were cited as examples of violations. The NRC MTI reports are comprehensive documents, some of which may be 70 or more pages long. Most, if not all, were prepared by different teams of NRC inspectors so that the same team usually did not perform more than one inspection. According to A. T. Gody, et. al.,[5] the maintenance inspection program was a combination of the NRC's past inspections, pulled together for a comprehensive look at maintenance and related activities. The inspection tree was used in previous inspection programs, but was modified specifically for the MTI effort.

As noted in Section 1.1, the inspections were conducted using the guidance provided in NRC Temporary Instruction 2515/97, "Maintenance Inspection Guidance," dated November 3, 1988, which includes a Maintenance Inspection Tree (Figure 2.1). Figure 2.1 shows the three major areas of utility maintenance programs which were evaluated:

I. Overall Plant Performance Related to Maintenance,
II. Management Support of Maintenance, and
III. Maintenance Implementation.

Under each major area, several elements were evaluated, rated, and color-coded using the following guidelines:

Good" Performance (GREEN): Overall, better than adequate; shows more than minimal effort; can have a few minor areas that need improvement.

"Satisfactory" or "Adequate" Performance (YELLOW): Adequate, weaknesses may exist, could be strengthened.

"Poor" Performance (RED): Inadequate or missing.

"Unrated" (BLUE): Not evaluated.

At the conclusion of the inspection, the inspection team judged the adequacy of the maintenance program, using the inspection tree in Figure 2.1. In general, the top half of the box (element) was rated depending on whether the element was in place, and the bottom half was rated depending on how well the element was being implemented.

The inspection tree, which contains 43 individual elements, includes several inspection sub-topics which we believe are directly relevant to the management of aging that will be discussed further in the next section.

2.2 Methodology of the Current Study

One element that is directly relevant to the management of aging, as shown in Figure 2.1, is Element 1.1, "Historic Data," which consists of reliability as represented by reactor trips, engineered safety feature (ESF) actuations, outages, Technical Specification violations, and failures on demand. These can often result from aging-related degradation. Table 2.1 provides a rationale for relating all of the other elements in the inspection tree to the management of aging.

In the majority of cases, the MTI reports available from the Public Documents Room did not contain the inspection trees. Because the trees are essentially qualitative and quantitative assessments of the broader categories of utility maintenance programs, they were not considered essential to the goals of this particular study.

To achieve the objectives mentioned in the Introduction, we developed a strategy to compile and sort the diverse information from the MTI reports, reflecting the aging-related elements identified in Table 2.1, to yield both quantitative and qualitative insights. A pattern of positive aspects and deficiencies in the reports was identified, and we placed the results into seven general categories, shown in Table 2.2, concerning information or activities important for managing aging. These categories, except for the PRA category that is an indirect influence, were considered to directly affect the management of aging concerns. They are in general agreement with the terminology associated with maintenance, as described in an EPRI Draft Report on common aging terminology for nuclear power plants.[11]

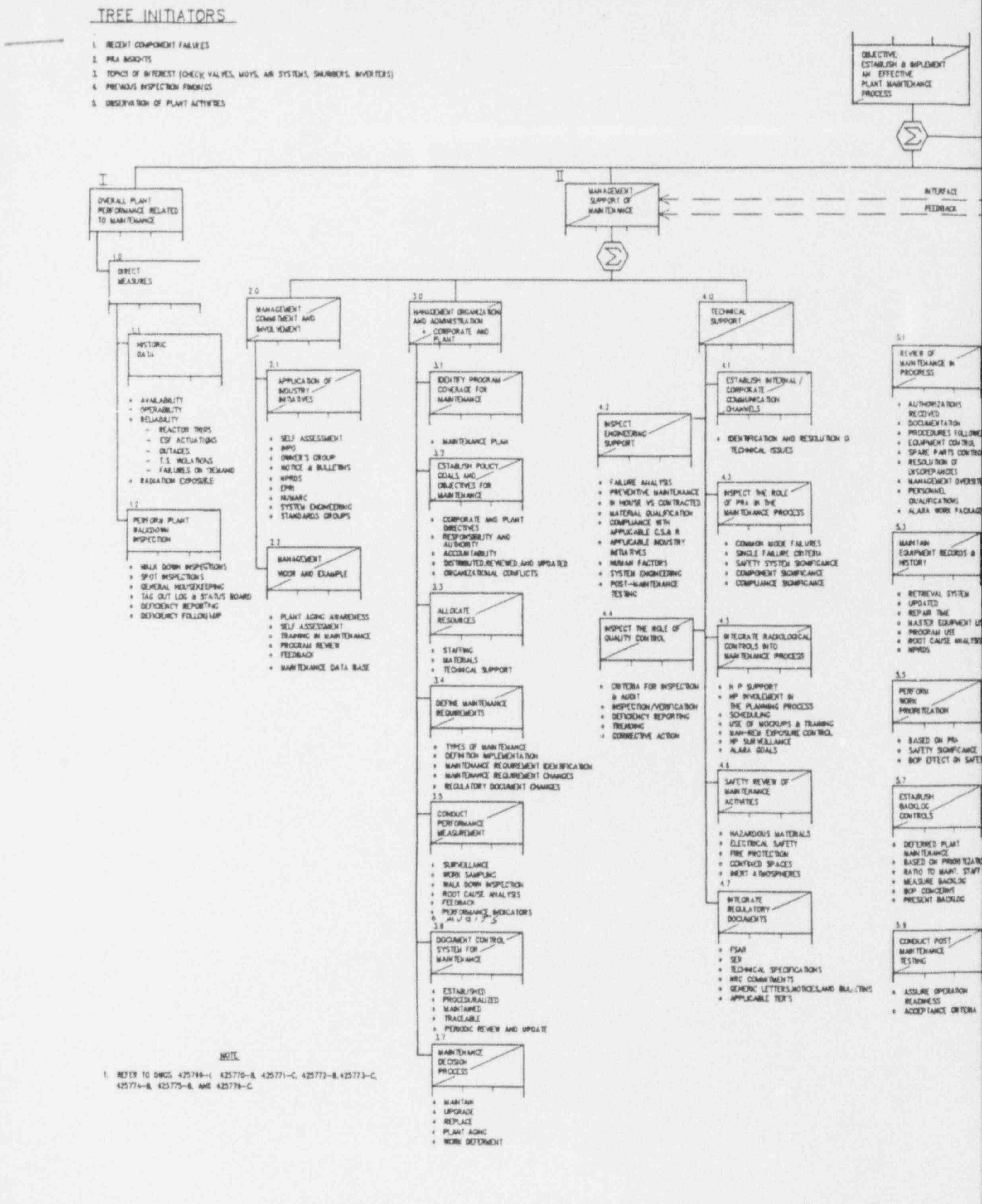
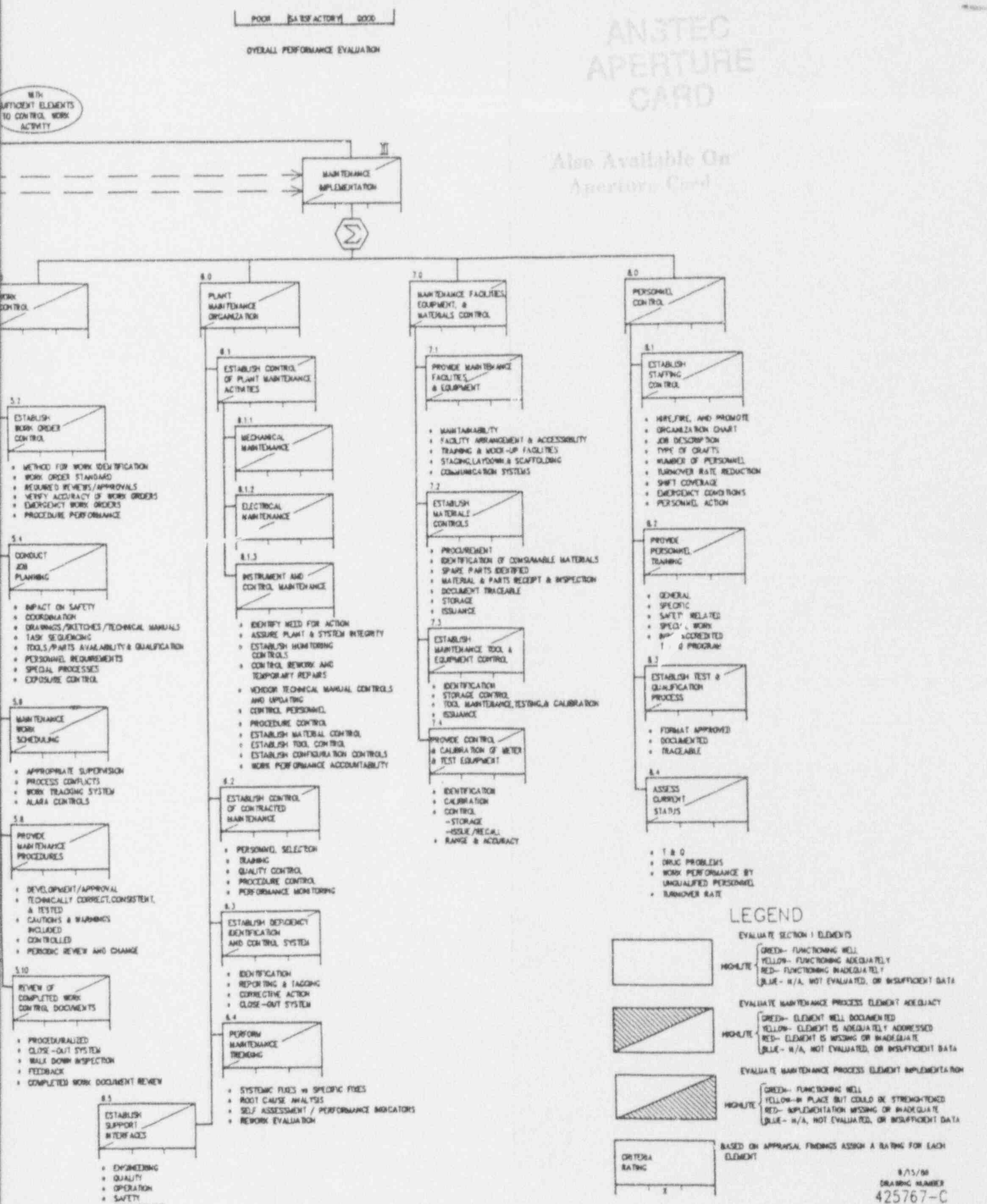


Figure 2.1. Maintena



ce Inspection Tree

9402220158-01

Table 2.1. Correlation of Certain Maintenance Inspection Tree Elements with the Management of Aging

Tree Element	Relationship to Management of Aging
I. Overall Performance Related to Maintenance 1.0 Direct Measures 1.1 Historic Data • Failures on Demand	Any increase in the failure rate on demand of particular systems and components is a key indicator of potential aging-related problems.
1.2 Perform Plant Walkdown Inspection • Walkdown Inspections	Walkdown inspections can provide a direct indication of aging-related degradation such as corrosion of pumps, valves, electrical contacts, and overall plant material condition.
II. Management Support of Maintenance 2.0 Management Commitment & Involvement 2.1 Application of Industry Initiatives • Notices and Bulletins • NPRDS	The degree of management responsiveness to industry and vendor notices and bulletins, as well as input to and use of NPRDS data, can have a direct impact on the mitigation of aging effects.
2.2 Management Vigor and Example • Plant Aging Awareness	The degree to which plant management recognizes aging of systems and components as a real concern has an obvious effect on the direction of maintenance activities, and subsequently on safe plant operation.
3.0 Management Organization and Administrative • Corporate and Plant	Interaction between corporate and plant management is essential to recognize and mitigate the effects of aging throughout the life of the plant.
3.5 Conduct Performance Measurement • Root Cause Analysis (RCA)	RCA is an integral part of the process of identification of aging concerns. Simple identification of numerical trends is not adequate to detect degradation.
3.7 Maintenance Decision Process • Plant Aging	Incorporation of plant aging concerns into the maintenance decision process can lead to reduced failure rates and safer plant operation due to the replacement or repair of components which are likely to fail at unacceptable rates.

Table 2.1. (Cont'd)

Tree Element	Relationship to Management of Aging
4.0 Technical Support	Engineering support is another criticalfunction to the management of aging.
4.2 Inspect Engineering Support • Failure Analysis	*Failure Analysis* is the systematic process of determining and documenting the mode, mechanism, causes and root cause of the failure of a system, structure, or component.
• Preventive Maintenance	*Preventive Maintenance* directly mitigates the effects of aging by minimizing the failure of systems and components due to aging-related and other causes.
• Post-Maintenance Testing	*Post-Maintenance Testing* is important to establish a baseline reference point from which not only aging-related but other forms of degradation in system and component performance can be monitored.
4.4 Inspect Role of Quality Control • Trending	Trending can apply to both the results of predictive maintenance techniques, in which case observed degradation can be often interpreted as a direct result of aging effects, and to the direction of component and system failures with time. The latter may not directly indicate aging-related degradation.
4.7 Integrate Regulatory Documents • Generic Letter, Notices & Bulletins	Similar to Element 2.1 on management responsiveness to industry and vendor notices and bulletins, the degree of management responsiveness to NRC regulatory documents, as exemplified by incorporation into the plant maintenance program, can have a direct impact on mitigation of aging effects.
III. Maintenance Implementation	
5.0 Work Control	
5.3 Maintain Equipment Records & History • Root Cause Analysis	To successfully mitigate the effects of aging degradation of systems and components, it is essential that adequate documentation be provided and maintained to allow accurate root cause analysis.
• NPRDS	Consistent input and reference to the NPRDS also is important to facilitate accurate RCA.
5.9 Conduct Post-Maintenance Testing • Assure Operational Readiness • Acceptance Criteria	Together with the Engineering Support requirements mentioned in 4.2, the acceptance criteria also are crucial for monitoring aging-related degradation.

Table 2.1. (Cont'd)

Tree Element	Relationship to Management of Aging
5.10 Review of Completed Work Control Documents • Completed Work Document Reviews	The proper entry of "As Found" and "Failure Cause" information into the completed maintenance work packages is essential for trending and root cause analysis, which, in turn, are essential to monitor aging-related degradation.
6.0 Plant Maintenance Organization	
6.4 Perform Maintenance Trending	As discussed for 4.4, trending is an important aspect in the management of aging.
• Root Cause Analysis	Root Cause Analysis is necessary to properly identify aging-related degradation as opposed to other failure causes.
• Rework Evaluation	It also is important to identify as rework, failures which have occurred within a very short time after maintenance has been performed, which may therefore be attributed to poor maintenance practices, or simply repetitive failures of components regardless of the length of time since the last maintenance was performed.
7.0 Maintenance Facilities, Equipment & Materials Control	
7.2 Establish Materials Controls • Storage	Proper administrative control of environmental conditions for spare parts which have a limited shelf-life, such as certain elastomers used for gaskets, is an integral part in the management of the effects of aging.

The findings were then categorized based on whether the NRC determined them to be a positive or negative aspect of the utility's maintenance program. Thus, we established the following sub-categories, shown in Table 2.3.

A sample of the definitions used in the coding scheme is shown in Appendix A. The coding scheme became necessary because, for each general category, such as AGI or PCM, each finding pertained to a specific area and often involved a system, component, structure, or other aspect. The specific area of the finding was often limited to one or two major categories. For example, the specific area documentation was mostly applicable to trending and root cause analysis. Thermography and vibration were usually associated with the general category of PCM, i.e., predictive maintenance and condition monitoring.

Once the coding scheme was decided upon, it became possible to categorize all of the significant aging-related findings from the MTI reports. The significant findings were entered into an information management database program entitled **askSam**.[12] The database was created by analyzing the MTI reports, extracting and categorizing the information and entering it into the database. A sample of the **askSam** file for the Calvert Cliffs Units 1 and 2 is shown in Appendix B. The findings on a particular topic often appeared on widely separated pages of the MTI reports, so that it was not always possible to cite one specific paragraph on one specific page. Some findings were generated by combining information from one or more separate sections of the reports.

The next objective was to create a useful quantitative analysis. We decided to count the findings: the positive aspects, observations, negative aspects, failures, and violations for each of the general categories. To show whether or not there was any direct correlation between the quality of the maintenance programs with the age of the plant or type of the reactor, the count for each of the major groupings was presented in descending order of older to newer plants for each reactor type such as

Table 2.2. Categories of Information or Activities Important for the Management of Aging

AGI	Specific aging-related insights or management responsiveness to aging concerns.
PMF	Preventive maintenance and incorporation of manufacturers' information.
PCM	Predictive maintenance and condition monitoring techniques.
PMT	Post maintenance testing.
TDA	Failure trending analysis.
RCA	Root cause analysis or failure analysis.
PRA	Use of Probabilistic Risk Assessment (PRA), by the utilities for maintenance and by the NRC for inspection, and/or prioritization of maintenance activities. This category also was considered to include Reliability Centered Maintenance (RCM).

Table 2.3 Categorization of Findings

ATB	Positive aspect or attribute.
OBS	Observation or neutral aspect.
DFC	Negative aspect or deficiency.
FLR	Failure, usually a direct reference to a specific system or component.
VLN	Violation.

Babcock & Wilcox (B&W) PWRs, and General Electric (GE) BWRs. An overall list of all plants in ascending order, regardless of reactor type, also is presented for each general category. The quantitative results are shown in Appendix C.

At this point, the issue of the usefulness of the quantitative analysis must be addressed. There are several important aspects of the MTI reports and the inspection process which must be discussed:

(1) As a result of the previously known problems and the problems identified during the inspection, the NRC inspection teams placed different emphasis on some topics at one plant as compared to another plant. For example, because of the problems identified with maintenance practices or procedures at one plant, less emphasis might have been placed on predictive maintenance and condition monitoring, while at another plant, these areas might have been described in great detail. As a result of the specific inspection requirements of each plant, the MTI reports vary significantly in emphasis and detail placed on particular topics.

(2) A typical MTI report describes both positive and negative aspects of a utility's maintenance program. However, in the majority of cases, the negative aspects are described in greater detail. Positive aspects are often described in general terms and may be broad statements on a major topic, such as whether or not a failure trending program is in place, and its effectiveness.

(3) In the BNL database, broad characterizations and specific aspects were considered equally as either positive aspects or deficiencies, so that a simple counting of the number of positive aspects and deficiencies would include both. Thus, there are usually more deficiencies cited in the BNL database than there are positive aspects. In the coding scheme, such differences

were identified, and a more refined counting could provide additional insights.

(4) Specific deficiencies were often cited as examples of one violation in the MTI reports. However, in the BNL database, such separate deficiencies were counted as separate violations, because the other examples of a violation were often not ageing-related.

(5) Several of the MTI reports contained a separate list of strengths and weaknesses in the utility's maintenance program. The aging-related ones usually corresponded to a positive aspect or deficiency cited in the BNL database. However, the BNL database often included additional findings which were described in greater detail in the body of the MTI reports, so that there is not a one-to-one correspondence.

(6) It was sometimes difficult to differentiate between positive aspects and observations or between deficiencies and observations. Sometimes an NRC inspector merely described the aspects of a program without indicating whether they were positive or negative. BNL characterized such cases as observations.

(7) The BNL coding scheme was really a backfit attempt to extract quantitative insights on both broad trends and specific findings appearing in the MTI reports. The MTI reports were not conceived or written to be used in a manner which would be ideal for the coding scheme.

(8) One MTI report was generated for each site. Some sites have two or three units, and the reactor types also may be completely different from one unit to the next. For data analysis purposes, because we often could not determine specifically which unit the NRC inspectors were referring to, the multi-unit sites with different reactor types were counted under each reactor type. For example, San Onofre 1, 2, and 3 consists of one Westinghouse PWR and two Combustion Engineering PWRs. Because we could not determine which unit was being referred to, the data were attributed to both Westinghouse and CE sites. When specifying the age of a reactor at a multi-unit site for data analysis, the commercial operations date of the first unit was always chosen. The overall effect of this action on the quantitative results was negligible because at only one site, San Onofre, was there a truly significant difference between the age of the first unit and the remaining two i.e., the difference is 15 years between Unit 1 and Unit 2.

(9) No attempt was made to account for utility rebuttals to the MTI reports, nor the NRC re-inspections at certain plants.

With proper consideration of the above, we believe that the quantitative data resulting from this study (Appendix C) provide some limited insights into the effects of maintenance on aging-related degradation. The data did not show any clear relationship to the age of the plants and we do not believe that any firm conclusions should be drawn from the data set. Thus, the data and associated insights for a few of the findings categories are presented in Appendix C of this report.

3.0 PROGRAMMATIC INSIGHTS

Managing aging of structures, systems, and components in nuclear power plants becomes increasingly more important as the plants become older. Both the nuclear industry and the NRC are striving to identify aging degradation before safety and reliability are affected. Lack of new plant orders and relicensing requirements for plants at the end of life have brought the aging issue to the forefront since the inception of the NPAR program in 1983. The results have provided a wealth of knowledge on this subject and have created an awareness of aging problems by the utilities and the NRC. Some of the research findings on the aging problems that have been identified through this and other NRC programs also have drawn the attention of international regulatory bodies such as the IAEA and the regulatory and utility sectors of countries, such as Japan, Germany, the United Kingdom, and France.

During the first 10 years of plant life, aging management in nuclear power plants is based primarily on the equipment qualification (EQ), vendor recommendations, good maintenance practices learned from fossil power plant operations, and engineering judgement. In particular, EQ requirements identify components which have a useful life less than the 40 year operating license period, and thus are components which require periodic replacement. As the nuclear industry matures, aging problems associated with various structures, systems, and components have surfaced and the focus has turned to activities such as new testing and diagnostic methods, preventive maintenance programs, and trending of component or system characteristics. Because aging is a common mode failure and can have adverse consequences if all similar components were to fail simultaneously, PRA studies have identified the importance of understanding and managing this aging concern, specifically in older plants.

The programmatic aspects of a good program that can effectively manage aging in nuclear power plants, include the following elements:

- an understanding of the aging problems
- developing an effective preventive maintenance program, which includes:

- predictive maintenance techniques
- condition monitoring methods
- post-maintenance testing methods
- trending aging parameters (as applicable to structures, systems, and components)
- root cause analysis of each failure event
- reliability analyses to monitor the aging management program

A qualitative overview on each of these topics from the reviews of the 44 MTI reports is presented in the following sub-sections. Because the database of these reports contains almost 2000 pages of information, it is a considerable task to present all the findings contained in these reports. However, we highlighted the strengths and weaknesses of the existing programs to manage aging within the nuclear industry. Appendix D describes some examples of each of these aspects cited in these reports to support the characterization of the status of the programmatic efforts which follow.

3.1 Specific Aging Management Insights

In general, the MTI reports provide substantial information on how plant maintenance programs address the aging of systems, components, and structures. This information includes the attitude of management toward aging and the specific maintenance program attributes, which address the detection or mitigation of degradation caused by aging. Actual descriptions of failed or degraded systems, components, or structures are considered, in most cases, to be specific references to equipment aging problems.

3.1.1 Qualitative Insights

Understanding the aging characteristics of structures, systems, and components requires a comprehensive knowledge of the age-sensitive materials, environmental and operational conditions that influence these materials, and other contributing factors such as maintenance activities, management support, human factors, training, and plant procedures. However, one can assess the aging characteristics of a component from its failure information and the type of maintenance which restored its normal design function(s). The MTI reports reviewed for this study have identified age-related failures or degradations of components and systems in a nuclear power plant. Table 3.1 summarizes typical aging problems that were noted for mechanical and electrical/I&C components. Based on a review of the degradations and failures of components that have occurred, the current preventative maintenance programs have not adequately managed aging in many instances.

Table 3.1. Typical Aging Problems in Nuclear Power Plant Components Identified in the MTI Reports

Mechanical	Electrical and I&C
Erosion/corrosion of valve & pump internals	Water in the SOV internals and EDG Air Start System
Corrosion of flanges	
Loose springs	Cracked surge ring brackets in large GE motors
Eroded stem hinge	Corrosion/discoloration in optical isolators due to aggressive chloride-containing cleaning solvent used to clean cabinets
Damaged rubber seat insert	Cracked insulation on a 4 KV bus bar
Peeling of coatings	Dirty/sticking contacts
Valve/pump packing leakage	Misaligned or broken contact arms
Moisture contamination of lube oil	Deteriorated cable insulation
Thru-wall leaks at weld joints in carbon steel piping	Set point drift of I&C devices
Rusty pipe supports	Burned coils
Hardened grease & dirt in auxiliary switch linkage in a 4.16 KV breaker	
Missing hand wheels	
Clogged strainers	
Rusty HX tubes	

Except for routine inspection activities, plants typically perform several preventive maintenance tasks at each refueling outage, including cleaning/lubricating electrical components, cleaning/lubricating valve stems, verifying MOV torque and limit switch settings, inspecting heat exchangers, sampling bearing oil, checking pump and valve packing, calibrating plant instrumentation, and conducting other condition monitoring tests.

Some plants have recently implemented other techniques to manage aging, which include reliability centered maintenance, vibration monitoring, thermography (infrared imaging), station battery specific gravity tests, timely replacement of parts with limited life, Electronic Characterization and Diagnostics (ECAD), protective trip testing of breakers, and upgrading safety class of equipment exhibiting frequent failures. Insulation resistance testing of rotating machinery, cables, and other insulating materials has been performed routinely to condition monitor the equipment. Because of the unavailability and obsolescence of spare parts, particularly I&C devices, many plants are replacing old units with new and more sophisticated devices.

There were areas noted for improvement with respect to management of aging in the present plant maintenance programs. For example, condition monitoring of rotating equipment (i.e., fan motors, dampers, actuators, metering device, fan belts) was often deferred, there were failures to test overspeed mechanisms of Auxiliary Feedwater pump turbines at the required interval and there were cases of improper torque switch settings in MOVs.

3.1.2 Conclusions on Specific Aging Insights

The plant specific insights in Appendix D, Section D.1, lead to certain observations and conclusions. Specifically, while some utilities appeared to assume a proactive stance to prevent aging-related failures of systems and components both safety-related and important balance of plant, others seemed to be taking a passive or reactive stance. Differing maintenance philosophies, financial resources, and the lack of regulatory requirements affect management's attention to aging concerns. One utility considered its plant license renewal program to be founded upon a strong maintenance program.

None of the utilities had a separate program to address the management of aging as a separate issue. Most, if not all, appeared to rely on their maintenance programs to indirectly address aging. Examples of slowness to respond or unawareness of aging concerns were noted in some cases.

Among the best responses to aging concerns was the program at Salem to replace the Service Water system piping with 6% molybdenum stainless steel over an extended period to 1995. At St. Lucie, the utility had a PM program to inspect and test the electrolytic capacitors in the 120 VAC inverters. Such electrolytic capacitors, which are used as smoothing filters for the output voltage, had been identified as having a limited life by the NPAR program in NUREG/CR-4564.[13]

Conversely, among the poorer responses to aging concerns were the slow corrective actions at Duane Arnold to replace Tuf-LOC Teflon coated fiberglass sleeve bearings in certain 4160 VAC GE-manufactured circuit breakers. In 1979, the manufacturer identified the bearings as subject to premature wear. Similarly, at La Salle and Prairie Island, both utilities were slow to respond to the notification by Limitorque of common mode failures of melamine torque switches in motor operated valves. The failure cause was post mold shrinkage affected by temperature and age.

Also noteworthy were the chronic problems which occurred in the Emergency Diesel Generator Air Start (EDGAS) System at Surry because of leaking check valves and compressors which required frequent in-head replacement. All six discharge check valves were recently replaced and all six compressors were being replaced. The problems occurred because of high moisture content in the air entering the compressors.

In summary, our overall impression after reviewing the 44 MTI reports is that the process of taking a forward looking approach to managing aging is in the initial stages.

3.2 Preventive Maintenance Insights

Preventive Maintenance (PM) is the periodic, predictive, or planned maintenance of a structure, system, or component (SSC), which is performed before failure, to extend service life by controlling degradation or failure.

PM is divided into three broad categories that are distinguished by the means used to determine when to perform the required maintenance. The first **Periodic Maintenance** is a form of PM consisting of servicing, inspecting, testing, and replacing SSCs at predetermined intervals of calendar time, operating time, or number of cycles. The second, **Predictive Maintenance** is a form of PM that is performed periodically or continuously to monitor, inspect, test, diagnose or trend the performance or condition indicators of a SSC. The results indicate or forecast functional ability or the nature and schedule of planned maintenance before failure. The third, **Planned Maintenance**, is a form of PM consisting of refurbishment, overhaul, or replacement that is scheduled and performed before system, structure, or component failure. As used in this report, PM refers only to Periodic or Planned Maintenance. Predictive Maintenance will be discussed in the next section.

Some of the measures of the effectiveness of maintenance are the following:

- the performance of equipment after maintenance (deteriorating performance should be improved)
- the changes noted from trending and comparing failure and degradation (adverse failure/degradation rates should be corrected), and
- the amount of rework required after original maintenance (effective maintenance should require minimal correction).

If a PM program effectively considers the failure modes, mechanisms and causes of aging, and implements programs to control their effects at an acceptable level, then it is managing aging. The MTI report for Indian Point 3 notes that their approach to the Plant Life Extension Program is to establish a strong maintenance program. The Nuclear Plant Aging Research or NPAR

Program includes reviews of current maintenance practices and evaluates their effectiveness in mitigating aging. Recommendations for acceptable or preferred maintenance practices and frequencies, and suitable condition monitoring techniques for identifying aging degradation, were developed.

Our goal, therefore, is to determine, by reviewing the MTI reports, if effective preventive maintenance programs have been established and are being effectively implemented. Information from the MTI reports was extracted on the systems, structures, and components that were inspected, the quality and implementation of procedures, and the incorporation of basic requirements from equipment manufacturers, industry groups, technical standards, and regulatory requirements. The information was categorized as follows:

- PM Program
- Implementation of the PM Program
- Frequency of PM
- Engineering and Technical Support
- PM of Mechanical Systems and Components
- PM of Electrical and I&C Systems and Components
- External Technical Requirements

3.2.1 Qualitative Insights

After reviewing the 44 MTI reports, it became evident that every plant has a preventive maintenance (PM) program for its equipment, specifically those that are vital to plant safety and for power generation. The PM program involves scheduled inspections, monitoring of various equipment parameters, parts replacement, and routine maintenance activities, such as repacking, lubricating, and cleaning. The following discussions provide insights into various elements that are necessary for an effective PM program.

PM Program

Several activities cited in the MTI reports suggest that the industry is striving to improve existing PM programs. Most original PM elements are developed in response to regulatory requirements, vendor recommendations, and good practices. A Configuration Management Information System (CMIS) has been implemented at a few plants for enhancing the PM program. This system is centered upon a computerized data system, which includes:

- equipment database
- maintenance records
- modification (design) records
- historical information
- schedule information
- document control logs
- procurement records
- spare part tracking log
- training records and instructions

Other efforts include improvements in the existing PM programs, monitoring of plant performance, predictive maintenance, maintenance trending and analysis, scram frequency analysis, special studies on specific problems, and material condition management programs. Other analytical approaches include time series analysis of equipment failures, improved MOV reliability, and aggressive resolution of problems. Systems, such as auxiliary feedwater, main feedwater and service water, typically are considered for reliability centered maintenance.

Table 3.2 gives some examples of PM tasks for mechanical, electrical, and I&C equipment. Many of these are not focussed to identify age-related deterioration occurring in the equipment. Rather, the PMs are performed to keep the component operable so as not to compromise plant availability.

In addition to these positive aspects, there are citations in the MTI reports which have negative connotations for PM programs. Some PM schedules have not been implemented on a timely basis and in fact, have items long overdue. In some cases, often without adequate justification, certain components, such as molded case circuit breakers and instrument air system filters, were not subjected to PM for long intervals, up to 13 years in one case. Backlogs for PM were high at some plants.

Some non-safety systems and components, although showing severe aging degradation because of their continuously operating status, are not subjected to PM, but are maintained on a corrective basis. Other items not subjected to PM at some plants are: manual valves, MCC circuit breakers, cables, tanks, piping, and pipe supports.

Some plants have used performance indicators to assess PM program activities and/or vital components and systems. Typical indicators used are: the ratio of the number of PM tasks to the total number of maintenance tasks, failure frequency, total downtime, and other reliability parameters.

Table 3.2 **Examples of PM Activities** (Noted in MTI Reports)

Mechanical Maintenance
Installing spring pack in a MOV
Lapping of gate valve seats
Periodically inspecting/replacing dirty filters
Disassembling, repairing and reassembling main steam isolation valves (MSIVs)
Inspecting and eddy current testing of heat exchangers
Snubber Testing
Rebuilding Target Rock relief valve
Repairing motor driven pump (packing leaks)
Changing oil/lubricating, visually inspecting aged parts
Electrical Maintenance
Replacing fuse blocks
Testing and maintaining breakers
Replacing capacitors
Replacing bus bars
Replacing cables
General maintenance of MCCs and relays
Testing ground fault relays
Testing undervoltage relays
Calibrating digital multimeters/calibrators
Checking logic function (channel check)
Testing fast closure response time of MSIVs

Implementation of PM Programs

As the benefits of a good PM program become evident, additional components (such as pumps and valves) are often added to the list for vibration monitoring, oil cleaning, lubricating, cycling, and other activities are performed on components such as breakers and relays. Heat exchangers are analyzed for performance. Erosion/corrosion of pipes, setting torque switches, and computerized scheduling of PM activities are other examples of better implementation of PM programs.

Administrative controls are added to enhance certain PM schedules. More fuses are replaced routinely to avoid blown fuses. Air, water, steam, and oil leaks are routinely checked at a large variety of equipment. Valve failures to open or close are checked.

Table 3.3 PM Frequency for Certain Equipment (as identified in the MTI Reports)

Mechanical		Electrical and I&C	
Explosive Valves	2-5 years	6.9 KV breaker	2 years
Pump Inspection	5 years	Batteries	Weekly
Pump Seals	Every 2nd refueling	MCCs	safety - 5 yrs. non-safety - 10 yrs.
Check Valves	One valve each outage (per system)	Reactor Trip Breakers	18 months
Safety Relief Valves	3 years	<u>I&C</u>	
ISI/IST Valves	Quarterly	Switches & Microswitches	5 years
Governor Overspeed	Annually	Transmitters	5 years
Containment Hydrogen Concentration Monitor Gasket/Diaphragm Change	5 years	Containment Radiation Monitors Changeout of Capacitors Recalibration	 2 years 5 years
EDG	2 yr PM/5yr Insp		
Snubbers Inspection	Each Outage		
Chillers Inspection	5 year		

Areas for improving the implementation of PM include communication between the management, maintenance staff and related departments, engineering support, support interface, post-maintenance testing, procurement adequacy, and use of advanced methods (i.e., reliability, trending).

PM Frequency

Performing PM activities on a timely basis is an important feature of an effective maintenance program. Table 3.3 shows the frequency of some PM activities identified from the MTI reports.

Recent awareness of problems in instrument air systems has prompted many utilities to blowdown the instrument air system biweekly. Certain plants have their component cooling water heat exchangers fouled with biological organisms and need frequent cleaning. At one utility, PM practices are reviewed every four years and the activities are compared to industry practices every two years.

Engineering and Technical Support

The relationship among the engineering and technical support groups, the maintenance staff, and the operations staff at the plant is vital for a good PM program. Because most of the PM activities are based on codes and standards developed by professional societies such as the American Society of Mechanical Engineers (ASME), the Institute of Electrical and Electronics Engineers, Inc. (IEEE), and the Instrument Society of America (ISA), the technical support groups which are responsible for satisfying standards requirements should develop the PM procedures and requirements. Unnecessary failures can be avoided if the technical staff specifies the post-maintenance testing requirements which must be performed prior to turnover of the component to the operations staff. Also, procedures sometimes do not exist or are poor for specific equipment, because of the lack of communication between the staff of the various disciplines.

PM for Mechanical Systems and Components

Most mechanical systems and components with PM programs include all safety-related and important balance of plant systems, and associated pumps, valves, heat exchangers, piping and pipe supports, tanks, and other mechanical equipment. The ASME Code Section XI[14] inservice inspection/inservice testing (ISI/IST) requirements are routinely performed on pumps and valves as part of the plant surveillance (or technical specification) test program. Other formal testing programs include snubber surveillance.

In some cases, non-safety systems and balance of plant (BOP) systems are not part of a formal PM program. Recent problems in IA systems, motor-operated valves, and check valves have prompted the utilities to develop PM programs specific to these systems and components.

Routine PM activities related to mechanical equipment involve cleaning, dusting, periodic inspection, lubricating bearings, changing filters, tightening nuts and bolts, and cycling valves. PM procedures are developed for specific components or a group of similar equipment. Most PM programs are component specific; system level PM programs are considered via reliability centered maintenance (RCM) activities.

PM of Electrical/I&C Systems and Components

Most components cited in the MTI reports include circuit breakers, motor control centers, switches, battery chargers and inverters, and batteries. Only limited maintenance-related information was available on rotating electrical equipment.

The life of circuit breakers has been characterized by the age, rather than the number of cycles they have been operated. Again, several coil burn-outs are due to mechanical binding, but neither the manufacturers nor the utilities have identified any specific PM activities to monitor or address this binding problem other than lubrication.[15] However, contact surface pitting, and erosion of surfaces and arc chutes are part of breaker PM programs. Some battery chargers and inverter PM include cable insulation problems (made out of rubber) and burn out of diodes. Deposits have formed on moving elements of switches. Capacitors have been replaced at the end of their life. Fuses and fuse holders have been noted for corrosion, and these devices are replaced regularly as part of the PM program.

External Technical Requirements

As operating experience accumulates, important information regarding failure modes and material selection becomes available. Sometimes this information is promulgated by utilities via 10 CFR Part 21 reports by vendors, NRC Bulletins, Information Notices, Generic Letters, or professional society guides and standards, and other papers and reports by the industry and researchers. The Nuclear Plant Reliability Data System (NPRDS) database administered by the Institute of Nuclear Plant Operations (INPO) is another source of information that is beneficial to a good PM program. A PM program needs to be flexible enough to consider this information and make necessary modifications.

3.2.2 Conclusions Concerning Preventive Maintenance

The following observations and conclusions arise from the plant-specific insights in Appendix D, Section D.2. In particular, aging degradation can only be effectively managed if the basic preventive and corrective maintenance programs are suitably designed and implemented. As noted from the previous section, all utilities had maintenance programs, many of which are well-designed with noteworthy practices. Most areas for improvement that were noted were in implementing the programs. Not completing activities on schedule and not following procedures were two examples of areas for improvement.

Lack of engineering technical support exemplified itself in inadequate or no engineering reviews of procedures and vendor manuals, and inadequate review of nonconformances and root cause analysis.

The scope of PM programs was generally good for mechanical and electrical equipment, although the coverage of the balance of plant equipment was not consistent. Most noteworthy were the MOV programs, which were comprehensive, and made use of automated monitoring techniques, such as the MOVATS or VOTES systems.

Another recurring area for improvement was the poor control of vendor manuals, and not completely incorporating vendor requirements in procedures.

Many utilities had good overall programs with specific strengths and areas noted for improvement. Some of the noteworthy practices were: reviewing procedures for adequacy on a two-year average frequency, incorporating EQ requirements directly in maintenance procedures, starting reliability-centered maintenance programs (such as at D.C. Cook and Hope Creek) along with computerized main-terminal data bases. Many utilities have achieved a good balance of PM to overall maintenance (i.e., 50%). Two plants (Clinton and Perry) have 13 week "rolling" maintenance schedules where single safety divisions are removed one at a time for maintenance. This concept is a good example of risk-based configuration management.

3.3 Predictive Maintenance and Condition Monitoring Insights

Predictive maintenance and condition monitoring include diagnostic practices which can be useful to predict the remaining life, assuring the operational readiness until the next scheduled maintenance, and to detect incipient degradation due to aging effects. Reliability modeling, trending the degradation rate, monitoring the useful life of certain devices, and estimating the failure rate with age are some of the practices that can predict component life. The most common practices for condition monitoring are thermography, vibration monitoring, lube oil analysis, the current signature of motor-operated valves or measurement of valve stem yoke strain, and check valve inspection and testing. Strictly speaking, predictive maintenance is the term that should be applied to the diagnostic practices, while condition monitoring is the trending of the results obtained from those diagnostic practices, i.e. the condition indicators. Inservice inspection (ISI) and inservice testing (IST) are both forms of predictive maintenance.

According to Nicholas and Young,[16] vibration analysis is by far the most widely used technology in condition monitoring and predictive analysis programs of utilities possessing nuclear power plants. They noted that a survey by the Nuclear Management and Resources Council (NUMARC) showed that over 99% of nuclear plants had some form of vibration monitoring. Many plants have permanently installed vibration analysis systems for critical components, such as reactor recirculating pumps, main turbine generator systems, and some main feedwater and condensate pumps.

Referring solely to the MTI reports, it is difficult to compare one utility's predictive maintenance program to another's. Many of the programs were in the early stages of implementation; therefore, the NRC inspectors could not report upon several aspects of the condition monitoring techniques.

3.3.1 Qualitative Insights

Both predictive maintenance and condition monitoring are often considered part of the overall plant PM program. To characterize and manage aging in equipment before failure, preventive maintenance activities are absolutely necessary to identify the need for and perform maintenance promptly, so that all degradations are not transformed to failures. Many preventive maintenance activities presently being adapted by utilities are based on the following:

- regulatory requirements
- insurance requirements
- vendor recommendations
- good practices evolved from operating experience
- equipment qualification

In the area of predictive maintenance, there are a limited number of methods that utilities are using within a PM program. This limited number of methods is partly because of a lack of understanding of the aging degradation within components, and partly due to the difficulties with estimating the life of component parts. The qualified life of selected safety-related equipment is based on equipment qualification programs which rely upon testing and/or analysis to estimate the qualified life. This estimation is based on a simulated plant condition and may not have considered all the aging stressors which affect a component's life. Nevertheless, the requirements for monitoring the actual condition of equipment are sometimes determined from the equipment qualification testing. The following section discusses certain techniques that are presently in use in the nuclear industry. Specific examples of findings related to predictive maintenance, which appeared in the MTI reports, are shown in Appendix D, Section D.3.

3.3.1.1 Predictive Maintenance Techniques

To effectively predict the equipment condition, the degradation processes should be understood and characterized. Once the weak links are identified, and the degradation process and its rate are established, one could predict by analysis or intuitive approaches based on operating experience, how the equipment or the system would behave until the next scheduled maintenance. Currently, equipment qualification results, reliability centered maintenance, comparison with other databases, vendor recommendations, advanced monitoring methods, and probabilistic risk assessment (PRA) or statistical methods are being used on a very limited basis. The NPAR program has characterized the aging of several components and these results could be useful for condition monitoring and predicting the useful life of equipment.

Equipment Qualification

For safety-related equipment, the qualified life of the equipment should be established before its operation in nuclear power plants. IEEE-Standards 323[17] and 344[18] have defined the procedure and the acceptance criteria for this qualification process. In this process, the component's life is predicted using the Arrhenius methodology specified in IEEE Standard 323, and often the weak links and their first useful lives are established. For example, a 10-year life for electrolytic capacitors in an I&C circuit has been predicted, and plants replace or refurbish these devices as they approach the end of life. This qualification process identifies the operating life and sometimes includes the shelf-life, if applicable. The qualification tests and the analysis results are compared against the design basis conditions. However, aging stressors might arise during operation that were not considered in the qualification process.

Reliability Centered Maintenance (RCM)

At this time, plants have used RCM at the system level, rather than component level, to prioritize the maintenance schedules. In applying RCM, a very detailed failure mode and effect analysis is generated which identifies the important critical components and establishes the overall system reliability. If properly implemented, RCM can provide assurance of the component's reliability between maintenance activities.

Comparison with NPRDS or Other Plant Records

Trends of component or system failures are determined using either individual plant maintenance records or national databases which contain several different plants' records on the subject. Many times, these trends have not only identified the weak links, aging mechanisms, or failure frequencies but also have provided some basis to predict the expected life of a component/system. Comparing these findings with a plant's own equipment history can help to predict the useful life and identify appropriate maintenance activities.

Vendor Recommendations

In addition to the recommendations given in the equipment brochures and maintenance manuals, the equipment qualification documentation on findings are often used as manufacturer's recommendations. One way of estimating the useful life of equipment is to perform appropriate testing, such as life testing, and analysis, such as Arrhenius, simulating the true plant conditions. This process of testing and analysis is very expensive and the manufacturers typically do not make the results available to the utilities because of their proprietary nature.

Advanced Monitoring Methods

Monitoring or trending of certain on-line parameters (such as vibration level, flow rate, leakage rate, dielectric strength, wear, corrosion) can indicate the condition of equipment. The remaining life of the component or system can be predicted by comparing the parameters against the acceptable level (or allowable limit). However, establishing the acceptance level is one of the most difficult tasks, because the level must be sufficient to assure the operational readiness of the equipment. Most plants do use various monitoring methods to periodically check the condition of the equipment, but such information is still not used extensively to predict remaining life.

PRA or Statistical Approach

Some plants use PRA (fault tree/event tree) or other statistical models to predict the behavior of the component or the system. In the case of PRA, the actual or proposed system unavailability due to maintenance is used to assess a component's relative importance with respect to the core damage frequency or risk of offsite consequences. Downtime of the component, corrective maintenance frequency, or trending of certain operating parameters are used in the model to predict a component's failure rate and its effect on system reliability, plant outage time, core damage frequency and risk of offsite consequences.

3.3.1.2 Condition Monitoring Techniques

Some of the more common techniques identified in the MTI reports are the following:

Vibration Monitoring

The ASME Code Section XI requires quarterly vibration monitoring of safety-related pumps. Vibration monitoring and trending techniques, broader in scope than required by the code, are commonly used on continuously operated safety-related equipment such as charging pumps and motors of Component Cooling Water (CCW) and Chemical and Volume Control Systems (CVCS). These techniques also are used at some plants for BOP equipment, such as main station turbines, main feed pumps and turbines, circulating water and condensate pumps, and cooling water pumps for generator stators. Some plants monitor standby safety-related systems such as the pumps and steam turbines for the auxiliary feedwater (AFW).

Lubricating Oil Analysis

Lubricating oil typically is analyzed for some safety-related equipment, such as emergency diesel generators (crankcase oil) and reactor coolant and charging pumps and motors of the CVCS. Some plants include pumps and motors for auxiliary feedwater (AFW), low pressure and high pressure safety injection (LPSI and HPSI) and containment spray in the analysis program. BOP components, such as the condenser vacuum system also may be included. The lube oil analysis is intended to assure proper viscosity, acid/base (pH) value, water content, and level of solid particulates. Changes in such properties could indicate frictional wear and undesirable contact with a rotating surface, or heat exchanger leakage.

Thermography

Thermography is performed by using heat-sensitive infra-red light to form a thermal profile image of the object being inspected. Abnormal heat generation is usually a sign of excessive friction or undesirable electrical contact resistance, or overcurrent conditions. This method can detect looseness of electrical connections and the deterioration of electrical insulation and printed circuit boards. One utility identified the following components as subject to thermography:

- Generator current transformers
- Exciter switchgear
- Motor control centers
- Station service transformers
- 6.9 and 4.16 kV breakers
- 480 V breakers
- Motor-generator sets
- Rod control cabinets
- Reactor trip breakers
- DC distribution panels
- Electrical penetrations
- Instrument air compressors

Testing of Motor-Operated Valves

In response to NRC Bulletin 85-03,[19] its Supplement No. 1,[20] and NRC Generic Letter 89-10,[21-24] utilities implemented methods to record and trend changes in the motor signature current of a motor-operated valve. One such method is referred to by the tradename MOVATS (Motor Operated Valve Analysis and Test System), which was heavily used in testing Limitorque valve operators, the subject of the NRC Bulletin.

Another way to measure MOV operability is to measure yoke strain, which is an indicator of stem thrust. Measurement of yoke strain provides information for both the open and closed direction through the entire stroke. Some utilities are also implementing such a procedure, known by the tradename VOTES (Valve Operation Test Evaluation System).

As of mid-1991, the NRC sponsored testing of six vendors' methods for measuring operability of MOVS. Preliminary results indicated substantial differences in the accuracy of measurement methods, with VOTES tentatively appearing to give the more accurate measurements.[25] From the MTI reports, we noted that at least one utility was using both MOVATS and VOTES for comparison purposes.

Miscellaneous

Some other methods of condition monitoring or predictive maintenance which were cited in the MTI reports, were the following:

- Implementing an MOV overhaul and diagnostic program, which includes a complete inspection and lubrication of the main gear case, limit switch compartment and valve stem, and proper setting of torque and limit switches.

- Measuring MOV stroke times (ASME Section XI requirement).

- Taking color photographs of internals of MOV operators to show the number of limit switch rotors, whether an approved torque switch was installed, and whether there was the correct number of jumper wires.

- Disassembling and inspecting check valves (Generic Letter 89-04).[26,27]
- Ultrasonically testing for leakage from BOP valves.
- Monitoring pipe wall thickness for erosion and corrosion (Required by Generic Letter 89-08).[28]
- Measuring differential pressure across safety-related pumps, such as containment spray, service water, component cooling water, and auxiliary feedwater (ASME Section XI requirement).
- Performing helium leak detection and eddy current testing of tubes of lube oil heat exchangers.
- Trending terminal temperature differences (TTD) vs. time for feedwater heater, moisture separator reheaters, and main condenser.
- Monitoring exhaust gas of the emergency diesel generators.
- Measuring individual cell voltages of station batteries.
- Overhauling 4160 V metal-clad switchgear, including verifying undervoltage trip attachments, cleaning and inspecting breakers (with breaker removed), cell and relay/control wiring compartments.
- Performing shock pulse analysis.
- Implementing a monitoring program which assesses neutron flux to detect motion or movement of the thermal shield (vessel internals).
- Monitoring for loose parts to detect objects in the reactor coolant system by means of an accelerometer attached to the reactor vessel.
- Implementing Electronic Characterization and Diagnostics (ECAD), a technique in which electrical loop characteristics are measured to anticipate degradation in components or connections.
- Using a Redundant Instrument Monitoring System (RIMS), a technique which compares redundant channels to detect incipient channel calibration drift.

3.3.2 Conclusions for Predictive Maintenance and Condition Monitoring

Use of advanced condition monitoring techniques still was in the early stages of implementation at most plants. However, there was an impressive trend of increasing usage of such techniques.

From the data, a very good example of one utility's initiative appeared to be the micro-electronic surveillance and calibration (MESAC) system, which was designed and developed at the Braidwood station to dynamically test instrument systems. Not only are continuous test signals injected that simulate design basis inputs, but because no lifted leads or jumpers are required, the risk of unplanned reactor trips is significantly reduced.

Also of great interest are the examples of condition monitoring techniques which successfully identified degraded equipment so that it could be replaced on a schedule rather than after an unexpected failure. At least two examples were evident at River Bend: degraded rotating equipment, such as a motor bearing of a circulating water pump, and an alignment problem with a speed increaser of a main feedwater pump. A dissolved gas analysis of transformer insulating oil showed a high level of acetylene, a sign of electrical arcing within the transformer. This finding enabled replacement of the transformer during an outage.

Similarly, at St. Lucie, vibration analysis of the Main Feedwater pumps produced results which alerted the utility to implement repairs during power operation, so that a reactor trip and the consequent challenge to safety systems were averted.

Other noteworthy techniques are acoustic monitoring of check valves, monitoring of lubricating oil in both electrical and mechanical rotating components, such as pumps and motors, and infrared thermographic imaging of electrical and mechanical components.

For the areas noted for improvement, several examples of utilities not performing the condition monitoring techniques recommended by vendors, i.e., surveillance techniques, were evident. Violations cited by the NRC against some plants involved failures to test similar safety-related 4 kV breakers in response to observed failures of others to operate during surveillance testing, as well as a failure to test the overspeed mechanism of the turbine-driven Auxiliary Feedwater pump for 17 years since installation.

Examples of potential deviations from the testing and acceptance criteria of the ASME Boiler and Pressure Vessel Code, Section XI, also were noted, including testing of High Pressure Safety Injection pumps at a few plants. Inadequate testing of MOVs in response to NRC Bulletin 85-03 and Generic Letter 89-10 also was observed.

3.4 Post Maintenance Testing

Another important aspect of the Maintenance Team Inspections was post maintenance testing (PMT). U.S. NRC Regulatory Guide 1.33, on quality assurance program requirements for reactor operations, issued in 1978, endorses ANSI/ANS 3.2, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants",[29] which requires that tests be performed following plant maintenance to confirm that the maintenance produces expected results and does not reduce the safety of operations. ANS-3.2 was updated in 1982.[30] The ASME Boiler & Pressure Vessel Code, Section XI, Subsections IWP and IWV,[14] which pertain to pumps and valves, specifically address the requirements for testing following any maintenance that would affect component performance.

In the NRC Maintenance Inspection Guide, Volumes 1 and 2,[31,32] which provided guidance for the MTIs, the inspectors were asked to determine whether PMT criteria have been established, documented, and implemented. The inspectors also were asked to identify criteria which define operational readiness, specify when PMT is required, and define acceptance.

3.4.1 Qualitative Insights

Post maintenance testing, as the name implies, is an activity or several activities that assure the operational readiness of a component or a system after maintenance (PM or CM) was performed to monitor age-related degradation or to restore it to its normal operating condition. Depending on the complexity of the component or the system, these requirements sometimes can be quite involved and require multi-disciplinary support. For simple replacement of parts, such as changing pump filters, seals or covers, the PMT requirement can be just checking the Δp across the filter, inspecting the leakage of seals or checking the mounting conditions of covers.

PMT also is referred to as operations verification testing, functional testing, channel checking, or time-delay testing, depending on the application to a particular component or a system. PMT may include surveillance testing, inspection, checking, or just operating the equipment. In some cases, although these activities are very well documented and comprehensive in scope, acceptance criteria to confirm the operational readiness are very limited and vague. One of the most difficult aspects of PMT is establishing the acceptance criteria. The manufacturers often do not define the thresholds which signify that the degree of degradation is unacceptable.

Most equipment or systems subjected to the PMT include those requiring ASME Section XI testing (i.e., pumps and valves), technical specification testing (i.e., safety equipment, specifically I&C), and electrical testing (i.e., breakers, motors, inverters, delays). Equipment such as feed pumps, compressors, and main turbine cooling water pumps are not formally subjected to PMT requirements because of their non-safety, balance of plant status. Most plants, for safety-related equipment, use surveillance test methods, including ISI/IST requirements as part of the PMT requirement. Some plants have made improvements on the basis of operational readiness tests or functional test results. In some plants, the PMT requirements were found to be poorly defined, too brief, or the test procedures were confusing. In certain cases no PMT was being performed nor was an adequate explanation given as to why PMT was not performed.

PMT methods dentified in the MTI reports include:

- protective trip testing of molded case circuit breakers,
- colored photography of equipment,
- analysis or test of the maintenance performed,
- equipment running or cycling,
- Electrical Characterization Analysis & Diagnosis (ECAD),
- analysis versus NPRDS information.

- Redundant Instrument Monitoring System (RIMS) for calibration,
- MOVATS/VOTES on MOVs, and
- reading proper instrumentation after starting the equipment.

Human-related problems have been discovered during PMT and actions must be taken to restore condition of the equipment. Sometimes the PMT activity itself caused a need for corrective maintenance. In general, the plant system engineers are not involved in assessing the PMT requirements to the degree that they should be involved.

Because the objective of PMT is to assure the proper condition of equipment or system after maintenance, it does not directly affect aging assessment. It is assumed that aging degradation has been mitigated by the maintenance itself. However, if the PMT does not identify ineffective maintenance, then aging can occur. In fact, improper maintenance can accelerate aging. Therefore, proper PMT requirements are necessary to properly manage aging.

Based on the MTI reports reviewed, an effective PMT program can be developed if the following factors are taken into account:

- the involvement of system engineers
- the scope of the completed maintenance
- applicable standards and codes
- plant technical specifications
- vendor recommendations
- acceptance criteria
- comprehensive checklist for mechanical and electrical conditions
- a well-documented maintenance procedure (step-by-step)
- satisfactory documentation

Some plants have benefitted from a good PMT program. The effectiveness of the maintenance activity is measured by the success of the PMT. Examples of some utilities' experience with PMT requirements are summarized below. Specific examples from the MTI reports are provided in Appendix D, Section D.4.

3.4.2 Conclusions on Post Maintenance Testing

At some plants, the NRC noted that the utilities relied upon the surveillance tests and calibration intervals required by Technical Specifications to satisfy PMT requirements, particularly for I&C components. For such components, the NRC usually considered this testing to be acceptable, but for relatively complex mechanical and electrical components, such as pumps and circuit breakers, the NRC often concluded that such testing is generally an operational test, rather than a specific test which focused on the actual maintenance work performed. As a specific example, the PMT program at Surry was noted as being very limited for equipment other than that covered by the ASME Code, Section XI, such as electrical components. The NRC noted, however, that most I&C and electrical procedures have sufficient testing and calibration requirements that are equivalent to PMT.

Another common problem cited in the MTI reports was a lack of specific PMT requirements. The requirements were often vague and very general, with statements such as "test run and check for seal leakage" and "run a sufficient amount of time to determine if it performs its intended function" cited for pumps and compressors. Documentation of PMT results also was frequently considered poor.

At least two examples of PMT-related violations were noted in the reports. At Fermi, operations personnel accepted an RHR check valve without a stroke test following maintenance. The valve did not stroke, was incorrectly reassembled, and inadequate instructions were provided. At Palisades, required flow and differential pressure readings were not taken before performing maintenance on a Component Cooling Water heat exchanger.

While examples of well-documented and implemented PMT programs were cited in the reports, we concluded that PMT was an area that required improvement at many plants.

3.5 Failure Trending Analysis

One of the methods for managing the aging of critical components and systems is to monitor their performance by evaluating the statistical pattern of performance indicators or component failures over a period of time. These performance indicators can be derived from records of certain plant activities, such as deficiency reports, maintenance and test evaluation reports, total job management records, maintenance work requests, and component/system functional parameters. If sufficient statistical data are available, then surveillance, preventive maintenance, or replacement can be sched-

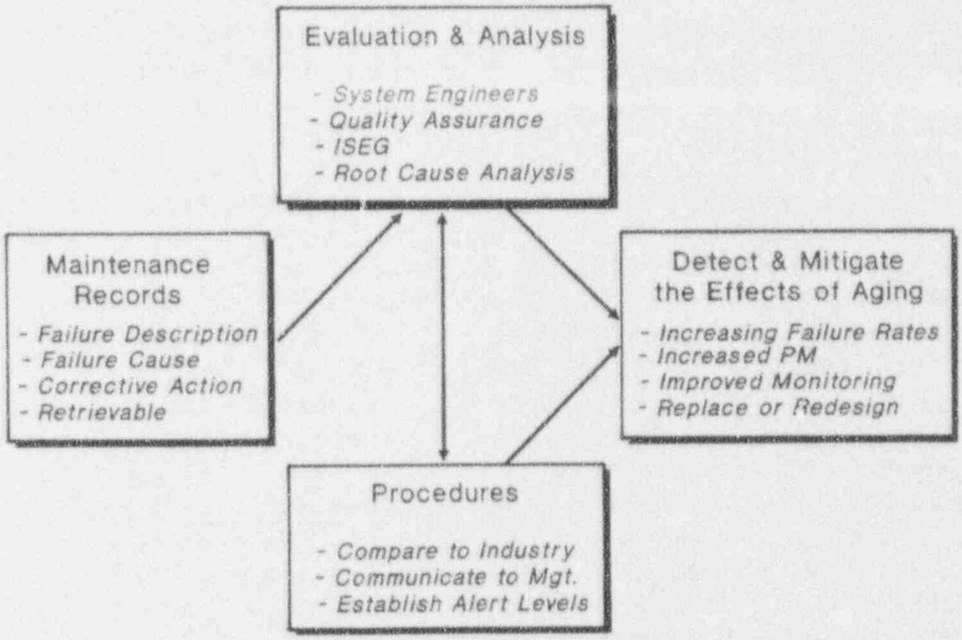


Figure 3.1. Trending program for managing aging

uled more effectively on the basis of performance or functional indicators and failure trends.

To effectively manage aging, one must be aware of the changes in components or systems which could indicate impending failure. In addition, it is imperative that maintenance records be complete, equipment degradation and failures be conscientiously evaluated, and procedures be followed to ensure that a coordinated program is implemented. As illustrated in Figure 3.1, detecting the effects of aging (increased failures with time) using a trending program requires that an integrated approach be used, which involves the mechanics and electricians who fill out the maintenance work orders, the technical support groups who evaluate the failures, and plant management, which authorizes changes in the maintenance program or approve design changes. The MTI reports provide insights into these various areas which are summarized in this section. Specific examples from the MTI reports are provided in Appendix D, Section D.5.

The MTIs acknowledged the importance of trending in a nuclear power plant's maintenance program as shown by the many inspection areas which addressed trending. In addition to Section 6.4 of the Maintenance Inspection Tree (Figure 2.1), which is entirely devoted to trending, other inspection areas also assessed the plant's trending programs. For example, in Section 3.5, "Conduct Performance Measurement," the NRC inspectors determined whether the utility established and implemented maintenance performance indicators. Similarly, in the important area of technical support, the reports give an evaluation of Quality Control and the utility's program for trending quality deficiencies to establish that programmatic deficiencies have not developed. In Section 5.3, the inspection of work orders is the means to determine if historical records are used to establish trending for maintenance purposes, and if the trending process identifies the component, system, cause of defect, and corrective action.

In Section 6.4 of the MTI Guidance, the inspector is asked to "determine, by sampling the method of work generation, inspecting selected repeat failures, and reviewing present and past equipment records," whether the following exist:

a. Has the maintenance organization established a maintenance trending program?

b. Are written procedures for the maintenance trending program in effect and documented on the system, component, and part level?

c. Does the maintenance trending program address systematic fixes versus specific fixes, root cause analysis, performance indicators, and rework evaluation?

The answers to these questions in the MTI reports were evaluated to determine if the trending in the present maintenance programs is adequate to manage aging.

3.5.1 Qualitative Insights

The MTI reports describe trending in programmatic terms and for specific equipment and systems. Assessments of the adequacy of implementing the program at the various levels of the utility's hierarchy, including corporate and plant management, QA, the maintenance department, and the support organizations which perform functions related to maintenance work controls and documentation are given.

Several similar findings pervade the MTI reports, which indicate that many plants are effectively using trending techniques to improve maintenance effectiveness. The reports showed that nine plants used industry data well; eight plants had advanced computerized programs with enhanced trending capabilities; and five plants had maintenance programs which identified the importance of trending. Other positive findings were in the areas of technical support (QA and System Engineers), procedures, communications, and recordkeeping.

However, we identified several common areas for improvement, which shows that maintenance trending programs are not adequate for detecting and mitigating aging. The NRC findings emphasized inadequacies in the maintenance records. To a lesser extent, technical support, procedures, and general inadequacies in the program were also discussed. In the following sections, we discuss the positive findings and areas noted for improvement in the trending programs that we deemed to be most significant for managing the effects of aging.

3.5.1.1 Maintenance Records

When performing maintenance, it is essential that information relevant to the status and condition of the equipment be recorded, evaluated, and preserved, including:

- as-found and as-left conditions,
- specifications for replacement parts,
- key measurements, readings, and tests, and
- cause, mechanism, and description of failure.

It was common to find criticism of the maintenance records, particularly of corrective maintenance work orders. In fact, of the 44 MTI reports reviewed, 16 contained negative findings. For the most part, the inadequacy of the records affected the ability of the plant personnel to detect existing trends. There are seven instances where as-found conditions were not recorded; three where the description or cause of failure was not identified; and several where the NRC inspectors made a general statement about the inadequacy of the records and its detrimental impact on the ability to trend. The following are specific noteworthy findings:

1. At Ginna, of 100 work orders reviewed, only 8 contained as-found conditions that could be useful for trending.

2. At H.B. Robinson, the maintenance work packages contained insufficient information to trend degradation or failures.

3. At ANO, because of the lack of descriptions of component failure, trending of the maintenance data could not identify common mode failures due to aging, improper maintenance, or material defects.

There were only three positive findings on the adequacy of documentation of completed maintenance work packages: at Braidwood, which simply stated that corrective maintenance was documented to identify trends; at Indian Point 2, which stated that documentation of I&C maintenance was very complete; and at Perry, where the summaries of work performed were detailed so that the root cause could be determined.

In general, newer plants, i.e. plants which went on-line in the 1980's, have an easier task to implement a trending program because they have the benefit of recognizing the value of failure trending and collecting data in a trendable form early in plant life. Many of the older plants, i.e. plants which went on-line in the 1960's and 1970's, simply are forced to ignore their maintenance records before the mid-1980s because of their lack of detail and usefulness for failure trending. Records before that time were usually maintained manually; thus, retrieving records of component history for trending is cumbersome.

To properly manage aging, equipment and system performance must be evaluated over several years. Without adequate records, this task is impossible. The MTI reports show that significant improvement is required to satisfactorily address plant aging.

3.5.1.2 Comparison of Plant Performance to Industry Data

One method of determining the adequacy of a maintenance program is to compare the performance (failure rates) of an individual plant's equipment and systems with industry-wide averages. As part of the Maintenance Inspection, the NRC determined whether industry-wide data were used by the utilities to alert them to potential problems. This is an important area of managing aging because a larger database, including input from older plants, depicts more completely whether or not aging is an important failure mechanism for the particular equipment.

Of the 11 MTI reports which evaluated this area, 9 had positive comments. In the 2 following cases, the inspection team was not satisfied with the utility's use of industry data:

1. At Duane Arnold, the system's performance for negative trends was not evaluated as required by the station's procedures. NPRDS and LERs were not reviewed by the system engineers. The plant's response to an upgrade for safety-related circuit breakers was not timely, considering the general trend of high failure rates on that equipment.

2. At Maine Yankee, the trending and evaluation system was functioning, but it did not use NPRDS.

Of the positive findings NRC inspectors noted that INPO performance indicators (PIs) were used as well as the component failure analysis report (CFAR) available from NPRDS. A quarterly review cycle was typical. A CFAR can be a useful tool for detecting aging trends. The standard CFAR contains comparisons of the plant specific failure rates to industry-wide averages, and identifies those components with significantly higher failure rates (>1.645 standard deviations above industry average); this information provides an alert level which triggers further engineering analysis.

One topic of discussion in several of the MTI reports related to data trend evaluation was the threshold established by the utilities for taking action. The general conclusion by NRC at several plants including Zion, Dresden, and H.B. Robinson, was that it was inadequate for a trend program to use a failure rate of two or three events per year, as tracked by the unique component identification number. The NRC noted that the method does not account for recurring failures to certain models or types of equipment. These common mode failures could be overlooked if only the equipment identification number is used.

3.5.1.3 Technical Support

At several plants, the task of reviewing data and failure events is assigned to a technical support group outside of the Maintenance Section. The MTI reports describe several variations on how this review is accomplished, including the use of system engineers, an independent safety evaluation group (ISEG), or the quality assurance (QA) organization. In all cases, the NRC inspection team evaluated the ability of these support organizations to perform trending, root cause analysis, and other functions relevant to managing aging.

Positive statements were made in 12 of the MTI reports, whereas 6 described weaknesses in this area. From the aging perspective, a positive attribute is that the system engineer is aware of the failure reports generated on that system, and can accurately assess these events over time. At four plants, the QA section performed trending of failures on various components, largely from a statistical point of view, that is, a detailed engineering review of the failures was not necessarily achieved or expected. Similarly, the MTI reports identified three plants with effective trending programs conducted by an ISEG.

The NRC inspection team noted the following:

1. At Duane Arnold, the evaluation of system performance for negative trends was not conducted by the system engineer, as required by station procedures.

2. At LaSalle, the system engineers were not involved with routine maintenance, and therefore, may not detect subtle trends.

Technical support groups need to be involved with the maintenance organization to monitor trends, to evaluate the potential for common cause failures, and to assist in formulating long-term corrective action.

3.5.1.4 Programs/Procedures

There were positive findings in the MTI reports about computer-based programs that enhanced trending capabilities. Several specific programs were discussed:

CHAMPS - Computerized History and Maintenance Planning System, which is used to trend equipment failures at four plants. Monthly reports are issued identifying the components with recurring problems.

SIMS - Station Information Management System, which provides very detailed information needed for trending.

PADS - Problem Analysis Data System, which is used at Zion to flag components with repeat failures or rework.

DORIS - Daily On-Line Retrieval System, which is used at Indian Point 2 to trend maintenance. In addition, other trending programs which the NRC inspectors found to be positive aspects of the Maintenance Program included:

1. At Braidwood, a newer PWR, an "innovative trending program", which tracks audit and surveillance findings, weighs their significance, and expresses them as an equation to determine weak areas.

2. At Vermont Yankee, an older BWR, the NRC inspectors discussed "a well-conceived" trending program, which identifies the need for increased maintenance, common mode failure analysis, and changes in equipment failure rates.

The procedures, which need to be in place within the maintenance program, were only discussed briefly in terms of trending. To manage aging, procedures are an important means to ensure that a consistent approach is taken to aging-related problems which will occur throughout the life of the plant. The MTI reports identified three plants with procedures for trending, and six without adequate procedures.

3.5.1.5 Specific Equipment/System Trends

Table 3.4 summarizes the specific equipment and systems which utilities were monitoring for trends indicative of degradation. These are examples only and do not imply that this is the only trending performed.

3.5.2 Comparison to NRC Findings

It is very useful to compare these findings to the NRC's findings, presented by Gody et al.[5] on failure trending. Of the 31 sites evaluated by the NRC through Fiscal Year 1989, nearly 25% were rated as poor in maintenance trending, and 29% were rated as poor in the area of technical and engineering support. The NRC noted the following:

- Repetitive failures of equipment were not identified as a basis for changes in the scope of the preventive maintenance program.

- Reports typically indicated gross overall trends and did not identify repetitive failures over a long period, subtle trends, or component failure trends.

- Documented information on completed work packages was not adequate to assist in root cause analysis or in analyses of future trends.

- Some programs were fragmented so that a single reviewer did not see all the information.

3.5.3 Conclusions for Failure Trending

To successfully manage aging, detecting equipment degradation or increasing failure rates is essential. One tool available for detection is trend analysis. The evaluation of the MTI reports revealed that most plants are deficient in failure trending. In general, newer plants have an easier task to implement a trending program, because they have the benefit of starting to collect data in a trendable form early in plant life. While it is difficult to assess the safety significance of some areas noted for improvement, it is clear that at many plants, a lack of commitment to monitor long-term degradation and failure histories of key components, systems, and structures makes it unlikely that the maintenance program will be effective in detecting and mitigating the effects of aging.

3.6 Root Cause Analysis

Root cause analysis (RCA) is an important programmatic technique to prevent or minimize repetitive component failures, and consequently, reduce maintenance backlogs and outage time. RCA also is important for identifying and correcting age-related degradation.

Table 3.4 Examples of Positive Findings Concerning Failure Trending

A. Component/System	Number of Plants (Names)
Heat Exchangers	2 (Indian Point 3, McGuire)
Circuit Breakers	1 (Waterford)
Instrumentation & Controls	5 (Duane Arnold, Limerick, Dresden, Hope Creek, Perry)
Emergency Diesel Generators	3 (Hope Creek, Grand Gulf, McGuire)
Piping	1 (Yankee Rowe)
Electrical Equipment	2 (Grand Gulf, Yankee Rowe)
Valves	5 (Indian Point 2, Clinton, Fitzpatrick, Fermi, South Texas)
B. Parameters Trended	
Oil Analysis	4 (Riverbend, LaSalle, Fitzpatrick, Dresden)
Vibration	4 (St. Lucie, LaSalle, Fitzpatrick, Dresden)
IST Data	3 (Indian Point 2, Prairie Island, Cooper)

According to the EPRI definitions,[11] the failure cause is the circumstance during design, manufacture, installation, use, or maintenance which has led to failure. The circumstance can be a physical process, event or condition. Examples of failure causes are an improperly configured moving part (design or manufacture), a material defect (manufacture), aging or service wear, or operation outside the design envelope (use). There can be more than one failure cause.

The root cause is the fundamental failure cause for an observed condition which, when corrected, prevents its recurrence. The observed condition can be a degraded state, a malfunction, or a breakdown. There are four general types of causal factors or events:

1. Hardware (failures of systems, structures, or components due to inherent causes).

2. Human (errors in design, fabrication, installation, operation, testing, and maintenance).

3. Environmental (internal plant stressors applied to the component).

4. External (events external to the plant that result in greater than normal environmental stress).

Often, the root cause is a combination or two or more causal factors that synergistically produce a condition. Failure analysis is conducted after a failure has occurred, to understand the mode, the mechanism, all contributing failure causes, and the likely root cause.

3.6.1 Techniques of Root Cause Analysis

There are several methods by which RCA is implemented, among which are the Management Oversight and Risk-Tree Analysis (MORT)[33], causal factors analysis, change analysis, barrier analysis, fault-tree analysis, and the human performance evaluation system. Some of the methods, as given by Ferry,[34] are:

3.6.1.1 Management Oversight and Risk-Tree (MORT) Analysis

Within the MORT system, mishap means an unwanted transfer of energy that produces injury to persons, damage to property, degradation of an ongoing process, and other losses. A mishap occurs because of inadequate energy barriers and/or controls. The event follows sequences of planning errors that produce failures to adjust to changes in human or environmental factors. The general forms of damaging energy are kinetic, thermal, electric, chemical, acoustic, biological, and radiation.

The MORT diagram is a logic tree with a mishap as the first and top event and three main headings or branches. The MORT diagram symbols are similar to those used in fault tree analysis, but not identical. The three branches are the following:

- S Factors - specific oversights and omissions associated with the mishap.

- R Factors - assumed risks which are known but uncontrolled, e.g. an earthquake.

- M Factors - general characteristics of the management system that contribute to the mishap.

3.6.1.2 Causal Factors Analysis

The charting sequence of the events and causal factors is an integral tool in the MORT analysis and graphically depicts the entire mishap by showing the relationship of individual events in sequence and the related causal factors and conditions impinging on these events.

3.6.1.3 Change Analysis

Change is both directional and exponential. Directional means that change continues in the same direction unless there is another change. Exponential means that changes interact to compound the effects on mishaps. For example, drivers who increase normal driving speed to 70 miles per hour in a 55 mile per hour zone will probably maintain that speed as long as they can get away with it (directional). Furthermore, other drivers will increase their speed to 70 miles per hour because they see the other drivers getting away with it (exponential).

The basic change analysis process was developed by Kepner and Tregoe and involves six steps:

a) Look at the mishap situation.
b) Consider a similar, but mishap-free situation.
c) Compare the two situations.
d) Describe all the differences between the situations.
e) Analyze the differences for effect on producing the mishap.
f) Integrate the differences into mishap causal factors.

Changes can be categorized into eight areas:

- Planned versus unplanned changes.
- Actual versus potential or possible changes.
- Changes with time.
- Technological changes.
- Personal changes.
- Sociological changes.
- Organizational changes.
- Operational changes.

3.6.1.4 Fault Tree Analysis

The fault-tree analysis is the technique used most widely for system safety. An undesired event (a failure) is selected and all the possible occurrences that can contribute to the event are diagrammed as a tree. Beginning with an undesired event (mishap or failure), called the top event, the fault tree analysis reasons backward, tracking events that could have led to the unwanted occurrence. A schematic of the system is used to trace the contributory events.

Barrier analysis is a method which is particularly useful in investigating events related to repetitive breakdowns of established programs.[33]

3.6.2 Qualitative Insights

With respect to the techniques applied at nuclear power plants, root cause analysis, sometimes identified as root cause evaluation (RCE) or component failure evaluation (CFE), is an in-depth analysis of a system or component failure event occurring in a plant. Sometimes, the CFE is a limited evaluation of RCE and as a result, while systems or components important to safety are subjected to detailed root cause analysis, other BOP or nonsafety-systems are assessed by the CFE. In other cases equipment qualification (EQ) documents are the only vehicle for performing this evaluation.

Two specific approaches are described in the MTI reports; namely, system level and component/equipment level root cause analysis. Root cause analysis on a system level uses the term reliability centered maintenance (RCM), in which a detailed failure mode and effect analysis (FMEA) is performed on each system to understand and characterize the aging within a system. Safety-related systems and power generation systems have been focussed on by the industry at this time.

The second approach is at the component or equipment level, where the equipment failure is scrutinized for the root cause which led to its failure. This can be a life-limiting component or device, an aging mechanism affecting several subcomponents, or an administrative procedure contributing to the occurrence, or a design/material selection of the equipment itself. Techniques typically used by the utilities to gather data for root cause analysis include inspecting, testing and monitoring equipment. Inspections are not highly structured nor formally written as procedures, while testing and monitoring techniques are limited to vibration analysis, chemical analysis of oil samples, thermography, surveillance of MOVs using MOVATS or VOTES, and analysis of infrared temperature profiles.

Seal leakage, stress corrosion cracking by chlorides, shaft wear, and oversizing or undersizing of the equipment are some examples of the root causes of mechanical equipment failures. Electrical equipment often displayed problems attributed to jamming of mechanical parts, contact problems, and cracking of battery cells leading to leakage of battery fluid. Similarly, I&C components exhibit set point drift, contact burn-out, and the end of life of certain life-limiting devices. Table 3.5 shows some examples of systems and components that the utilities have subjected to RCA.

Elements that are required to develop a good RCA program, as shown in the MTI reports, are the following:

- management support with resource allocation,
- dedicated staff, including system engineers,
- trained personnel (including formal training programs),
- procedures delineating a structured approach, and
- data management for proper retrieval capability.

A good RCA program will provide several advantages to the utilities for managing aging, including component or system reliability, recommendations to prevent recurrence of the same event, identifying common mode failures, predicting the weak links and their service life, historical information on aging issues, eliminating the backlog of maintenance activities, and better administrative control of the aging problems in the plant. It should, however, be noted that the effort to achieve these benefits requires a commitment by the plant management, adequate resources, and dedicated time.

3.6.3 Conclusions on Root Cause Analysis

A summary of the examples relating to RCA cited in the MTI reports is as follows. Appendix D, Section D.6 gives some specific examples:

The NRC cited several examples of excellently performed and documented cases of root cause analysis; for example, at St. Lucie, the modification to battery chargers in which the current limiting resistor was modified, with the vendor's approval, to install two adjustable 500 ohm resistors in series, thereby making it easier to adjust output current and voltage.

The NRC also noted the thorough and exhaustive failure analysis performed at Perry after the failure of some MSIVs to close or remain closed; this analysis included a laboratory analysis of parts from the air packs.

At other plants, such as Prairie Island, the System Engineer concept was well established, and system engineers were involved in the root-cause analysis.

However, there were several instances where utilities failed to perform a timely root-cause analysis, and therefore, failed to take corrective actions. Violations were cited for failing to perform RCA promptly, at Palo Verde and Duane Arnold, for leakage and failures in the thermal overloads of the cooling pump motor, and associated contacts in the emergency diesel generator jacket cooling water system. Root-cause analysis often was not required for balance of plant (BOP) components.

Numerous examples of poor documentation of "As Found" conditions were noted, such as at Hope Creek, where none of 15 work orders reviewed by the NRC had a "cause of failure" or "cause code." This was cited as a violation by the NRC. Other documentation problems cited were excessive use of the term "other," "plant aging," "normal wear," design inadequate," and "personnel error," as a cause of failure.

Other problems in root-cause analysis were exemplified by analyses which were of insufficient depth, or were characterized by the NRC as poor, or where the threshold for performing RCA was too high or ill defined. Procedures on explaining how to perform a root-cause analysis were sometimes inadequately detailed. System engineers were sometimes inadequately trained and not involved in activities such as trending and root-cause analysis.

In summary, while the NRC cited several examples of thorough and detailed analyses and proper recording of failure cues, as with post-maintenance testing and failure trending, we concluded that root-cause analysis was another area that required improvement.

Table 3.5 Some Examples of Components/Systems Considered for RCA Identified in the MTI Reports

Systems		
Service Water		
Reactor Water Cleanup		
Uninterruptible Power Supply		
Components		
Mechanical	**Electrical**	**I&C**
Pumps	Circuit Breakers, Diesel Generators	Switches-/microswitches
Valves	Relays	Analog Circuits
Snubbers	Batteries	Transmitters
Heat Exchangers	Transformers	

3.6.4 Comparison to NRC Findings

While the attributes and deficiencies described in the previous section are not all inclusive, it is useful to compare the deficiencies to the NRC's findings cited by Gody et al.[5] Specifically, for the plants which were cited as having poor technical and engineering support of maintenance and also poor maintenance trending, the following reasons related to root-cause analysis were noted:

- Repetitive failures of equipment were not identified as a basis for changes in the scope of the preventive maintenance program.
- Inadequate root cause analyses were performed when equipment failed.
- For some preventive maintenance problems, it took more than two years to reach an engineering resolution. (Presumably failures could have continued to occur during this time without the root cause being addressed or identified).
- There is inadequate communication about failure analysis between technical support groups and maintenance groups.
- System engineers have limited time to monitor the system for which they are responsible.
- Reports typically did not identify repetitive failures over a long period, subtle trends, or component failure trends. (This could result in oversight of problems requiring root cause analysis).
- Documented information on completed work packages was not adequate to assist in root cause analysis.

Our findings generally substantiate the NRC's findings.

3.7 Use of Probabilistic Risk Assessment

In Figure 2.1, the Maintenance Inspection Tree, under Part III, Maintenance Implementation, Section 5.0 involves Work Control. Specifically, sub-section 5.5, "Perform Work Prioritization," directs the NRC inspector to consider whether maintenance prioritization is based on PRA. Also, sub-section 5.7, "Establish Backlog Controls," lists whether backlog control is based on prioritization as an inspection item.

Generally, only a few utilities were using PRA. Of those which were using PRA, even fewer were using it specifically for maintenance decisions. Some utilities were in the process of implementing Reliability Centered Maintenance (RCM) programs for a limited number of the most important systems.

The most common use of PRA was for higher level decision-making, such as scheduling system outages, justifying limiting conditions of operation (LCOs), determining the importance of implementing modifications, and prioritizing their order of implementation. As expected, for the management of aging, none of the MTI reports mentioned modeling a plant PRA using time-dependent failure rates for the basic system components. Including time dependent failure modeling is the only way in which PRA can be used to manage aging. Current programs under NRC sponsorship to develop such modeling are still in the developmental stages.

4.0 INSIGHTS FOR SYSTEMS AND COMPONENTS

In the preceding section, the information extracted from the MTI reports was presented from the point of view of the broad programmatic functions, such as preventive maintenance, predictive maintenance, and failure trending analysis. While such a viewpoint is most useful in assessing the degree to which these functions had been addressed by the utilities at the time of the inspections, additional insights can be gained by sorting the information across these programmatic boundaries and concentrating on the information available for several important systems and components.

The following systems and components were selected for review for several reasons:

(1) They are significant contributors to the dominant accident scenarios of PRAs.

(2) They are the subject of several NRC bulletins, generic letters and information notices.

(3) They were often selected for concentration of inspection resources during the MTIs and so they appeared frequently as subjects of the MTI reports.

(4) They are the subject of previous system and component studies under the NPAR program so that the results of the current effort could be compared to the previous results.

Systems:

- Auxiliary Feedwater for PWRs
- Main Feedwater for both PWRs and BWRs.
- High Pressure Injection:

- High Pressure Coolant Injection (HPCI) and High Pressure Core Spray (HPCS) for BWRs.

- High Pressure Safety Injection (HPSI), Safety Injection (SI), and/or Charging System for PWRs.

- Service Water, and safety-related portions, such as Essential Service Water.

- Instrument Air, including compressors, and Emergency Diesel Generator Air Start System, for both BWRs and PWRs.

Components:

- Emergency Diesel Generators (EDGs).
- Electrical Components: Switchgear, breakers, relays, and motor control centers (MCCs)
- Motor operated valves, either general or involving the systems listed above.
- Check Valves.

As discussed in the previous section concerning programmatic insights for managing aging, the utilities do recognize that their structures, systems, and components are susceptible to aging. All the elements to mitigate aging exist within preventive maintenance programs. However, many programs were developed in reaction to the issues as they arose, rather than in a proactive manner. In addition, all the elements for a good PM program were not always fully developed and implemented at each plant site. Predictive maintenance, condition monitoring, trending, root cause analysis and use of PRA, and reliability methods were in the early stages of implementation, whereas post-maintenance testing and preventive maintenance and testing were more advanced.

Sorting the information from the MTI reports by systems and components provides a very useful alternative perspective. This sort yields a qualitative understanding of aging problems pertaining to specific systems or components. Preventive maintenance activities to mitigate these aging concerns are also discussed. Because of the nature of these MTI reports described in Section 2.2, no attempt was made to provide any quantitative assessments. However, the findings from the NPAR studies on these systems and components are compared to the current industry practices in managing aging as described in NUREG/CR-5643, "Insights Gained from Aging Research.[35] Examples of strengths and weaknesses in specific plant maintenance programs for systems and components are given in Appendix E.

4.1 Systems

The five systems selected for analysis were chosen because of their generally recognized importance, as evident from their appearance in the event trees of the most important accident scenarios of PRAs. The systems also are identified in several NRC bulletins, generic letters, and information notices. The analysis for each system follows.

4.1.1 Auxiliary Feedwater (AFW)

The AFW System in a PWR provides a safety-related mechanism for removing stored and decay heat from the reactor coolant system by transferring heat through the steam generators when the Main Feedwater System cannot be used to achieve shutdown. The AFW system is routinely used at many plants in support of normal startup and shutdown, as well as in response to emergency reactor shutdown.

4.1.1.1 Aging Insights

The AFW system is operated in support of normal startup and shutdown sequences, in response to plant transients (its safety related function), and for testing. During normal operation, it is in standby. The components of the AFW system are exposed to a variety of internal environmental conditions, ranging from high temperature steam to low temperature raw water.

Thus, the system is subject to a broad range of aging mechanisms in standby, including erosion, corrosion, and thermal fatigue. Aging during system operation occurs from operating the system at relatively low-flow conditions, which results in accelerated wear of pumps from hydraulically unstable conditions, and accelerated wear of check valves from the flutter that accompanies low-flow operation.

MTI Reports

Only a few relatively minor aging-related problems in the AFW Systems were noted in the 44 MTI reports. Some aging problems include pump seal leakage, valve packing leakage, and set point drift of I&C devices. In one case, vibration-induced failure of the IA system line caused the AFW regulating valve to fail to perform its design function. Because many AFW pumps are turbine driven, several cases were reported on the turbine driver, specifically the control system and the governor.

NPAR Study

Failure data from NPRDS were reviewed to determine which components were significant contributors to historical AFW system problems. Pump drivers were the principal source of system degradation. Almost three-fourths of the pump driver problems occurred with turbine drives.

The turbines, as a piece of mechanical hardware, have proven to be extremely rugged, but the control systems have frequently been unable to cope with the conditions demanded (rapid starts from cold conditions). Over half of the turbine drive problems were attributed to I&C or governor control system failures. Many of these failures occurred because of problems with turbine speed control.

Less than half of all AFW system failures reported to the NPRDS database were detected as the result of programmatic monitoring practices. Almost one-fifth of the system degradation associated with failed components was detected during demand starts. Almost one-third of the degradation associated with turbine I&C and governor control failures were detected during demand start conditions.

4.1.1.2 Managing Aging

Because AFW systems are one of the most important safety-related systems, utilities have concentrated upon providing good maintenance and surveillance programs for these systems to ensure their operational readiness. However, there are certain areas where the programs can be improved to mitigate aging problems that are not prevalent in the first few years of plant operation, but which can become prevalent as the plant becomes older.

MTI Report Findings

Preventive Maintenance - No PM programs to specifically manage aging were identified. However, some plants do have some elements of an effective PM program. Typical PM activities include adjusting pump packing, checking the operability of pumps and other ASME ISI/IST requirements for pumps and valves.

Predictive Maintenance/Condition Monitoring - Typical methods used include vibration analysis, oil sampling, thermography, checking pump differential pressure, and snubber testing. Although the manufacturer's recommendations specified a weekly test of the overspeed trip function of the AFW pump turbine, some plants did not have a program to routinely test this function. Similarly, weekly lubrication and cleaning of the moving parts of throttle/trip valves have sometimes been omitted.

Post Maintenance Testing - Routine PMT activities are valve stroking, VOTES or MOVATS diagnostic testing, and current signatures of MOVs and limit and torque switches.

Trending - The trending of test parameters for predicting the AFW system reliability was limited. One plant used the Computerized History and Maintenance Planning System (CHAMPS) for pump vibration data.

Root Cause Analysis - No RCA is performed on components failed during their normal operation. Superficial comments, such as normal wear, were cited to identify the failure mechanism. In one case, a failure modes and effects analysis (FMEA) performed for a turbine overspeed event was limited to studying the overpressurization of the turbine governor alone.

PRA/Reliability - No use of reliability methods for assessing the system was noted.

NPAR Study

The demonstration of the operational readiness of the AFW system depends upon a variety of testing and routine observations, including the following:

- *Pump testing.* The typical in-service test (IST) of an AFW pump is performed at low-flow conditions (through the minimum flowline). This testing provides only limited useful information on hydraulic performance, and is damaging to the pump. Periodic (i.e., at each cold shutdown) full flow testing should be performed to verify hydraulic performance of the pump, as well as the full load performance of the pump driver (motor, turbine, or diesel). The hydraulic performance (head and flow) of the pump, motor power, and machine vibration should be monitored and trended.

- *Power operated valve testing.* To the extent that IST of the power operated valves of the AFW system does not demonstrate design basis operability of a valve, the testing should be supplemented by periodic testing under conditions that as closely as practical represent design basis conditions (i.e., differential pressure, flow, etc.). Advanced diagnostic techniques, such as motor current signature analysis should be used.

- *Check valve testing.* In addition to the requirements for check valves associated with the IST program, advanced, non-intrusive diagnostic techniques should be used. The pump discharge line should be periodically monitored by operators (i.e., once per shift) or continuously monitored with instrumentation (thermocouples with remote alarm or readout) to ensure that main feedwater is not backleaking.

- *Turbine testing.* In addition to performance testing of turbines done in conjunction with pump testing, the turbine governor and speed control system should be calibrated periodically (i.e., every refueling). Proper functioning of overspeed trip devices should be verified monthly or quarterly.

- *Pipe examination.* Portions of the AFW system piping is exposed to stagnant raw water at many plants (i.e., piping from the backup water supply). This line is seldom or never used, and may be subject to considerable corrosion or other degradation (for example, microbiologically induced corrosion or Asiatic clam infestation). Programmatic controls should be in place to either examine the pipe periodically or to prevent degradation.

4.1.1.3 Conclusions for the Auxiliary Feedwater System

The summary and conclusions arising from the specific examples given in Appendix E, Section 1.1 are as follows:

Although AFWS are one of the most important systems in a PWR, there were several significant deficiencies concerning that system. For example, at Rancho Seco, the overpressurization of both trains of AFWS beyond the design stress values, resulting from the failure of the governor of the AFWS steam turbine-driven pump and its mechanical overspeed trip during a post maintenance test, was taken very seriously by the NRC, with a good portion of the MTI report devoted to that incident.

At other plants, such as Surry and Zion, the mechanical overspeed device of the turbine-driven pump was either never tested or 17 years had elapsed since the last test. These instances were cited as violations by the NRC.

Similarly, the NRC was concerned over poor maintenance practices such as at D.C. Cook where the vendor recommendation to adjust the AFWS pump packing leakage while the pump is operating was not incorporated into the maintenance procedure. This was cited as a violation because, although no problems had been noted, rotor seizure, scored shaft sleeves, or burned packing could have resulted.

Failures of AFWS MOVs to be repositioned after a manual reactor trip at St. Lucie Unit 2, as well as a consistent history of external leakage of AFWS discharge check valves from loose disc stops and missing stop welds at Fort Calhoun, appeared to be aging-related.

The most prominent positive features noted pertained to condition monitoring techniques applied to AFWS pumps, such as vibrational analysis, oil sampling, and measurement of pump differential pressure.

4.1.2 Feedwater Systems

In a BWR, the Feedwater (FW) System pumps water from the main condenser to the reactor vessel. In a PWR, the FW system pumps water from the steam generators to the reactor vessel. The FW control system controls the flow of feedwater, and in a BWR it controls the speed of the reactor feed pump turbines and the position of the feed pump bypass valve. High pressure FW heaters represent the last stage of feedwater heating before entering the vessel.

4.1.2.1 Aging Insights

MTI Reports

Unlike the AFW System, the FW Systems have shown significant aging problems, including wall thinning of piping systems induced by erosion/corrosion (Generic Letter 89-08), valve leakage from poor maintenance, pump seal leakage (a chronic problem), loose disc stops of check valves, bearing oil leakage, blockage of FW regulator valves from debris, o-ring failure in the FW heater control valve, and alignment problems with the FW speed increaser. The FW system is classified as a BOP system and operates continuously under hostile environmental and operating conditions, whereas the AFW system is a standby system. Because of its BOP classification, maintenance performed on components within this system sometimes receive inadequate attention. In the FW control system, capacitors, density correction instrumentation, cascade switches, and controllers were identified as age-sensitive components.

NPAR Study

No aging study of the Feedwater System has been performed. However, a preliminary study on balance of plant (BOP) systems indicates that the number of plant scrams, power reductions, and shutdowns initiated by the failure of this system can increase as the plants become older.[36]

4.1.2.2 Managing Aging

MTI Reports

Because of its BOP status, there often are no preventive maintenance programs dedicated for this system. However, awareness of aging problems and implementation of scram reduction programs have prompted utilities to develop PM programs to ensure its reliable operation.

Preventive Maintenance - Some plants have upgraded the FW system and the FW control valve important to safety, thereby providing better maintenance and monitoring programs. FW pump bearings are inspected regularly. Some use the FW heater performance to ensure plant efficiency.

Predictive Maintenance/Condition Monitoring - Some plants have selected this system for reliability centered maintenance programs, and therefore, as the subject of predictive maintenance techniques.

Post Maintenance Testing/Trending/Root Cause Analysis/PRA - Only limited activities were noted for these aspects of the PM program.

NPAR Study

No aging study of this system has been performed. Therefore, no comparison can be made to NPAR results.

4.1.2.3 Conclusions for Feedwater Systems

The specific insights shown in Appendix E, Section E.12, lead to the following conclusions concerning the most significant insights. Leakage of MFW pump seals, either oil or water, was the most common aging-related failure or degradation in the MFW system observed by the NRC. MFW flow control valves were sometimes noted for their high frequency of maintenance.

At at least one plant, an Important-to-Safety category was established, which included Feedwater pumps and control valves. At plants which had a Reliability Centered Maintenance program, MFW was often included.

Condition monitoring techniques for monitoring pipe wall thinning from erosion and corrosion were applied to many different lines on the BOP side, such as extraction steam and heater drains. Rotating equipment sometimes identified as being subject to vibration monitoring included the MFW pump turbines and the condensate pumps. MFW pumps also were subjected to oil sampling.

On the negative side, deficiencies were noted in the documentation of maintenance records. The records were sometimes ineffective for trending and root cause analyses. The root cause analyses were sometimes superficial, citing symptoms, not causes.

4.1.3 High Pressure Injection Systems (HPIS)

The two main BWR high pressure injection systems (HPISs) are high pressure coolant injection (HPCI), which includes a steam turbine-driven pump, or high pressure core spray (HPCS), which includes a motor-driven pump with a dedicated diesel generator. The main purpose of the HPIS is to permit injection of coolant into the reactor vessel at reactor pressure up to 1120 psia for a wide variety of transients and accidents. The PWR HPIS provides high pressure injection of borated water by means of motor-driven pumps to prevent uncovering of the core for small LOCAs and to delay the point at which core uncovery would occur for intermediate sized LOCAs until the intermediate and low pressure injection systems can begin injection into the core. The HPIS can also be used to cool the core following a reactor shutdown when heat removal by the steam generator cannot be achieved. For some plants, the HPIS provides normal primary coolant system charging and provides seal injection water for the reactor coolant pumps.

4.1.3.1 Aging Insights

In BWR plants, the system stressors which contribute to age-related degradation include testing, operation, environment (pressure, temperature, humidity, radiation), vibration, dirt, foreign material, water hammer, improper lubrication, and improper maintenance. Dominant-failure mechanisms include wear, fatigue, setpoint drift, or out-of-calibration instrumentation.

In PWR plants, aging is a concern for the HPIS. The NPRDS and Nuclear Power Experience (NPE) databases show that about 21% to 28% of the failures are aging-related. The most frequent failures that may be age-related are electrical and mechanical control malfunctions for pumps and valves. Boron crystallization from leaking packing and seals or faulty heat tracing have caused valves and pumps to malfunction. Leaking of borated water on to carbon steel parts of HPIS components and on adjacent systems has caused corrosion. Of special concern is a potential for fatigue failure of the stainless steel pipe and nozzles resulting from loose thermal sleeves or valve seat leakage.

MTI Reports

Problems related to HPCS and/or HPCI pumps include worn parts in the pump output breaker, excessive grease at lower motor bearings, and oil leakage in the bearing housing. MOV related failures include corrosion of the valve body and packing leaks. Oil leakage from the gear reducer, damaged flexible conduit, binding and broken instrument sensing lines and trip coil burnout in 4.16 kv breakers are among other aging problems. In the case of SI pumps, heavy buildup of boron at the upper seal has been reported at several plants.

NPAR Study

The most commonly failed BWR HPIS components included valves, valve operators, instrumentation and control (I&C), pumps, turbines, pipe, and pipe supports. The most common failure modes for the components identified above include degraded operation (valves, valve operators, and turbines), loss of function (I&C), low injection flow (pumps), leakage (pipe), and failure to operate (pipe supports). The failure data bases indicate 46 to 68% of the failures were not detected by surveillance testing. Approximately 11.4% of the failures in the LER database resulted in a failure of the system to operate, and 8.4% of the failures in the NPRDS database resulted in a complete loss of system function. The components that most often caused a complete loss of function were valve operators, valves, circuit breakers, mechanical controllers, bistable switches, and the turbine.

The effect of component failure on the PWR system's performance was determined from the NPRDS data.

Approximately 57% of the failures caused either degraded operation, loss of redundancy or loss of channel, which implies reduced reliability if the system were called on to perform its safety function. Because of component redundancy, only 0.7% of the failures actually caused a loss of system function. The relative frequencies of HPIS components failures were determined from the NPE data. Valve failures were the dominant failure. Also, a probabilistic risk analysis of the system showed that the failure of valves to open contributed the most to system unavailability. The Nuclear Power Experience (NPE) listed mechanical disability as the most frequent potential cause of aging related failure. Others were local I&C failures, setpoint drift, subcomponent sticking, short/ground, and weld failures.

Loose thermal sleeves have lead to a through wall fatigue crack in one plant and cracks with up to 25% penetration in five other plants. The cracks occurred in the weld at the safe end and were caused by thermal fatigue resulting from makeup flow cycling on and off and initiation of high pressure injection flow. Thermal sleeves have been redesigned to prevent loosening, and a continuous makeup flow is maintained to prevent thermal cycling, which thereby prevents cracking. Leaking valves have lead to thermal fatigue and cracks in the base metal, welds, and the heat affected zone of the elbow between the hot leg and the first check valve at two plants. The leaking valves allowed cold water to flow into the hot section of the injection line causing stratified flow that led to the fatigue failure. Enhanced ultrasonic testing was required to detect the cracks after leakage was observed.

4.1.3.2 Managing Aging

Because this system is one of the emergency core cooling systems (ECCS), like the AFW System, these systems are subjected to a maintenance program appropriate for a safety-related system. However, most activities are primarily dictated by plant technical specifications, vendor recommendations or other regulatory requirements arising from 10CFR50, Appendix B. No dedicated program to manage aging of HPI systems was noted in the MTI reports.

MTI Reports

Preventive Maintenance - Several reports cited poor PM programs for systems. However, some plants have been upgrading their MOV PM program by enhancing the failure analysis, planning preparation, scheduling, PMT, and communications among the responsible plant staff.

Predictive Maintenance/Condition Monitoring - Diagnostic testing of MOVs has been introduced in some plant PM programs. Insulation resistance testing, vibration monitoring, stator winding and bearing temperature monitoring, thermography, and lube-oil analysis are methods used to monitor pumps and valves. Some plants are developing RCM programs for this system.

Post-Maintenance Testing - Valve stroking, verification of limit switch and torque switch settings and output, and use of the VOTES and MOVATS methods are some of the means used to assure the operability of valves. No other component was specifically mentioned for PMT.

Trending/Root Cause Analysis - There were no programs or poorly structured programs in these two areas.

PRA/Reliability Modeling - Because these systems are typically modelled in the plant PRA, some plants have used their PRA results to prioritize maintenance activities on HPI components.

NPAR Study

Improved preventive maintenance programs were identified as one area under utility control that could result in improved HPIS reliability. The preventive maintenance programs applied to BWR HPISs vary widely from plant to plant. The following factors should be included in a preventive maintenance program:

(1) A quality system that requires records on all maintenance of safety-related systems and components and verification of installation and changes in status following calibration.

(2) A HPIS room free of contamination to improve ease and accuracy of maintenance and inspection.

(3) Inspection of the equipment room each shift to check for leaks.

(4) Measurement of motor current while cycling a valve following maintenance work on the valve or valve operator.

Valves and valve operators were listed within the top two or three most commonly failed components in all four data sources for this study. Wear is the leading cause of failure for these components. NRC IE Bulletin 85-03 and Generic Letter 89-10 recognize the need for better methods for analyzing MOV performance and detecting MOV problems. Diagnostic equipment developed in response to the NRC concerns expressed in IE Bulletin 85-03 and Generic Letter 89-10 may meet this need.

In PWR plants, a preventive maintenance program should be in place for the HPIS. The PM program should include periodic testing, monitoring, and inspecting to detect degradation and replacement or repair before failure. Technical specifications require quarterly inservice testing of pumps and valves in accordance with Section XI of the ASME Boiler and Pressure Vessel Code. Pump testing should be supplemented with electrical characteristic measurement of the motor to detect degradation of electrical insulation and other electrical components. The Aging Assessment Guide for Motors contained within NUREG/CR-5643 provides guidance applicable to the pump motors.

Valves are the most troublesome component of the HPIS. The stroke time tests required for Section XI are not effective in monitoring aging. The Aging Assessment Guides for Motor-Operated Valves and Check Valves also contained within NUREG/CR-5643, provide guidance for inspection and maintenance of these valves. Also, the diagnostic testing required by Generic Letter 89-10 will help insure the operational readiness of the motor-operated valves.

Malfunctions and failures of pump and valve control circuits have been the leading problems with HPIS operation. These circuits should be tested periodically to demonstrate they are functioning properly.

Frequent visual inspections to detect and repair leaks will avoid the problems of boron crystal build-up in pumps and valves and boric acid corrosion of carbon steel parts. Careful monitoring of thermal sleeve integrity and valve leakage and implementing operating practices that reduce thermal cycles will prevent cracking of the pipes and nozzles from thermal fatigue. This monitoring should be supplemented by enhance ultrasonic testing of the welds and high stressed areas of the base metal.

4.1.3.3 Conclusions for High Pressure Injection Systems

From the specific examples concerning the HPI systems presented in Appendix E, Section 1.3, the following conclusions can be drawn:

As with the Main Feedwater system, oil leakage was a common problem with HPI pumps at either PWRs or BWRs. Leakage also was noted on MOVs, including heavy buildup of boric acid resulting from degradation of the stem and packing.

Good maintenance practices were noted at some plants, such as the HPCI Maintenance Improvement Program at Dresden, which included an MOV upgrade and preventive maintenance program, and enhancement of failure analysis and post maintenance testing. Examples of satisfactory maintenance and documentation for the HPI systems also were noted. In many cases, condition monitoring techniques, such as MOVATS were applied to HPI MOVs, and vibration analysis was performed on HPI pumps.

Some examples of poor maintenance practices included a cover gasket for a limit switch/torque switch being in a degraded condition on a Component Cooling Water to charging pump MOV. The valve was an environmentally qualified (EQ) component. Also, some IEEE standard maintenance practices were not implemented for motors in the Safety Injection System at one plant. In some cases, vendor recommendations also were inadequately incorporated.

Root cause analyses were either inadequately performed or not performed at all. At Hatch, no root cause failure analysis had been performed after a HPCI MOV failure.

In general, although the High Pressure Injection systems are important for mitigating many accident scenarios, there were several significant maintenance-related deficiencies noted by the NRC, such as inadequate maintenance practices and post maintenance testing criteria, and failure to conduct root cause analyses.

4.1.4 Service Water System

Service water systems (SWSs) in nuclear reactors perform vital safety functions, as the final link between the reactor and the ultimate heat sink (river, lake, cooling pond). The systems also provide essential cooling to safety-related equipment, such as emergency diesel generators and emergency core cooling systems. Depending on the design, all or part of the system will be exposed to raw water. Therefore, the SWS components (pumps, valves, pipes, heat exchangers) are subject to a wide range of corrosion mechanisms.

4.1.4.1 Aging Insights

The SWS is subject to several age-related degradation problems. A study issued in 1988 by the NRC's Office for the Analysis and Evaluation of Operational Data (AEOD)[37] indicated that the SWS at U.S. nuclear plants has a degraded performance rate of 0.4 per reactor year and a complete system failure rate of 1.5×10^{-2} per reactor year. Mechanisms related to age-related degradation caused approximately 60% of the SWS degradation events. The principal degradation mechanisms were corrosion, biofouling, and wear.

MTI Reports

A major problem experienced at several plants has been pipe wall thinning from erosion and corrosion. At Salem, through-wall leaks at the welded joints in some carbon steel piping and corrosion and erosion of stainless steel piping stimulated a program to replace the system piping with 6% molybdenum stainless steel. The system piping also was rerouted to reduce turbulence.

Other significant component failures were noted. At Limerick, the absence of chemical treatment of the ESW spray pond resulted in system valves and piping becoming filled with scale and sludge. At Indian Point 3, a 10" SW return line from a containment fan cooler failed due to the presence of chlorides.

Examples of some other age-related problems include chloride-induced stress corrosion; pump shaft wear caused by packing problems; severe corrosion of couplings, valve bodies, and pump surfaces; seal and packing leaks in pumps and valves; accumulation of dirt at relay and switch contacts; and vibration of the system caused by water hammer.

NPAR Study

In open (once-through) SWS types, corrosion was the largest contributor to failure. Biofouling has been a major concern at some plants, from infestation of species such as Asiatic clams and Zebra mussels. In closed types of SW systems (intermediate heat exchangers), the largest cause of functional failure was biofouling of the heat exchangers, followed by corrosion of valves. In recirculating types of SW systems (spray ponds or cooling towers), corrosion was the largest failure cause, predominantly affecting valves and sensors.

Failure of valve operators has been a major problem with SW systems, but the cause is generally related to corrosion. Heat exchanger failures occur predominantly by plugging from biofouling, but corrosion also is a significant mechanism. Large pipes degrade from corrosion; small pipes also are susceptible to plugging from biota or sedimentation. Sensors fail by corrosion and by buildup of deposits.

4.1.4.2 Managing Aging

Because the SW system is a highly important, safety-related system, the components within this system also are subjected to a PM program. However, the system uses raw water from an outside source, which is typically very harsh and deteriorates components faster than expected. Again, its continuous operating status during the plant's normal operation accelerates the aging process. Utilities are chemically treating the water to prevent corrosion and taking other preventive measures to avoid microbiologically-influenced corrosion.

MTI Reports

Preventive Maintenance - Some plants are upgrading their SW systems to improve performance. However, there are several negative points cited in the MTI reports, including: delay in inspecting, cleaning and rebuilding certain system valves, faulty fasteners resulting in loose pump motor conduit, additional PM activities needed to halt further system degradation, improper recoating of SW piping, use of an air-operated wrench to make up system joints in violation of plant procedures, sludge and scale contamination resulting from a lack of chemical treatment of the SW spray pond, and a 3-year-old outstanding work order on a system check valve. Fifty percent of the IEEE Maintenance Good Practices for SW pumps were not performed at one plant and some plants did not incorporate vendor maintenance recommendations.

Predictive Maintenance/Condition Monitoring/PMT - SW systems were incorporated into RCM programs at Calvert Cliffs, Ginna, and D.C. Cook. Advanced monitoring techniques (vibration, bearing temperature) were incorporated into the PM program at Ginna, H.G. Robinson, and Indian Point 3. Differential pressure measurements were taken quarterly at McGuire, thre. material test loops were installed at Salem to monitor various system parameters. Video tape records were made of check valve internals. System check valves were not inspected for wear and degradation, procedures for check valve inspection did not contain specific data, including the lack of specific dimensions to be checked and the use of the results to adjust PM frequency. At Cooper, post-maintenance testing on system components was not consistently performed, and there were no maintenance records for two SW MOVs.

Trending/Reliability/PRA - No significant activities in these areas were noted in the MTI reports.

Root Cause Analysis - The RCA of the failure of a SW heat exchanger at H.B. Robinson was thorough and accurate. Recurring failures of SW control valves were identified by maintenance technicians rather than by engineering evaluation. At Cooper, equipment failed because plant procedures did not specify when to perform RCA. At Indian Point 3, a RCA did not correctly identify the cause of SW pipe failure as due to chlorides in the service water. At Limerick, flow conditions in SW piping were not correctly modeled, and root cause analysis of SW system corrosion did not identify all the failed components. At Vermont Yankee, although trending indicated an increase in the failure rate for a SW pump, plant or corporate management was not notified.

NPAR Study

Effective root cause analysis is essential to understand the causative factors before implementing strategies to mitigate aging. For the aggressive and varied degradation factors found in SWS, it is important to differentiate degradation caused by corrosive chemistries from degradation caused by biological species [i.e., microbiologically-influenced corrosion (MIC)].

A necessary element to minimize degradation in any type of SWS is effective control of water purity and chemistry. Where confirmed biological agents are active, a biocontrol program (chemical, thermal) is required. Environmental regulations can limit the extent to which some of these solutions can be pursued, and a careful consideration of alternatives is necessary to select the most cost-effective solution. Any changes to the control program should be accompanied by monitoring for induced stressors (i.e., removal of nickel from Cu/Ni heat exchangers by a chlorination biocide).

4.1.4.3 Conclusions for the Service Water System

From the specific examples concerning the Service Water System presented in Appendix E, Section 1.4, the following conclusions can be drawn:

Several plants were well aware of problems in their Service Water systems caused by corrosion and erosion and had either begun or planned to take corrective actions. The most notable was at Salem, where through-wall leaks at weld joints in carbon steel piping, and corrosion and erosion of stainless-steel piping caused the utility to begin replacing SW piping with 6% molybdenum stainless steel and to reroute lines to reduce turbulence. Completion was scheduled for 1995. Poor material conditions involving rust on SW piping and supports, were noted at several plants. Water leakage was observed on some valves.

The SW system was included in the Reliability Centered Maintenance programs at several plants. Also, several plants monitored the vibration of the SW pumps. At Fitzpatrick, the internals of SW system check valves and adjacent piping were videotaped during assembly, using state-of-the-art fiber optic equipment.

Poor maintenance practices were noted at some plants, such as at Salem, where SW header piping was recoated with Belzona-R Mastic, with insufficient curing time for the ambient temperature. No chemical treatment was being applied to the ESW spray pond at Limerick, so that ESW piping and valves became filled with sludge and scale. Examples of failure to incorporate industry-recommended maintenance practices were cited, such as failure at H.B. Robinson to incorporate half of the IEEE standard maintenance good practices for motors. At Shearon Harris, North Anna, and H.B. Robinson, some vendor recommendations for SW pumps and components were not incorporated.

Acceptance criteria for condition monitoring and inspecting check valve internals were inadequately specified at H.B. Robinson and McGuire. At Robinson, neither a surveillance nor a PM program existed for the discharge check valves of the SW booster pump. At other plants, examples of inadequate or ambiguous post-maintenance testing specifications also were cited.

Several examples were noted of inadequate root cause analysis involving SW components. At Cooper, a wetted service solenoid pilot valve, which was identified as an example of equipment degradation, did not result in a root cause analysis, because there was no clear trigger mechanism beyond that identified in plant procedures. At Indian Point 3, the failure analysis of a ten-inch containment penetration of the SW return line from a fan cooler unit did not identify that it was caused by chlorides in the service water.

Generally, the MTI reports suggested that while there were many examples of inadequate maintenance activities for SW systems, utilities were conscious of SW as a problem system which warranted increased attention. Presumably, some of this awareness has been sparked by NRC Generic Letter 89-13[38,39] concerning bio-fouling of safety-related equipment.

4.1.5 Instrument Air and Emergency Diesel Generator Air Start Systems and Compressors

Air systems are used in nuclear power plants to actuate or control equipment that is vital to normal plant operation as well as to shutdown the plant safely during an abnormal or emergency condition. Aging degradation occurs in the compressed air system and becomes an increasing factor as the system ages. The external systems most often affected by IA degradation are containment isolation, main feedwater/main steam, auxiliary feedwater and BWR scram systems. Because aging processes affect the compressed air system and its components, an aggressive preventive maintenance program should be followed to mitigate these effects. The air system usually includes the compressors, filters, dryers, and distribution piping.

4.1.5.1 Aging Insights

Air systems were originally not classified as important to safety. Dedicated accumulators for particular safety functions and fail-safe assumptions in the design allowed the utilities to categorize these systems as non-safety. An AEOD study found that inadequate and faulty design assumptions on fail-safety position and leaking of accumulator check valves have prompted the utilities via Generic Letter 88-14[40] to improve the reliability of these systems.

MTI Reports

Typical age-related problems include contaminated air with hydrocarbons, dessicants, and moisture. Several valve internals have become either corroded or sticky with gummy substances from hydrocarbons. In several cases, while blowing down the lines, substantial amounts of water were found in the line. Poor air quality or excessive leakage have been noted. Crimped tubing, clogged filters, and wet dessicants, caused by delayed and improper preventive maintenance, also were observed.

NPAR Study

Few events occurred in which a total loss of air took place. Partial loss or degraded system operation were most common. Several cases led to reactor scrams and some introduced transients into safety systems they serve. Moisture and particles in the air system, and hydrocarbon contamination caused numerous failures of components in the air system. Data were obtained from six nuclear plants and sorted to determine the distribution of air system failures among the major components.

The components experiencing the most failures due to aging degradation were compressors, air system valves, dryers and filters.

(1) *Compressors.* Failures were largely attributed to wear from normal service. Degraded operation resulted from failing to load/unload properly, and leakage.

(2) *Valves.* Wear and corrosion accounted for more than half of the failures associated with air system valves, and resulted in an inability to open or close manual and power operated valves. Seat leakage also was a common failure mode.

(3) *Air Dryers.* The dominant failure mechanisms are blocking or clogging, corrosion, deterioration, and contamination. These mechanisms resulted in the delivery of compressed air with a higher dewpoint than specified.

(4) *Filters.* Blocking and clogging were the major failure mechanisms on the pre-filters and after-filters. This severely diminished the air flow in several cases.

measurements were taken quarterly at McGuire, three material test loops were installed at Salem to monitor various system parameters. Video tape records were made of check valve internals. System check valves were not inspected for wear and degradation, procedures for check valve inspection did not contain specific data, including the lack of specific dimensions to be checked and the use of the results to adjust PM frequency. At Cooper, post-maintenance testing on system components was not consistently performed, and there were no maintenance records for two SW MOVs.

Trending/Reliability/PRA - No significant activities in these areas were noted in the MTI reports.

Root Cause Analysis - The RCA of the failure of a SW heat exchanger at H.B. Robinson was thorough and accurate. Recurring failures of SW control valves were identified by maintenance technicians rather than by engineering evaluation. At Cooper, equipment failed because plant procedures did not specify when to perform RCA. At Indian Point 3, a RCA did not correctly identify the cause of SW pipe failure as due to chlorides in the service water. At Limerick, flow conditions in SW piping were not correctly modeled, and root cause analysis of SW system corrosion did not identify all the failed components. At Vermont Yankee, although trending indicated an increase in the failure rate for a SW pump, plant or corporate management was not notified.

NPAR Study

Effective root cause analysis is essential to understand the causative factors before implementing strategies to mitigate aging. For the aggressive and varied degradation factors found in SWS, it is important to differentiate degradation caused by corrosive chemistries from degradation caused by biological species [i.e., microbiologically-influenced corrosion (MIC)].

A necessary element to minimize degradation in any type of SWS is effective control of water purity and chemistry. Where confirmed biological agents are active, a biocontrol program (chemical, thermal) is required. Environmental regulations can limit the extent to which some of these solutions can be pursued, and a careful consideration of alternatives is necessary to select the most cost-effective solution. Any changes to the control program should be accompanied by monitoring for induced stressors (i.e., removal of nickel from Cu/Ni heat exchangers by a chlorination biocide).

4.1.4.3 Conclusions for the Service Water System

From the specific examples concerning the Service Water System presented in Appendix E, Section 1.4, the following conclusions can be drawn:

Several plants were well aware of problems in their Service Water systems caused by corrosion and erosion and had either begun or planned to take corrective actions. The most notable was at Salem, where through-wall leaks at weld joints in carbon steel piping, and corrosion and erosion of stainless-steel piping caused the utility to begin replacing SW piping with 6% molybdenum stainless steel and to reroute lines to reduce turbulence. Completion was scheduled for 1995. Poor material conditions involving rust on SW piping and supports, were noted at several plants. Water leakage was observed on some valves.

The SW system was included in the Reliability Centered Maintenance programs at several plants. Also, several plants monitored the vibration of the SW pumps. At Fitzpatrick, the internals of SW system check valves and adjacent piping were videotaped during assembly, using state-of-the-art fiber optic equipment.

Poor maintenance practices were noted at some plants, such as at Salem, where SW header piping was recoated with Belzona-R Mastic, with insufficient curing time for the ambient temperature. No chemical treatment was being applied to the ESW spray pond at Limerick, so that ESW piping and valves became filled with sludge and scale. Examples of failure to incorporate industry-recommended maintenance practices were cited, such as failure at H.B. Robinson to incorporate half of the IEEE standard maintenance good practices for motors. At Shearon Harris, North Anna, and H.B. Robinson, some vendor recommendations for SW pumps and components were not incorporated.

Acceptance criteria for condition monitoring and inspecting check valve internals were inadequately specified at H.B. Robinson and McGuire. At Robinson, neither a surveillance nor a PM program existed for the discharge check valves of the SW booster pump. At other plants, examples of inadequate or ambiguous post-maintenance testing specifications also were cited.

Several examples were noted of inadequate root cause analysis involving SW components. At Cooper, a wetted service solenoid pilot valve, which was identified as an example of equipment degradation, did not result in a root cause analysis, because there was no clear trigger mechanism beyond that identified in plant procedures. At Indian Point 3, the failure analysis of a ten-inch containment penetration of the SW return line from a fan cooler unit did not identify that it was caused by chlorides in the service water.

Generally, the MTI reports suggested that while there were many examples of inadequate maintenance activities for SW systems, utilities were conscious of SW as a problem system which warranted increased attention. Presumably, some of this awareness has been sparked by NRC Generic Letter 89-13[38,39] concerning bio-fouling of safety-related equipment.

4.1.5 Instrument Air and Emergency Diesel Generator Air Start Systems and Compressors

Air systems are used in nuclear power plants to actuate or control equipment that is vital to normal plant operation as well as to shutdown the plant safely during an abnormal or emergency condition. Aging degradation occurs in the compressed air system and becomes an increasing factor as the system ages. The external systems most often affected by IA degradation are containment isolation, main feedwater/main steam, auxiliary feedwater and BWR scram systems. Because aging processes affect the compressed air system and its components, an aggressive preventive maintenance program should be followed to mitigate these effects. The air system usually includes the compressors, filters, dryers, and distribution piping.

4.1.5.1 Aging Insights

Air systems were originally not classified as important to safety. Dedicated accumulators for particular safety functions and fail-safe assumptions in the design allowed the utilities to categorize these systems as non-safety. An AEOD study found that inadequate and faulty design assumptions on fail-safety position and leaking of accumulator check valves have prompted the utilities via Generic Letter 88-14[40] to improve the reliability of these systems.

MTI Reports

Typical age-related problems include contaminated air with hydrocarbons, dessicants, and moisture. Several valve internals have become either corroded or sticky with gummy substances from hydrocarbons. In several cases, while blowing down the lines, substantial amounts of water were found in the line. Poor air quality or excessive leakage have been noted. Crimped tubing, clogged filters, and wet dessicants, caused by delayed and improper preventive maintenance, also were observed.

NPAR Study

Few events occurred in which a total loss of air took place. Partial loss or degraded system operation were most common. Several cases led to reactor scrams and some introduced transients into safety systems they serve. Moisture and particles in the air system, and hydrocarbon contamination caused numerous failures of components in the air system. Data were obtained from six nuclear plants and sorted to determine the distribution of air system failures among the major components.

The components experiencing the most failures due to aging degradation were compressors, air system valves, dryers and filters.

(1) *Compressors.* Failures were largely attributed to wear from normal service. Degraded operation resulted from failing to load/unload properly, and leakage.

(2) *Valves.* Wear and corrosion accounted for more than half of the failures associated with air system valves, and resulted in an inability to open or close manual and power operated valves. Seat leakage also was a common failure mode.

(3) *Air Dryers.* The dominant failure mechanisms are blocking or clogging, corrosion, deterioration, and contamination. These mechanisms resulted in the delivery of compressed air with a higher dewpoint than specified.

(4) *Filters.* Blocking and clogging were the major failure mechanisms on the pre-filters and after-filters. This severely diminished the air flow in several cases.

4.1.5.2 Managing Aging

In response to NRC Generic Letter 88-14, utilities are upgrading their air systems and developing better preventive maintenance programs.

MTI Reports

Preventive Maintenance - Lack of regular PM for filters, dryers, and compressors resulted in many age-related problems. Recently, plants implemented specific programs aimed at upgrading system reliability and assuring fail-safe capability, added biweekly blowdown of the system, and included the IA system in the IST program to check system operability.

Predictive Maintenance/Condition Monitoring - Several plants have considered including the IA system within an RCM program.

PMT/Trending/RCA/PRA - There were no specific activities in these areas.

NPAR Study

(1) Frequent monitoring, including system walkdowns and visually inspecting key equipment, should be a routine part of the maintenance program for the IA system. The frequency of inspections and walkdowns on air receivers, piping, aftercoolers, and valves should be increased as the system ages.

(2) Degraded pressure operation is the most common failure mode seen in the air system. Emergency procedures for response to and recovery from degraded air system events should be developed, along with procedures for the response to and recovery from the complete loss of air.

(3) Periodic testing for gradual loss of pressure should be performed to test the performance of safety grade accumulators, check valves, and isolation valves under these conditions.

(4) Air system valves should receive more maintenance, particularly IA/SA cross connection valves, or low pressure isolation valves.

Air Intake and Filter: Interior surfaces should be free of rust and dirt. Filters should be changed periodically to preclude high differential pressures (dp). This pressure and its associated instruments should be monitored; an unusually low dp could indicate a broken filter screen.

Air Compressors: Oil samples should be taken to determine if water intrusion or particulate buildup has occurred. Such sampling will effectively supplement bearing vibration and temperature monitoring.

Intercoolers and Aftercoolers: Periodic inspection and cleaning of the heat exchanger tubes will ensure that heat transfer capability has not been affected due to corrosion buildup.

Driers: The outlet dewpoint should be checked, preferably by on-line instrumentation. The drier skid contains several important valves used for switching towers or blowing down excess moisture. Proper operation and alignment of these valves is necessary to assure proper IA system operation.

Valves: In the distribution of air to the plant, solenoid operated valves and manual valves are used. These should be cycled periodically for freedom of movement. At various locations in the distribution system, blowdown valves should be operated to remove desiccant fines and moisture.

4.1.5.3 Conclusions for the Instrument Air and Emergency Diesel Generator Air Start Systems

The specific examples cited in Appendix E, Section 1.5, for the air systems, lead to the following conclusions:

Very significant aging-related problems were noted in the EDGAS at Surry. The problems were the deterioration of the compressor valve caused by moisture and unavailability of replacement valves, which, therefore, required that the six air compressors be replaced. There was no program for monitoring or controlling EDG air-starting quality, and there was a high likelihood that the air-start receivers were full of rust and scale from years of wet service. Also at Surry, the leakage in the Instrument Air system header was 47 CFM, which the NRC considered excessive. The utility had not serviced all accumulators to eliminate blow-by, nor had it walked down the system to identify and repair all leaks. Problems were also noted in the system supplying IA to the containment at Surry. The drier filters had not been replaced since installation seven years earlier, and the system could not maintain the required dew point of 35°F, even under optimum conditions.

Problems were noted, such as those at Palisades, where an emergency diesel generator could not be started because the air compressor would not operate. Replacement of the motor thermal overload, which had tripped and would not reset, did not correct the problem.

At ANO, the NRC noted that there was a lack of awareness of plant aging of non-safety related equipment, as shown by the problems with the IA system, such as the numerous spare parts whose shelf life had expired. In addition, components containing similar parts still were in use without having had any refurbishment, even though the parts they contained had been in service longer than the parts in storage. This deficiency was attributed to an equipment trending program for BOP components that had not been implemented.

Other important deficiencies were noted, such as those at Shearon Harris where there were no formal preventive or corrective maintenance, operations, or surveillance procedures for the Rotary Air Compressor, even though that compressor was supplying 100% of the station IA requirements and the vendor recommended regular PM for both the compressor and air drier. Similarly, at H.B. Robinson, no PM had been established for the refrigerant air drier at the discharge of one of the IA system compressors, nor were important vendor requirements incorporated into the PM procedure for the compressor itself. Specifically, the vendor manual stated that establishing a wear rate for the teflon wear and seal rings "...cannot be overemphasized..." Worn rings can result in contact between the piston and the cylinder.

Deficiencies also were noted in post maintenance testing and failure trending. At St. Lucie, only major non-safety related equipment, such as IA compressors, was subject to PMT. There were no test methods and only vague instructions, such as "...test run and check for seal leakage..." The acceptance criteria were "...run a sufficient amount of time to determine if it performs its intended function..."

On the positive side, examples of rigorous and thorough root cause analyses were cited, such as at Cooper, where an IA drier post-filter housing had ruptured, causing a loss of air pressure to the MSIVs and a subsequent reactor trip. At Waterford, root cause analyses had been conducted for low flow of the IA and Station Air compressors and premature degradation of compressors.

Generally, the IA and EDG Air Start Systems were inadequately maintained at several plants. Also, some experts have noted that periodic air sampling programs are not commonly in use and that there is no agreed upon standard for air quality.

4.2 Components

The data were sorted for the following components:

(1) Emergency Diesel Generators
(2) Electrical Components: Switchgear, Breakers, Relays and Motor Control Centers (MCCs)
(3) Motor Operated Valves
(4) Check Valves

As for the systems selected, the components were chosen because of their generally recognized importance, as shown by their contribution to the dominant accident scenarios of PRAs. Also, the components have been the subject of several NRC bulletins, generic letters, and information notices. NPAR studies have been performed for all of the above components. A comparison to the NPAR results also are presented.

4.2.1 Emergency Diesel Generators

The EDG system typically consists of at least two diesel generators, rated at 2,500 to 10,000 hp each. The potentially serious consequences of an aging related failure of these EDG systems has directed renewed attention to improvements in testing, maintenance, and management to reduce aging stressors and improve reliability. Certain practices for testing and engine load management can minimize the effect of aging. The air-start system, which is part of the EDG system, was discussed in Section 4.1.5.

4.2.1.1 Aging Insights

Aging is a concern of EDG systems. The evaluation of multiple data bases showed that more than 50% of the failures were attributed to aging. Different aging mechanisms are present, related to the operating status of the system. While in standby, the aging mechanisms are:

- corrosion,
- set point drift,

- chemical attack from fuel and lube oils, and
- environment, dust, microbial growth

While the system is operating, the aging mechanisms include:

- vibration,
- thermal and mechanical shock,
- excessive operating loads, and
- operating environment.

Operational aging stressors are enhanced by the synergistic influences of current technical specification requirements with respect to cold starts and engine loading.

MTI Reports

A large percentage of failures of the EDG occurs in the air start system, which was discussed in Section 4.1.5. Other age-related problems include oil leaks in the cylinder heads, degradation of the motor for the jacket cooling pumps, water leakage in the jacket water heat exchanger, and degraded starting logic circuits. Several problems are related to the generator and associated components, such as valves, gauges, and tubing.

NPAR Study

The effect of each EDG failure on system performance was determined from the NPAR data base developed for the EDG system. Over half of the failures were judged to be related to aging and about one-third resulted in the loss of function. Failures typically did not occur in either the engine or the generator, but occurred chiefly in the supporting instruments and mechanical components of the engine sub-systems. The contribution from failures of I&C components was about 30%, while the lubrication, fuel oil, cooling and starting subsystems each contributed about 10% to the additional failures observed. Failures directly attributable to the engine and generator were less than 15%.

4.2.1.2 Managing Aging

Because EDGs serve a vital role in the safety of nuclear power plants, specifically in the loss of off-site power and station blackout scenarios, maintenance and operability checks are performed regularly to keep these components in operationally ready condition. Most PM activities are based on good practices applied to the diesel engines used in non-nuclear applications for the last half century. Accelerated degradation because of cold starts during surveillance testing was identified by the NRC as a problem in Generic Letter 84-15.[41] This problem was later addressed indirectly in Regulatory Guide 1.155,[42] which concerns Station Blackout, through the establishment of target reliability levels for EDGs.

MTI Reports

Preventive Maintenance - Most PM activities based on vendor recommendation and good maintenance practices are being performed in the nuclear industry. Some of these activities include periodic inspections, insulation resistance testing (meggering), checking oil leaks, surveillance testing, and air-start system checks.

Predictive Maintenance/Condition Monitoring - Exhaust gas monitoring, chemical analysis of water vapor in the lube oil, oil analysis, and vibration testing are among the techniques being used to monitor the EDG condition.

PMT/Trending/RCA/PRA - Only limited activities in specific areas were noted. Examples of lack of PMT after the calibration of process switches led later to the failure of the system. Root cause analysis and trending areas were generally weak. However, some plants did include the EDGs in their RCM programs.

NPAR Study

The operational readiness of the EDG system can best be assured by monthly condition monitoring and by changing certain harmful engine management practices. The monthly testing program should be redirected to monitor data on about 25 EDG operating parameters that could indicate degraded performance or impending component failure. NUREG/CR-5057[43] identifies the complete list of parameters and their chief uses for the recommended monitoring program. The test program and engine management should include pre-lubrication, slow loading, longer run times, and post-test gradual load reduction and cooldown practices.

Changes in the EDG system management that would result in the most beneficial engine improvements for aging mitigation and corresponding reliability improvements are to:

- significantly reduce the number of system starts,
- gradually add load to the system during test sequences, about 10-20 minutes,

- reduce test loads to 90% of continuous or the plant emergency EDG load, whichever is less,
- increase EDG start time to 25-30 seconds,
- eliminate short run times and excessive idle time, and
- include trending of the more important engine and generator operating parameters in the management program.

Seals, gaskets, and other components with short qualified life should be replaced at prescribed intervals. Cleaning, lubricating, and calibrating instruments and sensors should be performed periodically. However, periodic intrusive inspections, including component disassembly, should be reconsidered. Reliability may be improved by discontinuing such practices and using the monitoring and trending data and analysis results to identify maintenance needs.

4.2.1.3 Conclusions for Emergency Diesel Generators

For emergency diesel generators, the NRC identified one notable preventive maintenance practice in the program at Millstone 1 for dewatering the EDG fuel-oil storage tanks to control oxidation and bacterial growth. Also, at Indian Point 2, based on the positive results from a very extensive 12-year PM, recommended by the vendor, on one of the EDGs, the utility decided to perform a modified, reduced PM on the other two EDGs, even though they were not yet due for the 12-year PM.

In the area of condition monitoring, the emergency diesel generators were frequently selected for lube oil analysis. However, in one case, oil samples were taken from a stopped engine, downstream from a filter, rather than from a running engine, before filtration.

The NRC observed examples of adequate PMT, such as those at Calvert Cliffs where each component of the protective relaying of the EDG logic circuits, 480 V breakers, and the battery systems was subjected to PMT.

A good example of the Component Engineer concept was noted at Indian Point 3 where, for complicated tasks such as PM on an EDG, several component engineers may be involved, with one engineer assigned responsibility for the entire task.

Some negative aspects included a potential accelerated aging effect on one of the EDGs at Palisades, where a flow switch had been incorrectly bypassed for at least 8 months, thereby preventing the flow of heated oil to the upper engine block and bearing cylinder to aid in fast startup. The system engineer stated that if the flow switch is bypassed, under certain conditions, the engine would be stressed, accelerating aging and possibly causing harder starts, but that it would still start.

Poor PM practices were noted at several plants. At Palisades, a violation was cited because the threads of the terminal lugs for an EDG excitation panel were not fully engaged. At Dresden, the EDG excitation field breakers were not included in the PM program. Also, at Cooper, a violation was cited because there had been no Quality Control inspection of critical reassembly steps and clearance measurements.

Furthermore, there were several examples where vendor recommendations had not been incorporated. At Salem, one of the EDG cylinder heads was removed without a special lifting ring (identified in the technical manual) designed to accommodate the non-vertical angle. Important information was missing from the manual showing torquing and clearance specifications. At Clinton, 30% of mechanical and 47% of electrical PM tasks recommended by the vendor had not been incorporated. At Cooper, an EDG intercooler was so corroded that the vendor recommended replacement. The vendor manual recommended draining and flushing every 4 to 6 months, yet this was not in the utility's PM procedure, nor had the other coolers been inspected.

Root cause analysis was another area with some serious deficiencies. At Palo Verde, the utility had identified numerous failures of elbow fittings and drain plugs from corrosion in the EDG jacket water system. After replacing several parts, more of the same parts failed which had not been identified as subject to corrosion. The NRC cited as a violation the failure to take aggressive action to resolve the problem. At Duane Arnold, the NRC also cited as a violation the failure to take prompt corrective actions and perform a root cause analysis for problems with the thermal overloads of the EDG jacket cooling pump motors and associated contacts, which protect the motors from excessive fault currents. Violations also were cited for configuration control, such as at Palisades, where an incorrect revision of a drawing was used to modify circuit hardware in an EDG control panel.

Although the emergency diesel generators are critical for loss of offsite power, there were several serious deficiencies at some plants, which were cited by the NRC as violations. Increased attention to EDG maintenance is warranted at several plants.

4.2.2 Electrical Components: Breakers, Switchgears, Relays, and MCCs

Breakers and switchgears are part of the electrical distribution systems in a power plant. Relays and breakers serve important roles to feed electrical power to various electrical and electro-mechanical equipment which are vital for plant safety. Motor Control Centers (MCCs) are low voltage (less than 600 volts) controllers that start and stop, provide continuous power to, and protect motors that drive pumps and motor operated valves. Typically, a motor controller unit consists of a molded case circuit breaker, a magnetic contactor, a transformer, relays and thermal overload devices. Age-related degradation of these subcomponents has affected safety system availability and operation.

4.2.2.1 Aging Insights

The most frequent cause of failure was the buildup of dirt or other foreign substances that caused the electrical device to stick. More failures occurred in systems that function intermittently rather than continuously. The starter contactor may fail to close due to a non-uniform magnetic driving force caused by impeded armature motion. Most age-related failures are attributed to the circuit breaker and relay subcomponents. Setpoint drift and contact surface degradation are two dominant failure modes.

MTI Reports

Breakers and switchgears (starting from molded case to 4.1 kv or higher size units) are more often cited with age-related problems, such as dust contamination, corrosion of cabinet handles or other metallic parts, oil and water leaks, and corrosion or pitting of contact surfaces. In the case of MCCs, molded case breakers and relays are most often cited as problem areas. Sticking of start units and other mechanical linkages also was noted in MCCs and some relay units. Drifts in relay setpoints also were identified.

NPAR Study

The NPAR study has been limited to smaller size breakers and relays, and safety-related MCCs. Most breaker problems are typically identified as a result of arcing during tripping or closing. In several cases, control coils burnt up due to jamming of mechanical elements in the assembly, rather than due to aging of the coils. Other age-related events in relays include set point drift, short or open coils, binding or degradation of contacts, and misalignment. Most problems associated with breakers relate to switch contacts, trip latch mechanisms, overcurrent trip devices, racking mechanisms, linkages, coils, and closing release latches.

Operational data on nuclear plant components shows there have been significant failures of molded-case circuit breakers, relays, and magnetic contactors used in MCCs. The combination of circuit breakers and relays contribute to about 50% of all reported MCC failures.

4.2.2.2 Managing Aging

Aging degradation within electrical equipment, such as breakers and relays causes component failure more often than degraded operation, as might be the case for the rotating or mechanical equipment. The primary modes of failure are either failure to make the contacts or to open the circuit at the time of the demand. Because of this characteristic, aging effects must be mitigated in these electrical devices in their incipient stage.

MTI Reports

Preventive Maintenance: Typical PM activities include cleaning, inspecting, and lubricating moving parts, replacing or refurbishing worn parts, installing new parts, calibrating relays and meggering coils. Since these devices remain in one state (either open or closed) for a considerable length of time, intrusion of humidity, cabinet temperature, and other environmental conditions can be detrimental to their ability to operate. Preventive maintenance activities include cleaning and inspecting current carrying parts for overheating, binding or friction of moving elements, contact surface burning or pitting, and for uneven erosion of arc chutes or other internal parts. In several cases, vendor recommendations were not followed because of personnel shortages, protective devices were not included in the PM, and systematic procedures were not followed while perform ing the PM.

Predictive Maintenance/Condition Monitoring: Thermography was the only method cited in the MTI reports for condition monitoring of breakers.

Post-Maintenance Testing. Typical PMT activities include cycling the unit after the maintenance before its return to service. Sometimes, a contact resistance test is performed on auxiliary switches before and after the calibration.

Trending/RCA/PRA: No significant activities in these areas were noted.

NPAR Study

Several tests are useful in assessing the performance characteristics of the MCC, such as:

- Performing a continuity test following repair or replacement of a component.
- Checking mechanical and electrical properties of contactors, including verifying pickup and dropout voltages.
- Verifying circuit breaker and motor thermal overload trip setpoints and comparing the timing with manufacturer's data.
- Testing time delay relays, where applicable.
- Performing a final energized operational test of each control device.

A recent study on breakers and relays[44] found that the current activities for mitigating aging in breakers and relays are not effective for detecting significant aging degradation. Infrared thermographic measurement of auxiliary, control, protection, and timing relays, and for molded case and metal-clad circuit breakers is recommended. Vibration signature analysis for auxiliary, control, and timing relays, and for both molded case and metal-clad circuit breakers also is suggested. Inrush current signature for timing relays, dropout voltage, and trip duration for breakers, can detect aging problems. In addition to these non-intrusive methods, inspecting mechanical parts for any sign of deterioration is highly recommended.

4.2.2.3 Conclusions for Electrical Components: Breakers, Switchgear, Relays and MCCs

As shown by the specific examples from the MTI reports, which appear in Appendix E, Section 2.2 of this report, the NRC noted some examples of good responsiveness by the utilities to aging concerns of electrical equipment, such as at Rancho Seco, where the physical condition of switchgear appeared to be excellent, and interior plant electrical controls were free of moisture and foreign material. Also, at Sequoyah, PM procedures had been revised to inspect for cracks and to replace main toggle link pins in 6900 VAC circuit breakers. The pins had a significant failure rate early in plant life. The utility also determined that no silicon bronze bolts were used to splice bus bars in GE MCCs.

Good PM practices also were noted. Specifically, at Shearon Harris, approximately one-half of the switchgear received PM at every refueling outage. At Waterford, the GE Type AK-25 reactor trip breakers were returned for refurbishment every five years in response to GE's warning that the bearing grease may solidify after about seven years, possibly affecting breaker response time. The utility also trends the response times. Also, at Sequoyah, the procedure for PM on 6900 VAC switchgear included nearly all the beneficial steps recognized by industry, except for the anti-pump circuit, space heaters, blow out coil, and potential transformer compartments. A similar assessment was made of the PM procedure at Shearon Harris for medium voltage switchgear. Examples of satisfactory PM procedures for breakers and switchgear were cited at several other plants as well.

A few positive examples of post maintenance testing, failure trending, and root cause analysis also were cited, but not in significant numbers to draw conclusions.

There were some examples of untimely responses to aging concerns and neglect of circuit breaker maintenance. For example, at Duane Arnold, the NRC cited a violation because the utility had not adequately responded to a 1979 manufacturer's service advice letter concerning the premature wear of Tuf-LOC Teflon-coated fiberglass sleeve bearings in 4160 VAC breakers. The components affected included the RHR and Reactor Recirculation pumps, and other safety related components. At Dresden, the NRC also cited a violation for untimely responses to failures of SBM switches used in 4160 VAC breakers and cubicles.

At Dresden, despite a maintenance procedure specifying that 4160 VAC breakers be inspected and overhauled every five years or 500 operations, other untimely responses also were noted. Breakers for two of the Containment Cooling Service Water pumps had last been overhauled in 1976. Several other examples of safety-related and offsite power-related breakers not being maintained since the 1970s were cited by the NRC as a violation.

Also at Dresden, the NRC noted that the emergency diesel generator excitation field breakers and the Reactor Protection System breakers were not included in the PM program. The NRC described in detail deficiencies in the PM procedure for 4160 VAC metal-clad switchgear at the Hatch plant.

Other negative PM practices included the failure to mitigate the effects of corrosion of a 4160 VAC bus connecting a transformer to bus switchgear at Prairie Island, which resulted in severe overheating of the lower bus bars. The NRC cited a violation because a nonconformance report had not been issued.

At Palo Verde, the NRC expressed concern over the availability of replacement reactor trip breakers or parts. Also, at Indian Point 2, the NRC expressed concern that several breakers were left uncovered long after their removal from the cubicles, which was contrary to Westinghouse recommendations and to the utility's procedures.

Examples of procedural deficiencies were noted at other plants, such as at Fitzpatrick, where procedures for one type of I&C relay were applied to another type as well, and also at H.B. Robinson, where a very simple checklist was extensively used for PM of 4160 VAC switchgear.

In the area of predictive maintenance and condition monitoring, the NRC cited deficiencies, such as those at LaSalle, where an EDG output breaker did not close in the required 13 seconds, and the cause was attributed to worn parts. The utility did not inspect the other EDGs and the HPCS EDG output breakers.

Several plants had no program for testing molded-case circuit breakers. Also, several plants were noted for failures of Siemens Allis 345 kV switchyard type breakers, which affect availability of offsite power.

Finally, in failure trending and root cause analysis, some plants were cited for failing to respond to trends noted in safety-related switchgear and for inadequate root cause analysis. The latter pertained to Dresden, where the root cause analysis for a failure of a LPCI pump motor breaker did not identify inadequate maintenance frequency as a root cause, and also no analysis had been performed after an Isolation Condenser Makeup MOV failed.

To summarize, while the NRC cited examples of good maintenance practices for electrical components, several examples of comparatively serious maintenance deficiencies were noted for safety-related and important to safety, i.e., offsite power-related, electrical components. As with other systems and components, it appears that there was significant room for improvement in the maintenance practices for electrical components at several plants.

4.2.3 Motor-Operated Valves (MOVs)

Motor-operated valves (MOVs) are used extensively in nuclear power plants in safety-related and balance-of-plant systems. The most commonly used types of MOVs are gate, globe, and butterfly valves. Failures of MOVs have resulted in significant maintenance efforts and, on occasion, have compromised the operational readiness of critical safety-related systems. Several diagnostic monitoring systems have been developed specifically for detecting MOV aging and service wear effects (degradation), failures, and switch setting problems.

4.2.3.1 Aging Insights

MOVs fail to perform in five ways:

- Failure to open
- Failure to close
- Plugged (limited or no flow through a normally open valve)
- Reverse (internal) leakage
- External leakage

Several MOV sites are susceptible to aging-related degradation. These sites and the corresponding aging mechanisms are:

- Motor Operator Gearbox Assembly: Wear or distortion of gears and shafts; fastener loosening; wear of stem nuts; loosening of stem lock nuts; change of spring pack response; wear of drive sleeves, clutch mechanisms, seals; wear and corrosion of bearings; and degradation and hardening of lubricants.

- Motor Operator Switches: Pitting and corrosion of contacts; wear of gears and cams; breakdown of insulation (electrical); loosening of fasteners; and hardening of grease.

- Electric Motor Assembly: Wear and corrosion of bearings; and insulation breakdown (electrical).

- Valve: Wear and corrosion of obturators (disc, plug, ball, gate), obturator guides, valve seats; wear and distortion of valve stems, and stem packing; deterioration of bonnet seals; erosion and corrosion of valve body; loosening of fasteners.

MOVs also are known to be adversely affected by inappropriate maintenance, such as incorrect torque of stem packing, incorrect switch settings (torque switch, limit switch, torque bypass switch), insufficient or excessive lubrication, incorrectly installed spring pack (e.g., incorrect pre-load, gap) and others.

MTI Reports

Activities associated with MOV problems are extensive, specifically in the areas of assuring the operational readiness of safety-related valves. Aging-related problems include corrosion of body parts and fasteners, packing leak at the flanges, backseating of valves, worn or broken internal parts, motor burnouts, and malfunctioning torque switches. Since valves do not continuously operate, environmental conditions can cause exposed surfaces to degrade. Other age-related problems can affect the timing of valve actuation and cause water hammer in piping systems.

NPAR Study

Since 1980, numerous NRC Inspection and Enforcement (IE) Notices and Bulletins have been issued that identify MOV problems and recommend courses of action (see references). Bulletin 85-03 (issued November 1985) and its supplement (issued April 1988) recommend that utilities develop and implement a program to ensure that switch settings for MOVs in several specified safety-related systems are selected, set, and maintained so that the MOVs will be capable of operating under design-basis conditions for the life of the plant. In June 1989, the NRC issued Generic Letter (GL) 89-10 "Safety-Related Motor-Operated Valve Testing and Surveillance," which supersedes the recommendations in Bulletin 85-03 and its supplement. GL 89-10 extends the scope of Bulletin 85-03 to include all safety-related MOVs as well as all position-changeable MOVs in safety-related systems. Table 4.1 lists from GL 89-10 33 common MOV misadjustments, and degraded conditions discovered by utilities from their experiences, including their efforts to comply with Bulletin 85-03.[99]

4.2.3.2 Managing Aging

Managing aging in MOVs is a significant concern for utilities. Most of their efforts concentrate on a good PM program and surveillance testing to assure operability. Safety-related MOVs are subjected to periodic stroke testing.

Preventive Maintenance: At each refueling outage, plants perform the PM on MOVs, which includes cleaning electrical components, lubricating moving parts and checking their condition, cleaning and lubricating the valve gear box, operating torque switches, and meggering the motor insulation. In several cases, periodic overhaul programs include replacing worn parts, lubricating the assembly, and testing the equipment. In one plant, lubricants recommended by the manufacturer (EXXON Nebula EP-0 and EP-1) were mixed with another lubricant (lithium-based Mobil Mobilux EP-0) in violation of EQ requirements.

Predictive Maintenance/Condition Monitoring/PMT: To assure the operability of MOVs, plants were noted as using MOVATS (current signature analysis), VOTES, valve stroke timing, and valve leak testing and colored photographs of internal parts. More recently developed methods include the motor current signature analysis (MCSA) method by Oak Ridge National Laboratory.[45]

Trending/RCA/PRA: Very few cases were reported of any activity in these areas.

NPAR Study

Disassembly and Inspection: The condition of valves and motor operators can be adequately determined by disassembly and inspection; however, the difficulties encountered are, for example, scheduling additional maintenance work during already busy outages and accounting for additional radiation exposure to maintenance personnel. Thus, several non-intrusive MOV diagnostic techniques were developed.

Available Monitoring Methods: The issuance of Bulletin 85-03, its supplement, and GL 89-10 has accelerated the development and commercialization of MOV monitoring

Table 4.1. Summary of Common Motor-Operated Valve Deficiencies, Misadjustments, and Degraded Conditions (from NRC Generic Letter 89-10)

1. Incorrect torque switch bypass setting	19. Misadjustment or failure of handwheel de-clutch mechanism
2. Incorrect torque switch setting	20. Relay problems (incorrect relays, dirt in relays, deteriorated relays, miswired relays)
3. Unbalanced torque switch	21. Incorrect thermal overload switch settings
4. Spring pack gap or incorrect spring peak preload	22. Worn or broken bearings
5. Incorrect stem packing tightness	23. Broken or cracked limit switch and torque switch components
6. Excessive inertia	24. Missing or modified torque switch limiter plate
7. Loose or tight stem-nut locknut	25. Improperly sized actuators
8. Incorrect limit switch settings	26. Hydraulic lockup
9. Stem wear	27. Incorrect metallic materials for gears, keys, bolts, shafts, etc.
10. Bent or broken stem	28. Degraded voltage (within design basics)
11. Worn or broken gears	29. Defective motor control logic
12. Grease problems (hardening, migration into spring pack, lack of grease, excessive grease, contamination, non-specified grease)	30. Excessive seating or backseating force application
13. Motor insulation or rotor degradation	31. Incorrect reassembly or adjustment after maintenance and/or testing
14. Incorrect wire size or degraded wiring	32. Unauthorized modifications or adjustments
15. Disk/seat binding (includes thermal binding)	33. Torque switch or limit switch binding
16. Water in internal parts or deterioration therefrom	
17. Motor undersized (for degraded voltage conditions or other conditions)	
18. Incorrect valve position indication	

systems. Several of these systems have recently been modified to provide specific capabilities needed to resolve GL 89-10.

MOV monitoring systems operate by making measurements of one or more MOV parameters and providing graphical displays (signatures) for manual and/or automated analyses. These signatures provide detailed quantitative information related to the condition of the motor, the motor operator, and the valve across a wide range of levels, including:

- mean values
- gross variations during a valve stroke
- short-time duration events (transients)
- periodic events

switches properly; however, they also provide information useful in assessing MOV aging and service wear. The sensitivity and selectivity available from these systems provide the capability to identify both the type and location of MOV problems, so that corrective actions can be carried out quickly and efficiently.

These systems generally monitor one or more of the following parameters:

- Valve stem position, torque, and thrust,
- Spring pack displacement
- Time of actuation of all control switches
- Motor current, voltage, and power
- Actuator vibration
- Actuator output torque

While many of the commercial MOV diagnostic systems monitor similar parameters (e.g., motor current, spring pack displacement), they use different transducers and signal conditioning equipment and provide varying levels of signature analysis (interpretation).

Only one MOV measurable parameter, motor current, is monitored by all commercial systems because it may be monitored remotely and nonintrusively. Motor current provides much information related to the condition of the motor, operator, and valve (although the level of information extracted from MOV motor current signals varies from system to system).

Valve stem thrust also is commonly monitored. Most systems use sensors that either monitor stem thrust (stem strain) directly or monitor the reaction forces in other structures (e.g., yoke, bolts). Monitoring stem thrust using one of these techniques is generally more accurate than an indirect method, such as deriving stem thrust from other measurements, because the relationship between stem thrust and other measurable parameters (such as spring pack displacement, motor current) can vary over time due to such changes as lubrication and gear mesh friction.

Because each MOV measurable parameter provides different (and complementary) information, the simultaneous monitoring of more than one of these parameters can give additional diagnostic details unavailable from any one measurement. For example, an unusually high running current may indicate increased running loads, although the precise source of the increase may be difficult to determine from motor current measurements alone. A simultaneously observed increase in stem thrust would suggest that the increase in running load was due to the valve (e.g., from increased packing tightness or from increased rubbing within the valve) rather than from within the motor operator. Conversely, if the levels of stem thrust are normal, increased friction from gears and bearings within the motor operator may be the cause. In that regard, the MOV diagnostics provided by these commercial systems are strongly based on concurrent analyses of several signatures.

These systems can be used efficiently to respond to most of the deficiencies, misadjustments, and degraded conditions listed in GL 89-10. The diagnostic accuracy of these systems, however, are all dependent (in varying degrees) on the skill of the person using the system. It is likely that a few of the deficient conditions listed in GL 89-10 will be detected only by on-site inspections (in some cases, involving disassembly). Such conditions include: grease problems, water in internal parts, incorrect valve position indication, broken or cracked switch components, and incorrect metallic materials, except in those cases where these deficiencies adversely affect one or more of the parameters monitored by these systems.

The MOV monitoring systems should be useful for resolving MOV issues that concern the NRC and the nuclear industry. In the last few years, there has been a dramatic increase in the number of systems available and in their capabilities. With their continued use and development, the ability to identify and quantify MOV aging and the effect of service wear will improve. These systems not only give the utilities a means for determining MOV operability, but offer the tools necessary for carrying out predictive maintenance.

4.2.3.3 Conclusions for Motor-Operated Valves

According to the MTI reports, the NRC paid a great deal of attention to utility maintenance practices for MOVs, particularly focusing on the responses to Bulletin 85-03 and Generic Letter 89-10. Some significant insights on aging could be gleaned from the MTI reports.

Thus, as noted previously for the AFW system in Appendix E, Section 1.1, at St. Lucie, following a manual reactor trip, both AFW system MOVs for the discharge side of the motor-driven pumps could not be repositioned because in one case, the stem and nut were galled and seized together, and in the other case, because the drive pinion gear on the limit switch had worn to the point that it did not mesh with the drive-sleeve bevel gear.

At both LaSalle and Prairie Island, the NRC cited violations for failure to promptly respond to a 10 CFR 21 notification by Limitorque about common mode failure of melamine MOV torque switches. The cause of the failure was post-mold shrinkage, affected by temperature and age.

At Fermi, the utility concluded that the practice of "power" or coast-in backseating was only potentially harmful to large, fast-acting valves.

Several plants were cited as having good reliability-centered maintenance for MOVs. At San Onofre, the implementation of a PM program for MOVs and a diagnostic testing program had significantly reduced MOV failures since 1987. At Zion and Dresden, the MOV overhaul programs included a complete inspection; resistance testing of the motor; lubrication of the main gear case, the limit switch compartment and the valve stem; and proper setting of the torque and limit switches. At Zion, there had been a 40% reduction in MOV failures in one year as a result of the program.

Good examples of MOV preventive maintenance practices also were cited at Maine Yankee, Waterford, H.B. Robinson, and Fermi. At Waterford, the scope of the MOV program, which the NRC considered to be significantly above the industry norm, included both safety-related and BOP valves.

The NRC focused extensively on predictive maintenance and condition monitoring of MOVs. Almost every plant used some condition monitoring technique, such as MOVATS, for their MOVs. At Indian Point 3, engineering personnel took colored photographs of many MOV internals during the previous outage, showing whether the operators had two- or four-limit switch rotors, an approved torque switch, and correct jumper wires. Some plants also were using the VOTES technique, which indirectly measures stem thrust by measuring yoke strain through the entire valve stroke.

The same techniques of MOVATS and VOTES were used for post-maintenance testing at several plants. A few examples of positive failure trending programs and root cause analyses involving MOVs also were cited.

In addition to the violations cited for slowness to respond to MOV aging concerns regarding common-mode failure of melamine torque switches, other negative MOV maintenance practices were noted. At South Texas, the prioritization scheme for MOV maintenance emphasized personnel availability rather than technical justification for deferring PM. The utility also failed to recognize the connection between PM deferrals for MOVs and an increased rate of MOV failure to function upon demand.

Examples of poor MOV maintenance practices were as follows. At Waterford, three environmentally-qualified, safety-related MOVs inside the reactor building (containment) were lubricated with a mixture of two different types of greases, contrary to the instructions in the plant lubrication manual, which specified only one type of grease; this was cited by the NRC as a violation. Also, at South Texas, the NRC noted that the limit switch/torque switch compartment of an EQ MOV was not sealed because the cover gasket had been totally compressed and hardened. Supplemental holes had been punched in the gasket so it would fit in the existing bolt pattern.

The most common deficiency in predictive maintenance and condition monitoring was not applying diagnostic techniques, such as MOVATS and VOTES, to an adequate sample of MOVs. Specifically, at several plants, MOVATS testing was not applied to any safety-related valves not covered by Bulletin 85-03, nor to any BOP valves. Also, inadequate monitoring was noted at River Bend, where contrary to the requirements for prompt inspection and retorquing of the yoke and bonnet bolts on an RHR test return MOV, a run-out check with dial indicators to check for bent stem at the time of stroking was not performed; this was cited as a violation.

The most common deficiency in PMT was inadequate specification of test requirements and/or acceptance criteria. In some cases, PMT applicable to the scope of work was not performed.

An adverse trend of MOV failures involving Limitorque operators and Masoneilan valves was noted at Sequoyah. In over 9 years, 284 Masoneilan valves with stem rotation problems were identified.

Finally, the NRC cited the failure of several BWRs to conduct root cause analysis following MOV failures. The failures involved the HPCI, Isolation Condenser Makeup, and RHR systems.

Much progress was being made in the area of MOV maintenance at the time of the MTIs, generally spurred by the need to respond to NRC Bulletin 85-03, and subsequently, to NRC Generic Letter 89-10. Diagnostic testing of MOVs was proceeding both for predictive maintenance and post-maintenance testing. However, some poor maintenance practices were noted, and failures to conduct root cause analysis for some important MOV failures detracted from the overall positive outlook.

4.2.4 Check Valves

The function of a check valve is simply to open to permit flow in one direction and to close to prevent flow in the other direction. Most check valves are self-actuating, that is, they require no external mechanical or electrical signal to either open or close. Thus, most check valves have no capability to be actuated other than by changing the direction of flow through the valve. Several types of check valves are commonly used, such as the swing-check, piston-lift, ball, stop-check, tilting-disc, and duo-check designs. These valves are used extensively in nuclear power plant safety systems and balance-of-plant systems. Since 1980, numerous NRC Inspection and Enforcement (IE) Notices and Bulletins have been issued that identify check valve problems and recommend courses of action. Check valve failures have resulted in significant maintenance efforts and, on occasion, have resulted in water hammer, overpressurization of low-pressure systems, and damage to flow system components. Several diagnostic monitoring methods are now available for detecting the aging of check valves and service wear efforts (degradation), check valve failures, and undesirable operating modes.

4.2.4.1 Aging Insights

Check valves fail to function in five ways:

- Failure to open
- Failure to close
- Plugged (limited or no flow through a normally open valve)
- Reverse (internal) leakage
- External leakage

Several check valve sites are susceptible to aging-related degradation. These sites and the corresponding aging mechanisms are:

- Body Assembly: Erosion, corrosion and rupture of valve bodies; loosening and breakage of fasteners
- Internals: Wear, erosion and corrosion of hinge pins, seats and discs; wear and fracture of hinge pins and arms; loosening, overtightening and breakage of disc nuts; presence of foreign material
- Seals: Deterioration of cap gaskets

MTI Reports

Mechanisms of age-related degradation include pitting, erosion/corrosion of valve body, loose springs, damaged rubber seat, leaking valves, stuck open disc, and blockage of flow path by accumulation of boric acid. Corrosion and separation of the hinge pins, hinge arms, discs, and disc nut pins resulting from the turbulent flow of fluid have caused check valves to fail prematurely.

NPAR Study

Failures of check valves have been attributed largely to severe degradation of internal parts (e.g., hinge pins, hinge arms, discs, and disc nut pins) resulting from instability (flutter) of check valve discs under normal plant operating conditions. The instability of check valves may be a result of misapplication (using oversized valves) and exacerbated by low flow conditions and/or upstream flow disturbances.

The nuclear industry itself also recommends that nuclear power plants establish a preventive maintenance program to ensure the reliability of check valves. The maintenance program should include periodic testing, surveillance monitoring, and/or disassembly and inspection.

4.2.4.2 Managing Aging

Because check valves contain simple passive components, very little maintenance can be done to mitigate aging effects. Most activities are done to verify operability. Full-flow and back-flow testing of check valves have been specified by the NRC in Generic Letter 89-04.[26,27]

MTI Reports

Among the problems with check valves were leakage from instrument air accumulators and stuck-open flappers.

Preventive Maintenance: The activities included in the PM program are periodic inspection, acoustic monitoring, leak testing, and stroke testing of the valves. Because of their passive nature, no structured PM program was noted that is applicable to all check valves.

Predictive Maintenance/Condition Monitoring/PMT/Trending/RCA/PRA: In general, only limited activity was occurring in these areas. Trial use of techniques for acoustic emission monitoring had begun at some plants. Utilities had responded in particular to NRC Information Notice 86-01[46].

NPAR Study

Disassembly and Inspection: Utilities periodically disassemble and inspect to respond to NRC recommendations. While disassembly and inspection provides adequate information on valve condition, there are several disadvantages, including, for example, the need to schedule additional maintenance work during already busy outages, additional radiation exposure to maintenance personnel, and the possibility that errors in valve reassembly can go undetected (for valves that cannot be tested with flow). Thus, several non-intrusive check valve diagnostic techniques have been developed.

Monitoring Methods: The monitoring methods for check valves can provide diagnostic information that is useful in determining the condition of the valve (e.g., integrity of internal parts), and its operating state (stable or unstable). These methods use different transducers and principles of operation; hence, they provide different capabilities and suffer from different limitations. Monitoring methods are summarized in Table 4.2, along with selected diagnostic capabilities and limitations.

None of the methods examined can, by themselves, monitor the position and motion of valve internals and valve leakage; however, the combination of acoustic emission with either of the other methods yields a monitoring system that succeeds in determining vital operational information on check valves. Table 4.2 summarizes some of the methods available for monitoring check valves.

4.2.4.3 Conclusions for Check Valves

During the MTIs, much attention was paid to the utility's maintenance of check valves, in light of NRC Information Notice 86-01 concerning failures of check valves. The NRC also had issued Generic Letter 89-04, which provided guidance on developing acceptable inservice testing programs.

In the MTI reports reviewed, there were only a few specific insights on aging. At D.C. Cook, 4 out of 29 check valves showed minor pitting, one showed signs of erosion and corrosion, and one with a centerline split disc had a loose spring, an eroded stem hinge, and a damaged rubber seat insert. At Limerick, 10 to 20 percent of the check valves of the Essential Service Water system had restricted disc travel caused by the buildup of corrosion.

In response to the NRC notices, some plants had intensified their check valve maintenance programs. However, at Sequoyah, a Main Steam swing check valve was inspected and showed degradation, and two of the remaining three valves required replacement of parts. Instead, the valves were repaired by weld buildup, and subsequently failed, mainly from large weld-induced stresses.

Numerous examples of positive condition monitoring activities in response to the NRC notices were cited by the NRC. For example, at Calvert Cliffs, the utility was actively involved in resolving industry and plant concerns about check valves. The Nuclear Industry Check (NIC) Valve Group was evaluating non-intrusive techniques for testing. Out of 400 check valves at both Calvert Cliffs units, 30 were to be acoustically monitored in 1991. Similarly, at River Bend, an acoustic monitoring program was being developed for check valves, and the utility was working with EPRI and other utilities to evaluate degraded performance of check valves in the laboratory using the acoustic emission monitoring (AEM) program. A few examples of positive post maintenance testing and failure trending activities also were cited.

On the negative side, poor condition monitoring practices were noted at several plants. At Fermi, the NRC cited a violation because procedural inadequacies resulted in failure to full stroke test four testable check valves in the RHR and Core Spray systems. The test actuator provided only a partial stroke. Full-flow testing was performed by other procedures. Also, in the

Table 4.2. Selected Diagnostic Capabilities and Limitations of Check Valve Monitoring Methods[1]

Method	Detects valve internal leakage	Detects internal impacts	Detects fluttering (no impacts)	Non-intrusive	Sensitivity to ambient conditions[2]	Monitors disc position throughout full range of disc travel	Works with all fluids
Acoustic emission	Yes	Yes	No	Yes	Sensitive to externally generated noise/ vibration	No	Yes
Ultrasonic inspection	No	Yes (indirectly)	Yes	Yes	Unknown	Not in all cases because of limited viewing angle of transducer	No - low density fluid (e.g., air or steam) may result in severe attentuation of signals
Internal Permanent Magnet Techniques	No	Yes (indirectly)	Yes	No - requires installation of permanent magnet inside the valve	Sensitive to nearby external magnetic fields (e.g., from motors)	Yes	Yes
External AC and DC Magnetic Techniques	No	Yes (indirectly)	Yes	Yes	DC Method - Sensitive to nearby external magnetic fields (e.g., from motors)	Yes	Yes

[1] Radiography and pressure noise analysis methods are not summarized in this table. This table does not reflect other attributes such as cost, ease of use.

[2] Temperature and radiation effects are unknown.

Standby Liquid Control System, closure of check valves was not being tested despite the requirements of the ASME Code Section XI for testing valves which are required to close to prevent reverse flow. Similar examples were cited at H.B. Robinson, where three MSIV Instrument Air accumulator check valves, required to maintain the MSIVs in the closed position, were not included in the ASME Code Section XI testing program, and at Surry, where check valves, which ensure operability of backup accumulators for air-operated valves required for safe shutdown, were not included in the IST program.

In post maintenance testing, another example of the violation cited at Fermi was the acceptance of an RHR check valve by operations personnel without a stroke test following maintenance. The valve subsequently did not stroke and had been incorrectly reassembled. Adequate instructions had not been provided.

A few deficiencies in trending failures of check valves were cited, such as at Rancho Seco, where there were incomplete or missing entries of information for NPRDS-reportable failures pertaining to Instrument Air check valves. Also, at Fitzpatrick, during a check valve inspection, when an adverse condition was found, the

Comment and Apparent Cause portions of the tracking form were left blank.

Finally, regarding root cause analysis, a violation was cited by the NRC at Rancho Seco, because a nonconformance report had not been written after debris had caused two Instrument Air check valves to fail during a special test. The problem had not been recognized for its generic implications, nor the risks of using sealing tape on threaded joints.

To summarize, the MTI reports suggest that utilities have increased their maintenance of check valves. Progress had been made, particularly in condition monitoring, with many plants implementing such programs for check valves. In a few cases, acoustic monitoring techniques were specifically mentioned. However, these programs were at an early stage of development at the time of the MTIs and so their effectiveness was unknown. Additional efforts in failure trending and root cause analysis would be beneficial as well.

5.0 GENERAL SUMMARY AND CONCLUSIONS

The NRC staff assessed the maintenance programs at every nuclear power plant site in the country. In the process, a large database was made available which, after extracting and reorganizing, could be presented in a perspective useful to those concerned with managing aging-related degradation of nuclear power plant systems and components. The information lends itself more to qualitative rather than quantitative evaluation; therefore, the focus of this report is on providing qualitative assessments of the programmatic areas, and on discussing this information for systems and components. A summary of the conclusions follows.

5.1 Programmatic Areas

5.1.1 Specific Aging Insights

While some utilities appeared to assume a proactive stance to prevent aging-related failures of both safety-related and important balance-of plant systems and components, others seemed to be taking a passive or reactive stance. Differing maintenance philosophies, financial resources, and lack of regulatory requirements have affected plant management's attention to aging concerns. It did not appear that any utility had a separate program to address the management of aging. From reviewing the 44 MTI reports, it can be concluded that, at the time of the inspections, the management of aging as a forward-looking program was in its early stages of implementation.

5.1.2 Preventive Maintenance

Degradation caused by aging can only be effectively managed if the basic preventive and corrective maintenance programs are suitably designed and implemented. All utilities have maintenance programs, many of which are well designed with noteworthy practices. For example, two plants, Clinton and Perry, implemented a 13-week "rolling" maintenance schedule in which an entire safety division of systems and components are removed simultaneously for maintenance and periodic surveillance testing. Other good practices were the initiation of Reliability Centered Maintenance programs, procedure reviews, and the development and use of computerized maintenance databases. Most weaknesses identified were in implementing these programs, including failure to complete the required maintenance promptly, failing to follow procedures, lack of engineering technical support, poor control of vendor manuals, and lack of incorporation of vendor recommendations.

5.1.3 Predictive Maintenance and Condition Monitoring

In general, the use of advanced condition monitoring techniques was in the early stages of implementation at most plants at the time of the MTIs. However, in many cases, an impressive trend of increasing use of such techniques could be seen. A good example of a utility's initiative was the MESAC or micro-electronic surveillance and calibration system designed and developed at the Braidwood station to dynamically test instrument systems. Examples were cited at two plants, where condition monitoring techniques were successfully used to identify degraded equipment, so that replacements could be scheduled rather than following an unexpected failure. The most common techniques were thermography, analysis of lube oil, and vibration monitoring of rotating equipment.

Examples of violations cited were of failures to conduct timely testing of circuit breakers, MOVs, and turbine-driven Auxiliary Feedwater pumps; also there were potential deviations from the testing and acceptance criteria of the ASME Boiler and Pressure Vessel Code Section XI.

5.1.4 Post-Maintenance Testing

Some utilities relied upon the surveillance tests (required by the Technical Specifications) to satisfy PMT requirements, particularly for I&C components. The NRC usually considered this method to be acceptable except for complex mechanical and electrical components, such as pumps and circuit breakers, where such testing was considered an operational test, rather than a specific test, which focused on the actual maintenance work performed.

Other problems noted included the lack of specific PMT requirements, lack of involvement of System Engineers in setting PMT requirements, and poor documentation of PMT results.

At least two examples of PMT-related violations were cited. While examples of well documented and implemented PMT programs were noted, it can be concluded that PMT was a weak area at many plants at the time of the MTIs.

5.1.5 Failure Trending

To successfully manage aging, detecting equipment degradation or increasing failure rates is essential. One of the tools available to maintenance management is trend analysis. The evaluation of the MTI reports revealed that most plants were deficient in some way in this area. Poor descriptions of the cause of failure of particular components was one of the most common problems inhibiting failure trending analysis. While it difficult to assess the safety significance of some negative findings, it is clear that at a substantial number of plants, a lack of commitment to monitor long-term degradation and failure histories of key components, systems, and structures makes it unlikely that the maintenance program will be effective in detecting and mitigating the effects of aging.

5.1.6 Root Cause Analysis

The NRC cited several cases of very well performed and documented cases of root cause analysis, as well as a few cases where System Engineers were involved in the process. However, more deficiencies were cited than positive examples.

There were several instances where utilities failed to take timely action to perform a root cause analysis, and thereby failed to take corrective actions. There were numerous examples of poor documentation of "As Found" conditions, as well as examples of analyses which were not sufficiently deep, or were characterized by the NRC as poor, or where the threshold for initiating analysis was too high or ill defined. Procedures sometimes had inadequate details on how to perform a root cause analysis, and system engineers were inadequately trained and not actively involved in trending and root cause analysis.

While the NRC cited several examples of thorough and detailed analyses and proper recording of the causes of failure, as with post-maintenance testing and failure trending, it can be concluded that root cause analysis was another generally weak area at the time of the MTIs.

5.1.7 Usage of Probabilistic Risk Assessment

Only a few utilities were identified as actively using PRA, of which even fewer were using it specifically in the maintenance process. Some utilities were implementing Reliability Centered Maintenance (RCM) programs for a limited number of the most important systems.

PRA was most commonly used for more higher level decision making such as scheduling system outages, justifying limiting conditions of operation (LCOs), determining the importance of implementing modifications, and prioritizing the order of implementation for those selected. Because such modeling still is in the development stages in the nuclear power industry, no mention was made in any of the 44 MTI reports of modeling of a plant PRA using time-dependent failure rates for the basic system components, which is the only way in which PRAs can be used to manage aging.

5.2 Systems and Components

5.2.1 Systems

5.2.1.1 Auxiliary Feedwater

The most prominent positive features noted pertained to condition monitoring techniques applied to the AFWS pumps, such as vibrational analysis, oil sampling, and pump differential pressure measurements.

Although the AFWS is generally considered to be one of the most important systems in a PWR, there were several serious deficiencies, such as the incident at Rancho Seco following a post-maintenance test on the governor of the AFWS steam turbine-driven pump and the overspeed trip, in which both trains of the AFWS were overpressurized beyond their design stress values.

Other examples of never testing the AFWS turbine-driven overspeed device, or of allowing scheduled tests to elapse (17 years), were noted, as well as failure to incorporate important recommendations from the vendor about leakage of the pump packing. Some specific aging-related failures of AFWS MOVs and check valves also were cited.

5.2.1.2 Feedwater Systems

At at least one plant, an Important-to-Safety category had been established, which included Feedwater pumps and control valves. At other plants, the MFW was often included in the Reliability Centered Maintenance program.

Techniques for monitoring the thinning of the pipe wall due to erosion and corrosion were applied to many different lines on the BOP side, such as extraction steam and heater drains. Rotating equipment sometimes identified as being monitored for vibration included the MFW pump turbines and the condensate pumps. Lube oil of MFW pumps also was sampled.

On the negative side, leakage from the MFW pump, either of oil or water at the seals, was the most common aging-related failure or degradation in the MFW system observed by the NRC. MFW flow control valves were sometimes noted for their high frequency of maintenance. Deficiencies were noted in the documentation of maintenance records, which were sometimes ineffective for trending and root cause analyses. The root cause analyses were sometimes superficial, citing symptoms, not causes.

5.2.1.3 High Pressure Injection Systems

Good maintenance practices were noted at some plants, such as the HPCI Maintenance Improvement Program at Dresden, which included an MOV upgrade and preventive maintenance program, and enhanced failure analysis and post-maintenance testing. Condition monitoring techniques, such as MOVATS, were applied to HPI MOVs in many cases and vibration analysis performed on HPI pumps.

On the negative side, at one plant, some IEEE standard maintenance practices for motors in the Safety Injection System were not implemented. Incorporation of vendor recommendations also was inadequate in some cases. Examples were noted where root cause analyses were either inadequately performed or not performed at all, as in the case of a HPCI MOV failure. Oil leakage was noted on HPI pumps at both BWRs and PWRs, and leakage was observed on MOVs.

Although High Pressure Injection systems are important for mitigating many accident scenarios, there were some serious maintenance-related deficiencies.

5.2.1.4 Service Water Systems

Several plants were well aware of problems in their Service Water systems caused by erosion and corrosion, and had either begun or planned to take corrective actions, such as at Salem, where the SW piping will be replaced with 6% molybdenum stainless steel piping by 1995. The SW system was included in the Reliability Centered Maintenance program at several plants. Several plants monitored vibration in the SW pumps.

Examples of poor maintenance practices were cited, such as lack of chemical treatment of an Emergency Service Water spray pond that caused piping and valves to become filled with sludge and scale. Failing to incorporate maintenance good practices recommended by industry, and also vendor recommendations were cited. Inadequately specified acceptance criteria for condition monitoring and inspecting internals of check valves, and for post-maintenance testing specifications of other components also were noted. Root cause analyses were inadequately performed in some cases for SW components.

In summary, the MTI reports showed that while there were many examples of inadequate maintenance activities for SW systems, utilities were conscious of SW as a problem system which warranted increased maintenance attention.

5.2.1.5 Instrument Air and Emergency Diesel Generator Air Start Systems and Compressors

Very significant aging-related problems were noted at Surry in the EDGAS, which were caused by moisture-induced deterioration of compressor valves and the unavailability of replacements. These problems forced replacement of the six air compressors. There was no program to monitor or control EDG starting air quality. Leakage from the Instrument Air system header was 47 CFM, which the NRC considered excessive. The drier filters of the Containment IA system had not been replaced since installation 7 years earlier, and the system could not maintain the required dew point (35°F), even under optimum conditions.

At Palisades, an emergency diesel generator could not be started because the air compressor would not operate. At ANO, there were numerous IA system parts in storage whose shelf life had expired, indicating a lack of awareness of aging of non-safety related equipment. Similar parts were in service even longer than the parts in storage. At Shearon Harris, even though the Rotary Air Compressor was now supplying 100% of station IA requirements, there were no formal preventive or corrective maintenance, operations, or surveillance procedures. At H.B. Robinson, important vendor recommendations concerning the wear rate for the Teflon wear and seal rings of the IA compressors had not been incorporated into the PM procedure. At St. Lucie, only major non-safety related equipment such as IA compressors were subject to PMT, and the instructions and acceptance criteria were vague.

On the positive side, examples of rigorous and thorough root cause analyses were cited, such as at Cooper, following the rupture of an IA drier post-filter housing which ultimately caused a reactor trip, and at Waterford, where there was low flow of the IA and Station Air compressors and premature degradation of the compressor.

The IA and EDGAS systems were inadequately maintained at several plants at the time of the MTIs.

5.2.2 Components

5.2.2.1 Emergency Diesel Generators

Some notable PM practices concerning EDGs were identified, such as at Indian Point 2, where, based on very positive results of a 12-year PM on one of the EDGs, a modified 12-year PM was performed on the remaining two EDGs, even though they were not due for the 12-year PM. At Indian Point 3, a Component Engineer was assigned as the head of a team of engineers to conduct PM on the EDGs. The EDGs were one of the components frequently selected for analysis of [illegible].

On the negative side, at Palisades, a flow switch had been incorrectly bypassed for at least 8 months. Under certain conditions, upon starting, the engine could be stressed causing accelerated aging and, possibly, harder starts.

Several plants were cited for violations concerning poor PM practices, including the lack of full thread engagement for the terminal lugs of an EDG excitation panel, the lack of a QC inspection of critical reassembly steps and clearance measurements of an EDG at Cooper, and the omission from the PM program of the EDG excitation field breakers at Dresden. There were examples of failure to incorporate vendor recommendations.

In root cause analysis, violations were cited for failing to take aggressive actions to resolve the problems with the EDG jacket cooling water systems at Palo Verde and Duane Arnold.

Although emergency diesel generators are critically important for the loss of offsite power conditions, there were several deficiencies at some plants which the NRC identified as violations. Increased attention to EDG maintenance is warranted at several plants, based upon the MTI reports.

5.2.2.2 Electrical Components: Breakers, Switchgear, Relays and Motor Control Centers (MCCs)

The NRC noted some examples of good responsiveness to concerns about aging of electrical equipment, such as at Sequoyah where PM procedures had been revised to inspect for cracks and to replace main toggle link pins in 6900 VAC circuit breakers. The pins had a significant failure rate early in plant life.

Good preventive maintenance practices were noted at plants such as at Shearon Harris, where approximately one-half of the switchgear received PM at every refueling outage, and at Waterford, where reactor trip breakers were refurbished every five years in response to the manufacturer's warning that the grease may solidify.

On the negative side, some examples of slow response to aging concerns and the neglect of circuit breaker maintenance were identified, as at Duane Arnold where a violation was cited for an inadequate response to a vendor's 1979 service advice letter about premature wear of Tef-LOC Teflon-coated fiberglass sleeve bearings in 4160 VAC breakers. The components affected included the RHR and Reactor Recirculation pumps. At Dresden, violations were cited because breakers for two of the Containment Cooling Service Water pumps had not been overhauled since 1976. Other safety-related breakers had not been maintained since the 1970s. [illegible] at Dresden, the emergency diesel generator excitation field breakers and the Reactor Protection System breakers were not included in the PM program. At Palo Verde, the NRC expressed concern over the availability of spare reactor trip breakers or parts.

Procedural deficiencies also were noted, such as at H.B. Robinson, where a very simple checklist was used to conduct PM of 4160 VAC switchgear. An example of poor predictive maintenance and condition monitoring was cited at LaSalle, where the output breakers of the other EDGs and the HPCS EDG were not inspected, following failure of one EDG output breaker to close in the required 13 seconds. Several plants had no program to test molded case circuit breakers.

Some plants were cited for failing to respond to trends noted in safety-related switchgear, and also for inadequate root cause analysis: an example of the latter was the failure of an Isolation Condenser Makeup MOV at Dresden. At several plants, 345 kV switchyard type breakers, which affect availability of offsite power, had failed.

While the NRC cited examples of good maintenance practices for electrical components, they also found several examples of comparatively serious maintenance deficiencies for safety-related and important to safety, i.e., offsite power-related, electrical components. Increased attention to maintenance practices for electrical components may be warranted at several plants.

5.2.2.3 Motor Operated Valves

The NRC paid a great deal of attention to utility maintenance practices for MOVs, particularly focusing on the responses to Bulletin 85-03 and Generic Letter 89-10.

A specific example of aging of MOV component parts was cited by the NRC at St. Lucie where, following a manual reactor trip, both AFWS discharge MOVs for the motor-driven pumps could not be repositioned; in one case, because the stem and nut were galled and seized together, and in the other case, because the pinion gear of the limit switch drive had worn to the point that it was not meshed with the drive sleeve bevel gear. Both LaSalle and Prairie Island were cited for violations because of failure to promptly respond to a 10 CFR 21 notification about common mode failure of melamine MOV torque switches caused by post-mold shrinkage affected by temperature and age.

At San Onofre, Dresden, and Zion, PM programs specifically aimed at MOV failure rates. These programs included complete inspection, motor resistance testing, lubrication of the main gear case, the limit switch compartment, and the valve stem, and proper setting of torque and limit switches.

Almost every plant applied some form of condition monitoring technique, such as MOVATS or VOTES, to their MOVs. The most common deficiency was not applying such techniques to an adequate sample of MOVs. MOVATS testing was often not applied to any safety-related MOVs not covered by Bulletin 85-03 nor to any BOP valves.

Poor MOV maintenance practices included mixing two different greases, which was a violation at Waterford. At South Texas, the MOV maintenance schedule appeared to be based on the availability of personnel rather than technical justification for deferring PM deferral, and the connection between PM deferral and increased failures of MOVs to operate on demand was not recognized.

Post-maintenance testing and/or acceptance criteria were sometimes inadequately specified or the testing was not applicable to the scope of work performed. The NRC noted failures to conduct root cause analysis following MOV failures at several BWRs, and which involved the HPCI, Isolation Condenser Makeup, and RHR systems.

Much progress was being made in MOV maintenance, which was generally spurred by the need to respond to NRC Bulletin 85-03, and subsequently to NRC Generic Letter 89-10. Diagnostic testing of MOVs was proceeding both for predictive and post-maintenance testing. However, some poor maintenance practices were noted, and failures to conduct root cause analyses for some important MOV failures detracted from the overall positive outlook.

5.2.2.4 Check Valves

The NRC also focused on utility maintenance of check valves. The utilities were responding to NRC Information Notice 86-01 concerning failures of check valves. At Limerick, 10-20% of Essential Service Water check valves had restricted disc travel due to buildup of corrosion. In response, some plants had intensified their maintenance programs.

Numerous examples of positive condition monitoring techniques were evident, such as at Calvert Cliffs, where the utility was actively involved in resolving industry and plant concerns about check valves. The Nuclear Industry Check (NIC) Valve Group was evaluating nonintrusive testing techniques. Out of 400 check valves at both units, 30 were to receive acoustic emission monitoring in 1991. River Bend also was working with EPRI on an acoustic emission monitoring program.

Several plants had poor monitoring practices. At Fermi, a violation was cited for procedural inadequacies, which resulted in a failure to full-stroke test four testable check valves in the RHR and Core Spray systems. In the Standby Liquid Control System, closure of check valves was not being tested, despite the requirements of the ASME Code Section XI for testing of valves which prevent reverse flow. Other examples involving the failure to test MSIV Instrument Air Accumulator check valves and other safe shutdown required valves were noted at H.B. Robinson and at Surry.

Poor post-maintenance testing practices, which the NRC deemed a violation, were noted at Fermi where operations personnel accepted an RHR check valve without a stroke test following maintenance. The valve subsequently did not stroke, and had been incorrectly reassembled, because of inadequate instructions.

Deficiencies in failure trending were noted at some plants such as at Fitzpatrick, when an adverse condition was found during the inspection of check valves; the Comment and Apparent Cause portions of the tracking form were left blank. At Rancho Seco, the NRC cited as a violation the failure to recognize the risk significance of using sealing tape on threaded joints, which resulted when two IA check valves failed during a special test due to debris.

To summarize, the utilities have increased their attention to check valve maintenance. Progress has been made, particularly in condition monitoring, with many plants implementing such programs for check valves. In a few cases, acoustic monitoring techniques were specifically mentioned. However, these programs were at an early stage of development, and so their effectiveness is unknown. Additional efforts in failure trending and root cause analysis would be beneficial.

5.3 Comments Concerning the NRC Maintenance Rule

The new NRC Maintenance Rule 10CFR50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," was approved and issued on June 28, 1991, and has a five-year implementation period. This rule is performance-based and requires an assessment of the effectiveness of a plant's maintenance program. Condition monitoring and the use of industry-wide data are required for safety-related SSCs as well as certain nonsafety-related SSCs. Regulatory Guide 1.160 for monitoring the effectiveness of maintenance has since been issued. This guide in turn endorses guidance developed by the industry as provided in NUMARC 93-01.

5.4 Final Comments

In many ways, maintenance in a nuclear power plant is really no different from maintenance at any industrial facility, as exemplified by excerpts from a recent article in Mechanical Engineering magazine:[47]

Maintenance programs enable users to institute both preventive and predictive procedures. Preventive maintenance seeks to forestall failures by keeping equipment in good condition. To this end, parts may be lubricated or replaced at regularly scheduled intervals to ensure that the unit continues to run smoothly. Predictive maintenance works on the assumption that breakdowns will occur even with regular replacement of parts. Therefore, actual operating conditions - including, for example, temperature, vibration, shaft alignment, and oil pressure - are continuously monitored and analyzed to catch problems before they prove fatal. In this way, it can be determined when equipment overhaul or replacement is needed.

Brian Feeley, marketing manager at Ecta, stressed the importance of working with an in-house expert when developing a list of necessary preventive-maintenance tasks at a factory. 'It is the pipefitter, the electrician, the foreman - or sometimes, the operator - who will know the type of test needed to keep the equipment functioning,' he said.

Emonitor is used at the Quantum Chemical Corp. (Cincinnati) petrochemical plant in Morris, Ill. The plant manufactures a variety of plastics. Maintenance technicians using handheld computers take over 175,000 vibration measurements on critical equipment in the plant annually.... Vibration data gathered by plant technicians have helped prevent expensive machine failures. For example, a loose tie rod on a compressor was found by vibration analysis before it could damage the compressor. On another occasion, vibration of a gear box that runs an agitator pinpointed two worn bearings and gears that were replaced by Quantum technicians. Ordinarily, the gear box is shipped out of the plant for repair and the entire gear train is replaced, a much more expensive and time-consuming procedure.

According to Clemmons, maintenance software is a valuable tool. 'For example, we perform bearing dissections to find out why bearings wear out and store the information on the computer,' he said. Instead of having to rely on the bearing manufacturer for information on part failure, Clemmons and his colleagues are able to draw upon their own findings in the field.

To better trace potential problems, the next stage in the development of maintenance software will focus on coordinating equipment data. 'The maintenance department of the future will have a completely integrated maintenance database, including infrared thermography, ultrasonic testing, and metal thickness testing,' said Entek president Tony Shipley. User-friendliness will also be a key concern, because the programs must remain simple enough for novice technicians to use.

The relevance of these comments to the maintenance of nuclear power plants is very clear. Improvements in preventive and predictive maintenance programs, including failure trending and root cause analysis, together with the development of an integrated maintenance database, will significantly improve the safety of nuclear power plant operations.

In fact, according to a recent article in the EPRI Journal,[48] a new strategy to incorporate effective measures to address age-related degradation of safety systems and equipment covered under federal regulations that govern the renewal of licenses is being implemented at many of the 111 nuclear power plants, as several reactors approach the expiration of their current operating license.

The concept, known either as life-cycle management (LCM), life optimization, or aging management, ranges from a philosophy to a methodology, but as many as 20 plants have established programs and begun planning. LCM seeks to coordinate the work of diverse, ongoing plant activities within a planning framework that extends for five to ten scheduled outages, or more, into the future. LCM involves improving and making greater use of the extensive computer databases that contain details of plant configurations, operating histories, and maintenance and performance records of systems, structures, and components. Also, it extends the application of systematic screening and evaluation, preventive maintenance prioritization and strategic scheduling, condition monitoring, and collection and analysis of wear and repair data to all SSCs that are important to plant safety, reliability, and economics.

The article quotes Gerald Neils, an executive engineer at Northern States Power, who ways that LCM "...is going a little further than required by the regulators to turn over the rocks to see if there are any worms under them...(LCM) requires a change in attitude and an acknowledgement that most of the existing maintenance programs - such as check-valve maintenance, erosion-corrosion pipewall thinning measurements, motor-operated valve maintenance, and others that the NRC compels us to do - we should perhaps be doing more thoroughly than the NRC insists, as part of a long-term maintenance strategy." According to Neils, LCM will evolve to a form of reliability-centered maintenance in the nuclear industry, the approach that was originally developed in the aircraft industry and which relies on reviewing failure data to set maintenance and replacement frequency.

Another example of the type of thinking taking place in the nuclear industry, also from the EPRI article, was expressed by Don Eggett, program manager for nuclear plant aging and license renewal at Commonwealth Edison. He states that "the activities that will need to be carried out to meet the requirements of 10CFR50.65 - the maintenance rule - will aid in facilitating the plans we're developing and implementing with LCM or aging management. They just can't function separately. Any existing, effective maintenance program that manages age-related degradation should see only minimal impact from the requirements of the maintenance rule. This would be true of any utility. We believe the rule will just make our company's aging - management program that much stronger."

In summary, we believe that by using many positive features of maintenance programs highlighted in this report, and by improving the management of aging, the effectiveness of maintenance programs would be enhanced, and with that, further improvement in the level of safety would be achieved.

6.0 REFERENCES

1. U.S. NRC Inspection Report Nos. 50-321/89-02 and 50-366/89-02, Licensee: Georgia Power Company, Facility: Hatch 1 and 2, dated May 22, 1989.

2. Vol. 53, Federal Register, Issue No. 56, "Final Commission Policy Statement on Maintenance of Nuclear Power Plants," U.S. NRC, Pages 9430-9431, March 23, 1988.

3. U.S. NRC, "Maintenance Inspection Guidance," Temporary Instruction 2515/97, November 3, 1988.

4. U.S. NRC, "Maintenance Programs for Nuclear Power Plants," Draft Regulatory Guide, DG-1001, August 1, 1989.

5. Gody, A.T., McKenna, E., Hart, K.R., U.S. NRC, "Maintenance Team Inspections," Transactions of the American Nuclear Society, Volume 61, pp. 319-320, Nashville, TN, June 10-14, 1990.

6. U.S. NRC, "Staff Evaluation and Recommendation on Maintenance Rulemaking," SECY-91-110, April 26, 1991.

7. Vol. 56, Federal Register, Issue No. 132, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants", U.S. NRC, Pages 31306-31324, July 10, 1991.

8. U.S. NRC, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Regulatory Guide 1.160, June 1993.

9. Nuclear Management and Resources Council, Inc. "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," NUMARC 93-01, Washington, DC. May 1993. Available from U.S. NRC Public Documents Room.

10. Fresco, A., Gunther, W., "Evaluation of NRC Maintenance Team Inspection Reports for Managing Aging," Proceedings of the International Meeting on Nuclear Power Plant and Facility Maintenance, American Nuclear Society, Volume 2, pp. 576-584, Salt Lake City, UT, April 7-10, 1991.

11. Electric Power Research Institute, "Nuclear Power Plant Common Aging Terminology," Palo Alto, CA,EPRI Report TR-100844, November 1992..

12. **askSam Version 5.0a**, Seaside Software, Inc., DBA askSam Systems, Perry, FL, copyright 1985-1991.

13. Gunther, W., Subudhi, M., Taylor, J.H., "Operating Experience and Aging-Seismic Assessment of Battery Changers and Inventors," NUREG/CR-4564, BNL-NUREG-51971, p. 2-21, June 1986.

14. American Society of Mechanical Engineers, ASME Boiler and Pressure Vessel Code, Section XI, Subsections IWP and IWV, code in effect.

15. Subudhi, M., MacDougall E., Kochis, S., Wilhelm, W., and Lee, B.S., "Age-Related Degradation of Westinghouse 480-Volt Circuit Breaker: Mechanical Cycling of a DS-416 Breaker - Test Results," NUREG/CR-5280, BNL-NUREG-52178, Vol. 2, November 1990.

16. Nicholas, Jr., J.R., Young, R.K., "Status of Condition Monitoring and Predictive Analysis Methods and Systems in United States and Canadian Utilities as of Early 1991," Proceedings of the International Meeting on Nuclear Power Plant and Facility Maintenance, American Nuclear Society, Volume 2, pp. 278-292, Salt Lake City, UT, April 7-10, 1991.

17. Institute of Electrical and Electronics Engineers, "Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," IEEE Standard 323-83, Reaffirmed 1990.

18. Institute of Electrical and Electronics Engineers, "Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations," IEEE Standard 344-87, 1987.

19. U.S. NRC, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," IE Bulletin 85-03, November 15, 1985.

20. U.S. NRC, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," Bulletin 85-03, Supplement 1, April, 27, 1988.

21. U.S. NRC, "Safety-Related Motor-Operated Valve Testing and Surveillance, 10 CFR 50.54(f)," Generic Letter 89-10, June 28, 1989.

22. U.S. NRC, "Results of the Public Workshops," Supplement 1 to Generic Letter 89-10, June 13, 1990.

23. U.S. NRC, "Availability of Program Descriptions," Supplement 2 to Generic Letter 89-10, August 27, 1990.

24. U.S. NRC, "Consideration of the Results of NRC-Sponsored Tests of Motor-Operated Valves," Supplement 3 to Generic Letter 89-10, October 25, 1990.

25. "Early Test Results Air Problems with MOV Diagnostic Gear Accuracy," pp. 1, 13-14, Nucleonics Week, Vol. 32, No. 31, McGraw Hill, August 1, 1991.

26. U.S. NRC, "Guidance on Developing Acceptable Inservice Testing Programs," Generic Letter 89-04, April 3, 1989.

27. U.S. NRC, "Minutes of the Public Meetings on Generic Letter 89-04," October 25, 1989.

28. U.S. NRC, "Erosion/Corrosion Induced Pipe Wall Thinning," Generic Letter 89-08, May 2, 1989.

29. American Nuclear Society, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," ANS-3.2/ANSI N18.7-1976.

30. American Nuclear Society, "American National Standard Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," ANSI/ANS-3.2-1982.

31. U.S. NRC, "NRC Maintenance Inspection Guidance," Volume 1, September 1988.

32. U.S. NRC, "NRC Maintenance Inspection Guidance," Volume 2, September 1988.

33. Johnson, W.G., "MORT: The Management Oversight and Risk Tree," Journal of Safety Research, Vol. 7, No. 1, pp. 4-15, March 1975.

34. Ferry, T.S., "Modern Accident Investigation and Analysis," John Wiley & Sons, Second Edition, pp. 141-182, copyright 1988.

35. Gunther, W., and Subudhi, M., eds., "Insights Gained from Aging Research," NUREG/CR-5643, BNL-NUREG-52323, March 1992.

36. Letter to S. Aggarwal, U.S. NRC, from J.H. Taylor, BNL, dated September 12, 1990, with attachment, "Comments on 'Analysis of Reactor Trips Originating in Balance of Plant Systems' - SAIC Report No. SAIC-89/1148, May 1990."

37. U.S. NRC, "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Vol. 3, November 1988.

38. U.S. NRC, "Service Water System Problems Affecting Safety-Related Equipment," Generic Letter 89-13, July 18, 1989.

39. U.S. NRC, "Service Water System Problems Affecting Safety-Related Equipment," Supplement No. 1 to Generic Letter 89-13, April 4, 1990.

40. U.S. NRC, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," Generic Letter 88-14, August 8, 1988.

41. U.S. NRC, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," Generic Letter 84-15, July 2, 1984.

42. U.S. NRC, "Station Blackout," Regulatory Guide 1.155, August 1988.

43. Hoopingarner, K.R., Zaloudek, F.R., "Aging Mitigation and Improved Programs for Nuclear Service Diesel Generators," NUREG/CR-5057, PNL-6397, December 1989.

44. Gleason, J.F., "Comprehensive Aging Assessment of Circuit Breakers and Relays, Phase II," NUREG-/CR-5762, WYLE 60101, February 1992.

45. Haynes, H.D., "Pump and Valve Research at the Oak Ridge National Laboratory," Proceedings of the Second NRC/ASME Symposium on Pump and Valve Testing, Washington, DC, July 21-23, 1992, NUREG/CP-0123, pp. 351-376, July 1992.

46. U.S. NRC, "Failure of Main Feedwater Check Valves Causes Loss of Feedwater System Integrity and Water Hammer Damage," Information Notice 86-01, January 6, 1986.

47. "Maintenance Software Keeps Machines Up and Running," pp. 63-65, Mechanical Engineering, Vol. 113, No. 11, November 1991. Available in public technical libraries.

48. Moore, T. "The Long View for Nuclear Plant Maintenance," EPRI Journal, pp. 24-33, Electric Power Research Institute, Palo Alto, CA, October/November 1991.

APPENDIX A
CODING SCHEME DEFINITIONS

<u>Area of Finding</u>

SSLF	Storage Shelf Life
STRG	Storage Conditions
CRSN	Corrosion
LKG	Leakage
CTMN	Contamination
VIB	Vibration
IST	In-Service Testing
MCN	Material Condition
MDF	Material Defects (cracks)
DFN	Definitions, wording
MFN	Malfunction
SPPT	Spare parts
PRGM	Program
MTP	Maintenance Practices or Procedures
RTM	Response Timeliness
MGR	Management Response
CMPE	Component Engineering
SYE	System Engineering
CMC	Communications
RCM	Reliability Centered Maintenance
ITP	Inspection Practices
TTP	Testing Practices or Procedures
EVAL	Engineering Evaluation
EQLF	Environmentally qualified lifetime
DSNENG	Design Engineering
MINF	Manufacturers' information
TDG	Trending
ISI	In-Service Inspection
OUTAGERATE	Outage rate
UDVM	Under development, linked to maintenance
PLS	Planning Stages
NOA	No Activity, no current actions
UDVN	Under development, not linked to maintenance
NRC	Used by NRC during MTI
CMPM	Complete, used for maintenance
CMPN	Complete, not used for maintenance
LTUS	Limited Usage
FTP	Failure to Perform
FTIR	Failure to Implement Results
DCM	Documentation
LUB	Lubrication program
CNST	Consistency

APPENDIX A (Cont'd)

Systems

CHAS	Containment Hydrogen Analyzer
CRDM	Control Rod Drive Mechanism
EDGAS	Emergency Diesel Generator Air Start
IAS	Instrument Air System
SAS	Service Air System
EDGLO	Emergency Diesel Generator Lube Oil
CACR	Containment Air Cooing Recirculation
ACCRDM	Air Cooling Control Rod Drive Mechanism
CVCS	Chemical & Volume Control System
EDGFO	Emergency Diesel Generator Fuel Oil
ECCS	Emergency Core Cooling System
SGS	Steam Generators
CRCW	Circulating Water
SDV	Scram Discharge Volume
ICM	Isolation Condenser Makeup
ELCT	Electrical
I&C	Instrumentation & Control
AFW	Auxiliary Feedwater
EFW	Emergency Feedwater
CNDS	Condensate
CCW	Component Cooling Water
SCCW	Secondary Component Cooling Water
VDC	DC Electrical system
RAD	Radiation Protection System
VLPM	Vibration and Loose Parts Monitoring
MFW	Main Feedwater
ELTG	Emergency Lighting
SCWS	Screen Wash System
SRLS	Safety Related Systems - general
SIS	Safety Injection System
CNDSVAC	Condenser Vacuum
RHR	Residual Heat Removal
CRD	Control Rod Drive
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilating and Air Conditioning
RRS	Reactor Recirculation System
VAC	AC Electrical system
CLRC	Containment Leak Rate Control
SWS	Service Water System
NSW	Normal Service Water
CRHVAC	Control Room HVAC
SLC	Standby Liquid Control
BOP	Balance of Plant
CS	Core Spray

APPENDIX A (Cont'd)

EDGCWS	Emergency Diesel Generator Cooling Water System
ICW	Intake Cooling Water
RPS	Reactor Protection System

<u>Components</u>

MOVS	Motor-operated Valves
VLVS	Valves - general
CVS	Control Valves - general
CHVS	Check Valves
TCV	Temperature Control Valves
SRV	Safety Relief Valve
AOV	Air-operated Valve
FUSE	Fuse
CTGS	Coatings
BKRS	Breakers
MSSVS	Main Steam Safety Valves
RAT	Reserve Auxiliary Transformers
MOVTSW	Motor-operated Valve Torque Switch
MSAV	Main Steam Atmospheric Valves
MSIVPT	Main Steam Isolation Valve Poppet
MSIV	Main Steam Isolation Valve
VLVPKG	Valve Packing
DMPR	Damper
XMFR	Transformer
SWGR	Switchgear
CMPR	Compressor
MG	Motor Generator Set
DCP	DC Panels
LOHX	Lube Oil Heat Exchanger
STMTB	Steam Turbine
MCCS	Motor Control Centers
BATCHGRS	Battery Chargers
INSTR	Instrumentation
SNBRS	Snubbers
SFPF	Spent Fuel Pool Filters
PMP	Pump
BPMP	Booster Pump
RLY	Relay
BATS	Batteries
EFPMP	Electric Fire Pump
DFPMP	Diesel Fire Pump
EDGCTPNL	Emergency Diesel Generator Control Panel
XMTRS	Transmitters
MNEXFN	Main Exhaust Fan
PMPPKG	Pump Packing

APPENDIX A (Cont'd)

FLTR	Filter
CMPNTS	Components
MCCBS	Molded Case Circuit Breakers
NTRGN	Nitrogen
CNTMTRADMNTR	Containment Radiation Monitor
HYDRMTRS	Hydromotors
STNR	Strainer
DUCT	Duct
TNKS	Tanks
FCV	Flow Control Valve
FLWXMTRS	Flow Transmitters
480V/THOL	480V Thermal Overload
TSTSW	Test Switch
RRPS	Reactor Recirculation Pump Seal
BUS	Bus

Structures

DW	Drywell
RXPED	Reactor Pedestal
CNPT	Containment Penetrations
TPS	Tunnel Penetration Seal

Other

ASMEXI	ASME B&PV Code Section XI
GNRL	General
EQ	Equipment Qualification
WPKG	Completed Work Packages
CID	Component Identification Codes
DTB	Data Base (Inaccuracies or Omissions)
NPRDS	Nuclear Plant Reliability Data System
QA	Quality Assurance
NCRS	Non Conformance Reports
PRSNL	Personnel
THM	Thermography or infra-red imaging
OSMP	Oil Sampling
EDGEXH	EDG Exhaust Gas
BATVLT	Battery Voltage
HXTTD	Heat Exchanger Terminal Delta Temp.
PPDP	Pump Differential Pressure
MOVATS	Motor Operated Valve Analysis Test System
PHOTO	Photographs
SPA	Shock Pulse Analysis
UST	Ultrasonic Testing
ACM	Acoustic Monitoring
AEM	Acoustic Emission Monitoring

APPENDIX A (Cont'd)

TSMMP	Thermal Shield Movement Monitoring Program
CRSN/ERSN	Corrosion/Erosion Monitoring
PWTHM	Pipe Wall Thickness Measurement
FRG	Ferrography
STBLT	Strobe Light
LKGCNTRL/OW	Leakage Control Oil and Water
RXPR	Reactor Pressure
PRS	Pressure
TMP	Temperature
FLW	Flow
STPT	Setpoint
ECT	Eddy Current Testing
VIS	Visual

APPENDIX B

SAMPLE askSam OUTPUT FOR CALVERT CLIFFS UNITS 1 AND 2

CATEGORY[AGI-ATB-MCN-SGS][AGI-ATB-MTP-GNRL] CODE[CALCLFS-03/90-AGI-01-PAGE{04}]
Integrity of plant steam generators and fuel have remained high resulting in low radiation contamination and health physics problems. Minimal shutdowns resulting from inadequate maintenance.

CATEGORY[AGI-ATB-MCN-BOP-TURB] CODE[CALCLFS-03/90-AGI-02-PAGE{04}]
Housekeeping at turbine building elevation is superb.

CATEGORY[AGI-DFC-MCN-GNRL] CODE[CALCLFS-03/90-AGI-03-PAGE{09}]
Visual condition of plant equipment rooms, floor curbs and miscellaneous bolting could be upgraded. Curbing for flood protection in equipment rooms was cracked and chipped. Missing bolts and washers on equipment supports. (Evaluated as part of NRC Bulletin 79-02 and 79-14).

CATEGORY[AGI-DFC-LKG-LHSI-PMPS] CODE[CALCLFS-03/90-AGI-04-PAGE{11}]
Recurring problem with low head safety injection (LHSI) pumps main flange casing leaks. New gaskets had failed to solve the problem.

CATEGORY[AGI-DFC-MDF-CRHVAC-DUCT] CODE[CALCLFS-03/90-AGI-05-PAGE{11}]
Small holes and seam separation noted in ductwork flexible connectors for post LOCA fans.

CATEGORY[AGI-DFC-MCN-CVCS-TNKS] CODE[CALCLFS-03/90-AGI-06-PAGE{13}]
Bladders in the CVCS suction stabilizer and discharge desurge tanks had failure rate significantly higher than industry average. Possible causes were:
1. Bladder storage conditions and shelf life control.
2. Bladder installation.
3. Precharge pressure being low.
4. Length of time in service.

Seven recommendations made to improve bladder performance.

CATEGORY[AGI-DFC-PRGM-GNRL] CODE[CALCLFS-03/90-AGI-07-PAGE{20}]
Plant aging considerations have not received a high priority for action since other Performance Improvement Program changes have dominated utility resources.

CATEGORY[AGI-DFC-CRSN-SWS-VLVS] CODE[CALCLFS-03/90-AGI-08-PAGE{30}]
Service Water System (SWS) strainer shift valves for ECCS pump room coolers internal parts were severely corroded.

CATEGORY[AGI-DFC-MTP-I&C-PPG] CODE[CALCLFS-03/90-AGI-09-PAGE{31,APX 2}]
Air tubing for a MFW heater control valve had been disconnected at the valve operator and left unplugged by I&C personnel. Protection of open piping under 2 in. diam. is not specified, contrary to good industry practice.

CATEGORY[AGI-DFC-SPPT-CS-PMPS] CODE[CALCLFS-03/90-AGI-10-PAGE{48}]
It was noted that a lack of availability of spare parts for the mechanical seal of a Containment Spray pump contributed to a nearly year long pump outage.

CATEGORY[AGI-DFC-MCN-4KV-BKRS] CODE[CALCLFS-03/90-AGI-11-PAGE{49}]
An air gap of approximately 1/8 in. exists between the track and concrete floor for all 4KV switchgear buses which has caused misalignment between the breakers and MJ switches. However, no operational or emergency condition safety concerns were associated with the track sagging problem.

CATEGORY[PMF-ATB-PRGM-GNRL] CODE[CALCLFS-03/90-PMF-01-PAGE{05}]
Electrical and I&C maintenance staff had well developed corrective and preventive maintenance program. Mechanical maintenance procedures were adequate but could be improved.

CATEGORY[PMF-ATB-PRGM-GNRL] CODE[CALCLFS-03/90-PMF-02-PAGE{16}]
The NRC team determined that the utility had performed a meaningful self assessment in the maintenance area and initiated improved control, performance, and documentation of maintenance work activities.

CATEGORY[PMF-ATB-MTP-GNRL] CODE[CALCLFS-03/90-PMF-03-PAGE{17}]
In the event a procedure is found deficient, workers are instructed to get the procedure changed prior to proceeding with the work. Although the interim effect is to slow the work, in the long term better procedures and work control will result.

CATEGORY[PMF-OBS-MINF-GNRL] CODE[CALCLFS-03/90-PMF-04-PAGE{20}]
Vendor manual control system is maintained by the engineering library and are controlled and updated as new info is received. Engineering reviews the manuals for applicability. The system is relatively new.

CATEGORY[PMF-ATB-MTP-NRC-INFO] CODE[CALCLFS-03/90-PMF-05-PAGE{28}]
Presently, procedures for integrating regulatory information into the maintenance process are being followed.

CATEGORY[PMF-ATB-MTP-ELCT-GNRL] CODE[CALCLFS-03/90-PMF-06-PAGE{32}]
Preventive maintenance (PM) on 480V breakers, protective relaying on the emergency diesel generator (EDG) logic circuits and battery systems was performed satisfactorily.

CATEGORY[PMF-ATB-MINF-MECH] CODE[CALCLFS-03/90-PMF-07-PAGE{47}]
Vendor technical manuals for mechanical maintenance were properly controlled.

CATEGORY[PMF-DFC-MINF-MFW-HTRCV] CODE[CALCLFS-03/90-PMF-08-PAGE{47}]
During maintenance of a MFW heater control valve, a new piston O-ring was supplied instead of the old style piston cup seal ring, for the valve actuator. Engineering had not been properly notified about the change, but a Drawing Change Request was properly issued subsequently.

APPENDIX B (Cont'd)

CATEGORY[PCM-VLN-TTP-I&C-RCS-MNTRS] CODE[CALCLFS-03/90-PCM-01-PAGE{NOV}]
Surveillance test procedure for reactor coolant system (RCS) subcooled margin monitor did not include testing of alarm portion of the channel.

CATEGORY[PCM-ATB-PRGM-CHVS] CODE[CALCLFS-03/90-PCM-02-PAGE{14}]
Utility is actively involved in resolving industry and Calvert Cliffs concerns regarding check valves, as identified in INPO Significant Operating Event Report (SOER) 86-03 and NRC Info Notice 86-01. Nuclear Industry Check (NIC) Valve Group is testing and evaluating non-intrusive testing techniques for check valves. Thirty check valves will be subjected to acoustic monitoring in 1991 of 400 valves at both units. Pericdic testing for forward and reverse flow, where applicable.

CATEGORY[PCM-DFC-OSMP-GNRL] CODE[CALCLFS-03/90-PCM-03-PAGE{19}]
Lube oil sampling program does not define which components should be running before sample is taken. Although each component sampled has a run history, there is no direct correlation between oil sampling and running time.

CATEGORY[PCM-ATB-VIB-GNRL] CODE[CALCLFS-03/90-PCM-04-PAGE{19}]
Vibration data of rotating equipment is recorded monthly. Engineering Safety Features Actuation System (ESFAS) equipment, which is normally idle, is run monthly to take vibration data.

CATEGORY[PCM-DFC-MTP-THM] CODE[CALCLFS-03/90-PCM-05-PAGE{30}]
The lack of programs and equipment used for predictive maintenance, such as infrared thermography techniques, is a weak area.

CATEGORY[PCM-ATB-IST-ELCT-BATS] CODE[CALCLFS-03/90-PCM-06-PAGE{32}]
Electrolyte level, pilot cell specific gravity, temperature cell voltage and battery voltage were within the procedure and Tech Spec limits.

CATEGORY[PCM-DFC-IST-ELCT-BATCHGRS] CODE[CALCLFS-03/90-PCM-07-PAGE{35}]
Present test procedure for battery chargers applies bus load in a step profile which is not the same as the 180 amp instant load the charger would see under actual conditions of return from a station blackout.

CATEGORY[PCM-OBS-DTB-GNRL] CODE[CALCLFS-03/90-PCM-08-PAGE{39}]
The data base for the predictive maintenance program is based on generic failure data instead of plant specific data. Effect of using generic data has not been analyzed.

CATEGORY[PCM-DFC-TTP-I&C-PZR-SRVS-PORVS] CODE[CALCLFS-03/90-PCM-09-PAGE{3' }]
Test procedure for acoustic monitor for one power operated relief valve (PORV) and one safety valve (SRV) did not verify indication and alarm for the instrument channel.

CATEGORY[PMT-ATB-MTP-ELCT-GNRL] CODE[CALCLFS-03/90-PMT-01-PAGE{32}]
Post maintenance testing (PMT) of 480V breakers, protective relaying of the emergency diesel generator (EDG) logic circuits, and battery systems was performed for each component. Subsystem testing of the 480V breakers and EDG logic circuits was postponed until the system test.

CATEGORY[PMT-DFC-MTP-MOVS] CODE[CALCLFS-03/90-PMT-02-PAGE{44}]
A non-conformance report (NCR) documented that a PMT did not give adequate assurance that two MOVs can deliver the design torque under design conditions.

CATEGORY[TDA-OBS-PRGM-GNRL] CODE[CALCLFS-03/90-TDA-01-PAGE{13}]
Independent Safety Evaluation Unit (ISEU) performs investigations and trending of problems encountered in maintenance.

CATEGORY[TDA-OBS-PRGM-NPRDS] CODE[CALCLFS-03/90-TDA-02-PAGE{13}]
Component Failure Analysis Report (CFAR) of the Nuclear Plant Reliabilty Data System (NPRDS) is used by the utility to analyze components with high failure rates at Calvert Cliffs to industry averages.

CATEGORY[TDA-ATB-EVAL-CVCS-TNKS] CODE[CALCLFS-03/90-TDA-03-PAGE{13}]
Component Failure Analysis Report indicated that Chemical and Volume Control System (CVCS) bladders in suction stabilizer and discharge desurge tanks had a high failure rate.

CATEGORY[TDA-ATB-PRGM-CHVS] CODE[CALCLFS-03/90-TDA-04-PAGE{14}]
An extensive component history is maintained for all SOER 86-03 check valves which is periodically updated and some maintenance is trended.

CATEGORY[TDA-DFC-PRGM-GNRL] CODE[CALCLFS-03/90-TDA-05-PAGE{23}]
A trending program based on NPRDS had been initiated. However, no plan of action to implement the results of the program had been developed by the utility, hence the program usefulness is limited.

CATEGORY[TDA-DFC-DTB-GNRL] CODE[CALCLFS-03/90-TDA-06-PAGE{34}]
Historical records are not easily retrievable and the information is not considered suitable for reference. Systems instituted in last 6 months are starting to document and trend work orders, maintenance requests and nonconformance reports. NPRDS activities have been expanded.

CATEGORY[TDA-DFC-MTP-GNRL] CODE[CALCLFS-03/90-TDA-07-PAGE{53,54}]
At the time of the inspection, there was no procedure defining a maintenance trending program. A computerized historical data system using the nuclear maintenance system was recently implemented. Manual acquisition of early data needs to be enhanced.

CATEGORY[RCA-ATB-MGR-GNRL] CODE[CALCLFS-03/90-RCA-01-PAGE{13}]
Management attention is now given to root cause analysis, due to better reporting of work accomplished, better retrieval of component history, and other changes. Meaningful failure analyses can now be performed because appropriate data is available.

CATEGORY[RCA-DFC-FTIR-GNRL] CODE[CALCLFS-03/90-RCA-02-PAGE{23}]
Two RCA reports of components with high failure rates were reviewed and found to be satisfactory, with a detailed analysis and recommended actions. However, no plan to implement these recommended actions had yet been developed, although the reports were completed in late 1989.

CATEGORY[RCA-ATB-PRGM-ELCT-I&C] CODE[CALCLFS-03/90-RCA-03-PAGE{32}]
Approximately 95% of Electrical/I&C personnel have completed latest course in RCA and had a good understanding of their task effort in RCA.

CATEGORY[RCA-ATB-EVAL-GNRL] CODE[CALCLFS-03/90-RCA-04-PAGE{35,50}]
Where RCA has been performed with maintenance personnel paricipation, the work was well documented and proper corrective action taken to resolve the areas that maintenance was assigned. Electrical and I&C personnel also properly understood their requirements in the RCA program.

CATEGORY[RCA-DFC-PRGM-GNRL] CODE[CALCLFS-03/90-RCA-05-PAGE{35}]
Specific guidance in performing and documenting RCA was not defined. Corrective actions have been taken.

CATEGORY[RCA-DFC-EVAL-LKG-SIS-PMPS] CODE[CALCLFS-03/90-RCA-06-PAGE{48}]
RCA had been weak in determining longer term solutions to recurrent problems with flange leaks for both Unit 1 low head safety injection (LHSI) pumps, rather than simply replacing the gaskets.

CATEGORY[PRA-DFC-MTP-GNRL] CODE[CALCLFS-03/90-PRA-01-PAGE{05}]
Utility management has not established specific goals for use of PRA concepts in the maintenance area.

CATEGORY[PRA-OBS-RCM-SWS/SIS/HPSI/LPSI/AFW/IAS]
CODE[CALCLFS-03/90-PRA-02-PAGE{16,24}]
Several safety system analyses using RCM methodology have been completed but results were not scheduled for implementation until end of 1990. Systems are the Salt Water and Service Water, Safety Injection including the High/Low Pressure Injections, the Auxiliary Feedwater, and the Instrument Air Drier System.

CATEGORY[PRA-DFC-MTP-GNRL] CODE[CALCLFS-03/90-PRA-03-PAGE{37}]
For maintenance performed during operations, a five level priority is used. During outages, a three level priority is used. Prioritization is based mainly on operational conditions, Tech Spec requirements, and safety significance (both for NSSS and BOP equipment). Prioritization does not specifically include PRA criteria.

CATEGORY[PRA-DFC-MTP-RCM] CODE[CALCLFS-03/90-PRA-04-PAGE{22}]
The RCM program was conducted for 4 plant systems. However, the results had not been used for several months, and no specific plans for implementation were provided. Hence, the PM program could not be updated.

APPENDIX C

QUANTITATIVE ANALYSIS OF INSIGHTS DERIVED FROM MAINTENANCE TEAM INSPECTION REPORTS

1.0 Discussion

As noted in Section 2.2 of this report, there were seven (7) general categories into which the information extracted from the MTI reports could be placed:

AGI - Specific aging-related insights or management responsiveness to aging concerns.

PMF - Preventive maintenance and incorporation of manufacturers' information.

PCM - Predictive maintenance and condition monitoring techniques.

PMT - Post maintenance testing.

TDA - Failure trending analysis.

RCA - Root cause analysis or failure analysis.

PRA - Use of Probabilistic Risk Assessment (PRA), by the utilities for maintenance and by the NRC for inspection, and/or prioritization of maintenance activities. This was also considered to include Reliabilty Centered Maintenance (RCM).

The categories above were the ones which were considered to have a direct bearing on the management of aging concerns, except for the PRA category which is an indirect influence. They are in general agreement with the terminology associated with maintenance, as described in an EPRI Draft Report concerning nuclear power plant common aging terminology (Ref. C.1).

The next step in categorizing a finding was to consider whether the NRC determined it to be a positive or negative aspect of the utility's maintenance program. This resulted in the following sub-categories:

ATB - Positive aspect or attribute.

OBS - Observation or neutral aspect.

DFC - Negative aspect or deficiency.

FLR - Failure, usually a direct reference to a specific system or component.

VLN - Violation.

As also noted in Section 2.2 of the report, it was decided to provide a count of the positive aspects, the observations, and the negative aspects, failures and violations for each of the major groupings. To show whether or not there was any direct correlation between the quality of the maintenance programs with the age of the plant or type of reactor, the count is presented for each of the major groupings in the ascending order of older to newer plant for each reactor type such as Westinghouse PWRs, Combustion Engineering (CE) and Babcock & Wilcox (B&W) PWRs, and General Electric (GE) BWRs. An overall listing of all plants in ascending order, regardless of reactor type, is also presented for each major grouping.

2.0 Analysis Results

With proper consideration of the limitations concerning the data described in Section 2.2, the authors believe that the quantitative data resulting from this study appearing in Tables C1-1,2,3 to C7-1,2,3 provide some limited insights into the effects of maintenance on aging-related degradation. The data did not show any clear relationship to the age of the plants and so the authors do not believe that any firm conclusions should be drawn from the data set. For this reason, the data are only presented as an appendix to this report.

To illustrate the point concerning the lack of a clear relationship to the age of the plants, the data for three of the categories, i.e. Specific Aging Insights, Predictive Maintenance/Condition Monitoring, and Post Maintenance Testing is analyzed below.

2.1 Specific Aging Insights - Quantitative Analysis

Westinghouse PWRS

Referring to Table C1-2 for the AGI categorizations of the 19 Westinghouse PWR sites, the overall data seems to be relatively flat, with one or two plants rising above the average, in either attributes or deficiencies. It does not appear that age of the plant had any particular relationship to the number of attributes or deficiencies identified.

CE and B&W PWRS

Table C1-2 shows the AGI categorizations of the 11 sites, only one of which, ANO, contains a B&W unit. As with the Westinghouse PWRS, the data appears to be relatively flat, with only one or two plants as outliers in the deficiency category. Again, it does not appear that age of the plant had any particular relationship to the number of attributes or deficiencies defined.

GE BWRS

Finally, the AGI categorizations for 17 GE BWR sites in Table C1-3 again show no particular pattern, with only one plant considered a slight outlier in the deficiency category.

Conclusions

It appears that regarding any identified aging-related degradation of systems, components or structures, the MTI reports show no particular relationship of a plant's age to the number of attributes or deficiencies existing.

2.2 Predictive Maintenance and Condition Monitoring - Quantitative Insights

Unlike the numerical findings related to the Aging category in the previous section, there was a greater balance between the number of deficiencies versus the number of positive aspects. In a few cases, the number of positive aspects noticeably outweighed the number of deficiencies. If one considers the listing of all plants regardless of reactor type in Table C3-1, it appears that some of the very oldest plants were making a conscious effort to apply predictive maintenance and condition monitoring techniques, as indicated by the larger ratio of positive aspects to deficiencies. This of course is what one would expect: that the need for condition monitoring is considered by plant management to become a higher priority as a plant ages.

2.3 Post Maintenance Testing - Quantitative Insights

Westinghouse PWRs

In reviewing the data of Tables C4-1 to C4-3, there were indications that the old plants were doing a satisfactory or above average job in PMT. However, as with most of the other categories so far, there does not appear to be a measurable trend based on age of the plant.

CE and B&W PWRs

There seemed to be an unusually high number of PMT deficiencies amongst these plants compared to other NSSS design plants. However, this can only be related to the performance of the individual utility, since the NSSS supplier normally has no role in PMT activities. Again, the pattern does not seem to be a function of plant age.

General Electric BWRs

For these plants, no discernible trend appears in the data as a function of plant age. The older plants did not seem to be performing significantly better or worse than the others. Overall, there was no discernible trend based on age of the plant.

3.0 Reference

1. Electric Power Research Institute, "Nuclear Power Plant Common Aging Terminology - Draft Report for Trial Use and Comment," Palo Alto, CA, May 1991.

Table C1-1: Aging Insights - Quantitative Analysis
All 44 Plant Sites

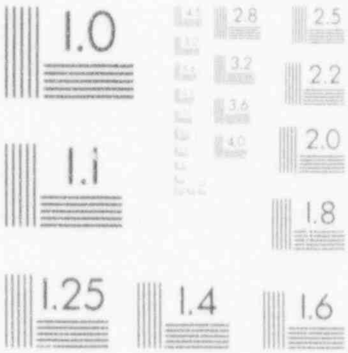
ANALYSIS FOR AGI

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	3	0	3	1	0
HADNCK	1-68	6	0	1	0	0
SONGS123	1-68	1	0	4	0	0
NMP1	12-69	0	0	1	0	0
DRES23	6-70	0	1	5	0	2
GINNA	7-70	2	0	3	0	0
HBRBSN	3-71	3	0	6	0	0
MLSTN1	3-71	1	0	1	0	0
PLSDS	12-71	3	0	12	0	0
VY1	11-72	2	0	3	0	0
SY12	12-72	2	0	14	2	0
MY1	12-72	4	0	1	0	0
FTCLHN1	9-73	2	0	4	0	0
ZION12	12-73	0	0	6	0	0
PRIEISL	12-73	4	0	2	0	1
COOPER1	7-74	1	0	6	1	2
PB23	7-74	0	2	1	0	1
IP2	8-74	0	0	7	1	0
ANO12	12-74	1	0	6	1	0
DAEC1	2-75	2	0	3	1	3
RANSECO1	4-75	2	0	2	0	0
CALCLFS	5-75	2	0	9	0	0
FITZ1	7-75	2	0	4	0	1
DCCK12	8-75	0	0	1	1	0
HATCH12	12-75	3	1	3	0	0
MLSTN2	12-75	1	0	1	0	0
IP3	8-76	0	1	0	0	0
STLC12	12-76	2	0	5	1	0
SLM12	6-77	0	0	2	0	0
NOANNA12	6-78	4	0	4	0	0
SQYH12	7-81	7	0	6	0	1
MCGUIRE	12-81	4	0	7	0	0
LASLL	1-84	2	0	3	0	0
GRGLF1	7-85	0	0	2	0	0
WSES3	9-85	5	0	3	0	0
PV123	1-86	0	1	1	1	0
LIM1	2-86	0	0	6	0	0
MLSTN3	4-86	1	0	1	0	0
RIVBND1	6-86	1	0	6	1	0
HPCRK	12-86	2	1	0	0	0
CLPWST	4-87	2	0	8	2	0
SH1	5-87	0	0	9	0	0
PERRY1	11-87	1	0	3	0	0
FERMI2	1-88	2	0	6	0	0
BDWD	7-88	4	0	2	0	0
SOTXS12	8-88	4	0	6	0	0
TOTALS		88	7	189	13	11

GRAND SUM OF OBSERVATIONS 308

2

IMAGE EVALUATION TEST TARGET (MT-3)



150mm

6"

PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

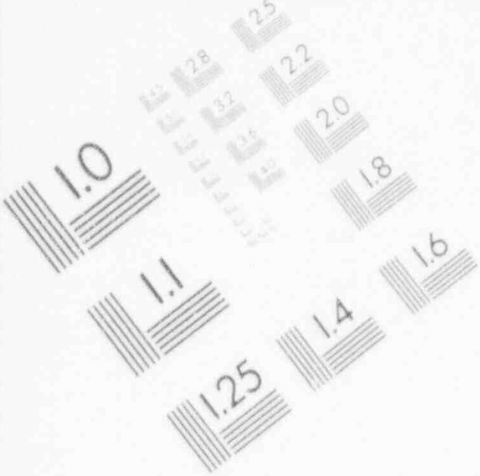
2

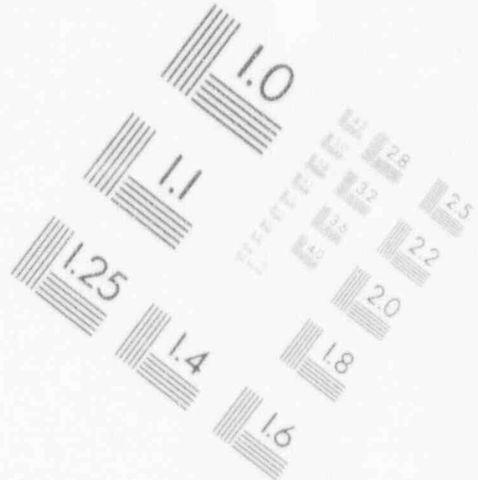
IMAGE EVALUATION TEST TARGET (MT-3)

150mm

6"

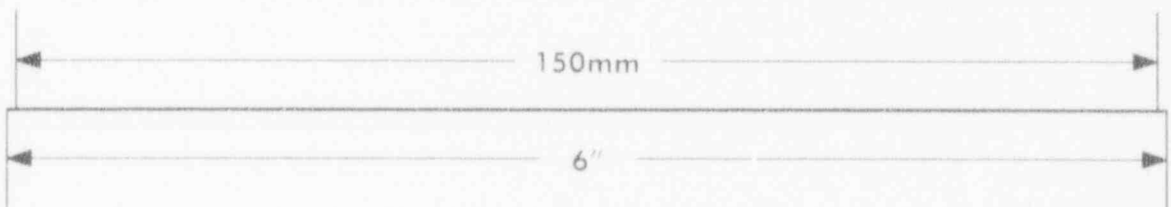
PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

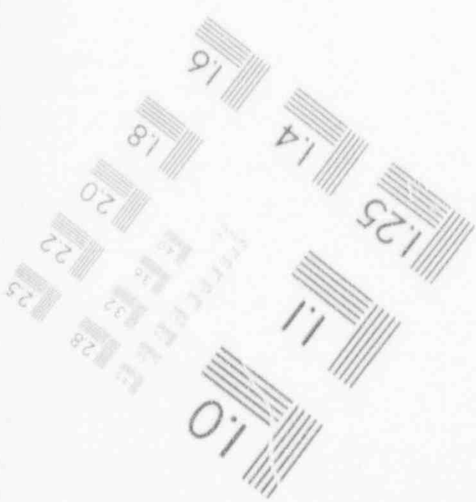


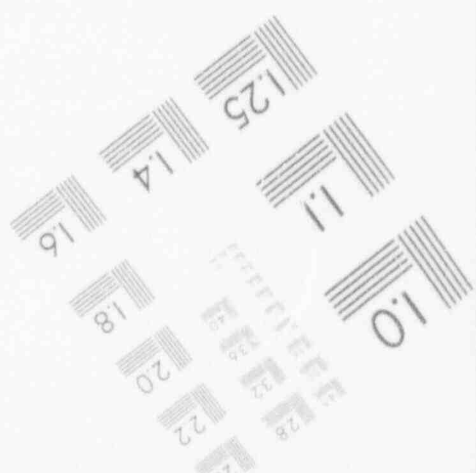


2

IMAGE EVALUATION TEST TARGET (MT-3)







PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

2

IMAGE EVALUATION TEST TARGET (MT-3)

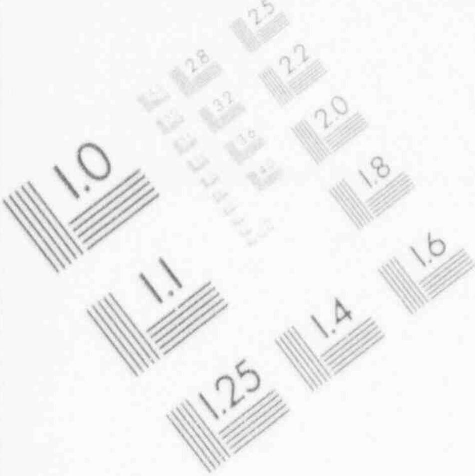
150mm

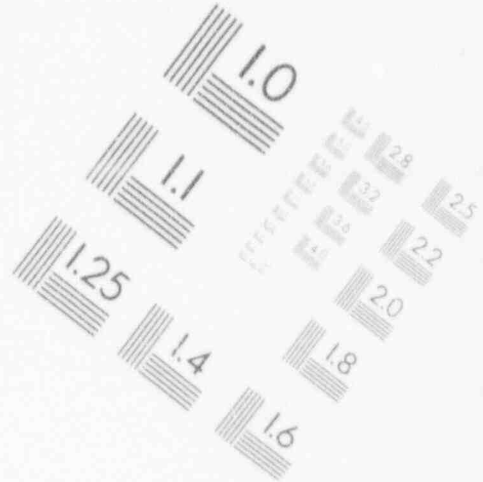
6″

PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

2

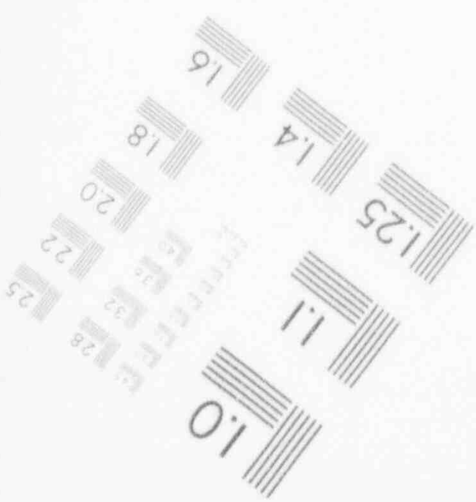
IMAGE EVALUATION TEST TARGET (MT-3)

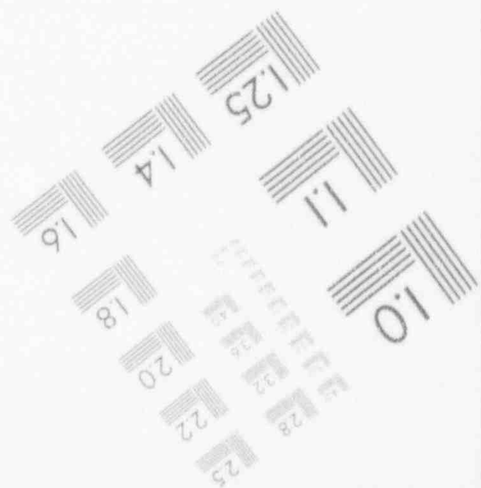




150mm

6"





PHOTOGRAPHIC SCIENCES CORPORATION
770 BASKET ROAD
P.O. BOX 338
WEBSTER, NEW YORK 14580
(716) 265-1600

Table C1-2: Aging Insights - Quantitative Analysis - PWRs

ANALYSIS FOR AGI

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	3	0	3	1	0
HADNCK	1-68	6	0	1	0	0
SONGS123	1-68	1	0	4	0	0
GINNA	7-70	2	0	3	0	0
HBRBSN	3-71	3	0	6	0	0
SY12	12-72	2	0	14	2	0
ZION12	12-73	0	0	6	0	0
PRIEISL	12-73	4	0	2	0	1
IP2	8-74	0	0	7	1	0
DCCK12	8-75	0	0	[illegible]	1	0
IP3	8-76	0	1	[illegible]	0	0
SLM12	6-77	0	0	2	0	0
NOANNA12	6-78	4	0	4	0	0
SQYH12	7-81	7	0	6	0	1
MCGUIRE	12-81	4	0	7	0	0
MLSTN3	4-86	1	0	1	0	0
SH1	5-87	0	0	9	0	0
BDWD	7-88	4	0	2	0	0
[illegible]TXS12	8-88	4	0	6	0	0
TOTALS		45	1	84	5	2
GRAND SUM OF OBSERVATIONS				137		

ANALYSIS FOR AGI

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	1	0	4	0	0
PLSDS	12-71	3	0	12	0	0
MY1	12-72	4	0	1	0	0
FTCLHN1	9-73	2	0	4	0	0
ANO12	12-74	1	0	6	1	0
RANSECO1	4-75	2	0	2	0	0
CALCLFS	5-75	[illegible]	0	9	0	0
MLSTN2	12-75	1	0	1	0	0
STLC12	12-76	2	0	5	1	0
WSES3	9-85	5	0	3	0	0
PV123	1-86	0	1	1	1	0
TOTALS		23	1	48	3	0
GRAND SUM OF OBSERVATIONS				75		

Table C1-3: Aging Insights - Quantitative Analysis - BWRs

ANALYSIS FOR AGI

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	0	0	1	0	0
DRES23	6-70	0	1	5	0	2
MLSTN1	3-71	1	0	1	0	0
VY1	11-72	2	0	3	0	0
PB23	7-74	0	2	1	0	1
COOPER1	7-74	1	0	6	1	2
DAEC1	2-75	2	0	3	1	3
FITZ1	7-75	2	0	4	0	1
HATCH12	12-75	3	1	3	0	0
LASLL	1-84	2	0	3	0	0
GRGLF1	7-85	0	0	2	0	0
LIM1	2-86	0	0	6	0	0
RIVBND1	6-86	1	0	6	1	0
HPCRK	12-86	2	1	0	0	0
CLPWST	4-87	2	0	8	2	0
PERRY1	11-87	1	0	3	0	0
FERMI2	1-88	2	0	6	0	0
TOTALS		21	5	61	5	9

GRAND SUM OF OBSERVATIONS 101

Table C2-1: Preventive Maintenance Insights - Quantitative Analysis
All 44 Plant Sites

ANALYSIS FOR PMF

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	4	0	0	0	0
HADNCK	1-68	7	0	4	0	0
SONGS123	1-68	0	0	1	0	0
NMP1	12-69	0	1	0	0	0
DRES23	6-70	6	1	6	0	1
GINNA	7-70	6	0	2	0	0
HBRBSN	3-71	3	0	3	0	0
MLSTN1	3-71	2	0	0	0	0
PLSDS	12-71	3	0	2	0	1
VY1	11-72	0	0	3	0	0
SY12	12-72	0	0	2	0	1
MY1	12-72	4	2	6	0	0
FTCLHN1	9-73	0	0	2	0	0
ZION12	12-73	1	0	1	0	0
PRIEISL	12-73	1	0	2	0	1
COOPER1	7-74	2	0	6	0	1
PB23	7-74	0	1	1	0	0
IP2	8-74	2	0	7	0	0
ANO12	12-74	0	2	0	0	0
DAEC1	2-75	0	0	4	0	0
RANSECO1	4-75	1	0	5	0	1
CALCLFS	5-75	6	1	1	0	0
FITZ1	7-75	2	1	2	0	0
DCCK12	8-75	0	1	0	0	0
HATCH12	12-75	0	0	1	0	0
MLSTN2	12-75	1	0	0	0	0
IP3	8-76	1	0	2	0	0
STLC12	12-76	0	0	8	0	0
SLM12	6-77	0	0	3	0	0
NOANNA12	6-78	1	0	7	0	0
SQYH12	7-81	3	0	5	0	0
MCGUIRE	12-81	10	0	1	0	0
LASLL	1-84	0	0	1	0	0
GRGLF1	7-85	0	0	3	0	0
WSES3	9-85	2	0	6	0	2
PV123	1-86	0	0	1	0	0
LIM1	2-86	0	0	0	0	0
MLSTN3	4-86	0	0	0	0	0
RIVBND1	6-86	3	0	4	0	0
HPCRK	12-86	2	1	1	0	0
CLPWST	4-87	1	1	7	0	0
SH1	5-87	1	0	4	0	0
PERRY1	11-87	9	3	1	0	0
FERMI2	1-88	4	0	1	0	3
BDWD	7-88	4	0	2	0	0
SOTXS12	8-88	3	0	6	0	1
TOTALS		95	15	124	0	12
GRAND SUM OF OBSERVATIONS				246		

Table C2-2: **Preventive Maintenance Insights - Quantitative Analysis - PWRs**

ANALYSIS FOR PMF

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	4	0	0	0	0
HADNCK	1-68	7	0	4	0	0
SONGS123	1-68	0	0	1	0	0
GINNA	7-70	6	0	2	0	0
HBRBSN	3-71	3	0	3	0	0
SY12	12-72	0	0	2	0	1
ZION12	12-73	1	0	1	0	0
PRIEISL	12-73	1	0	2	0	1
IP2	8-74	2	0	7	0	0
DCCK12	8-75	0	1	0	0	0
IP3	8-76	1	0	2	0	0
SLM12	6-77	0	0	3	0	0
NOANNA12	6-78	1	0	7	0	0
SQYH12	7-81	3	0	5	0	0
MCGUIRE	12-81	10	0	1	0	0
MLSTN3	4-86	0	0	0	0	0
SH1	5-87	1	0	4	0	0
BDWD	7-88	4	0	2	0	0
SOTXS12	8-88	3	0	6	0	1
TOTALS		47	1	52	0	3
GRAND SUM OF OBSERVATIONS				103		

ANALYSIS FOR PMF

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	0	0	1	0	0
PLSDS	12-71	3	0	2	0	1
MY1	12-72	4	2	6	0	0
FTCLHN1	9-73	0	0	2	0	0
ANO12	12-74	0	2	0	0	0
RANSECO1	4-75	1	0	5	0	1
CALCLFS	5-75	6	1	1	0	0
MLSTN2	12-75	1	0	0	0	0
STLC12	12-76	0	0	8	0	0
WSES3	9-85	2	0	6	0	2
PV123	1-86	0	0	1	0	0
TOTALS		17	5	32	0	4
GRAND SUM OF OBSERVATIONS				58		

Table C2-3: Preventive Maintenance Insights - Quantitative Analysis - BWRs

ANALYSIS FOR PMF

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	0	1	0	0	0
DRES23	6-70	6	1	6	0	1
MLSTN1	3-71	2	0	0	0	0
VY1	11-72	0	0	3	0	0
PB23	7-74	0	1	1	0	0
COOPER1	7-74	2	0	6	0	1
DAEC1	2-75	0	0	4	0	0
FITZ1	7-75	2	1	2	0	0
HATCH12	12-75	0	0	1	0	0
LASLL	1-84	0	0	1	0	0
GRGLF1	7-85	0	0	3	0	0
LIM1	2-86	0	0	0	0	0
RIVBND1	6-86	3	0	4	0	0
HPCRK	12-86	2	1	1	0	0
CLPWST	4-87	1	1	7	0	0
PERRY1	11-87	9	3	1	0	0
FERMI2	1-88	4	0	1	0	3
TOTALS		31	9	41	0	5

GRAND SUM OF OBSERVATIONS 86

Table C3-1: Predictive Maintenance and Condition Monitoring Quantitative Analysis - All 44 Plant Sites

ANALYSIS FOR PCM

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	5	0	1	0	0
HADNCK	1-68	4	0	0	0	0
SONGS123	1-68	4	0	0	0	0
NMP1	12-69	0	2	0	0	0
DRES23	6-70	1	1	1	0	0
GINNA	7-70	4	0	0	0	0
HBRBSN	3-71	3	0	5	0	0
MLSTN1	3-71	0	1	0	0	0
PLSDS	12-71	2	0	2	0	0
VY1	11-72	1	0	0	0	0
SY12	12-72	2	0	2	0	1
MY1	12-72	1	0	0	0	0
FTCLHN1	9-73	1	1	3	0	0
ZION12	12-73	1	2	0	0	2
PRIEISL	12-73	1	0	4	0	0
COOPER1	7-74	1	1	3	0	0
PB23	7-74	0	1	0	0	0
IP2	8-74	1	0	1	0	0
ANO12	12-74	1	1	1	0	0
DAEC1	2-75	0	0	1	0	0
RANSECO1	4-75	0	0	1	1	0
CALCLFS	5-75	3	1	4	0	1
FITZ1	7-75	3	1	0	0	0
DCCK12	8-75	1	1	0	0	0
HATCH12	12-75	0	1	2	0	1
MLSTN2	12-75	0	0	0	0	0
IP3	8-76	0	7	0	0	0
STLC12	12-76	2	0	2	0	0
SLM12	6-77	2	0	0	0	0
NOANNA12	6-78	3	0	5	0	0
SQYH12	7-81	9	0	7	0	0
MCGUIRE	12-81	8	1	3	0	0
LASLL	1-84	0	2	2	0	0
GRGLF1	7-85	0	0	0	0	0
WSES3	9-85	1	0	3	0	0
PV123	1-86	0	0	2	0	0
LIM1	2-86	0	2	0	0	0
MLSTN3	4-86	1	0	0	0	0
RIVBND1	6-86	7	0	1	0	1
HPCRK	12-86	1	0	2	0	0
CLPWST	4-87	3	1	0	0	0
SH1	5-87	2	3	6	0	0
PERRY1	11-87	1	2	0	0	2
FERMI2	1-88	5	0	2	0	1
BDWD	7-88	6	1	6	0	0
SOTXS12	8-88	2	0	1	0	0
TOTALS		93	33	73	1	9

GRAND SUM OF OBSERVATIONS 209

Table C3-2: Predictive Maintenance and Condition Monitoring - Quantitative Analysis - PWRs

ANALYSIS FOR PCM

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	5	0	1	0	0
HADNCK	1-68	4	0	0	0	0
SONGS123	1-68	4	0	0	0	0
GINNA	7-70	4	0	0	0	0
HBRBSN	3-71	3	0	5	0	0
SY12	12-72	2	0	2	0	1
ZION12	12-73	1	2	0	0	2
PRIEISL	12-73	1	0	4	0	0
IP2	8-74	1	0	1	0	0
DCCK12	8-75	1	1	0	0	0
IP3	8-76	0	7	0	0	0
SLM12	6-77	2	0	0	0	0
NOANNA12	6-78	3	0	5	0	0
SQYH12	7-81	9	0	7	0	0
MCGUIRE	12-81	8	1	3	0	0
MLSTN3	4-86	1	0	0	0	0
SH1	5-87	2	3	6	0	0
BDWD	7-88	6	1	6	0	0
SOTXS12	8-88	2	0	1	0	0
TOTALS		59	15	41	0	3

GRAND SUM OF OBSERVATIONS 118

ANALYSIS FOR PCM

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	4	0	0	0	0
PLSDS	12-71	2	0	2	0	0
MY1	12-72	1	0	0	0	0
FTCLHN1	9-73	1	1	3	0	0
ANO12	12-74	1	1	1	0	0
RANSECO1	4-75	0	0	1	1	0
CALCLFS	5-75	3	1	4	0	1
MLSTN2	12-75	0	0	0	0	0
STLC12	12-76	2	0	2	0	0
WSES3	9-85	1	0	3	0	0
PV123	1-86	0	0	2	0	0
TOTALS		15	3	18	1	1

GRAND SUM OF OBSERVATIONS 38

Table C3-3: Predictive Maintenance and Condition Monitoring - Quantitative Analysis - BWRs

ANALYSIS FOR PCM

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	0	2	0	0	0
DRES23	6-70	1	1	1	0	0
MLSTN1	3-71	0	1	0	0	0
VY1	11-72	1	0	0	0	0
PB23	7-74	0	1	0	0	0
COOPER1	7-74	1	1	3	0	0
DAEC1	2-75	0	0	1	0	0
FITZ1	7-75	3	1	0	0	0
HATCH12	12-75	0	1	2	0	1
LASLL	1-84	0	2	2	0	0
GRGLF1	7-85	0	0	0	0	0
LIM1	2-86	0	2	0	0	0
RIVBND1	6-86	7	0	1	0	1
HPCRK	12-86	1	0	2	0	0
CLPWST	4-87	3	1	0	0	0
PERRY1	11-87	1	2	0	0	2
FERMI2	1-88	5	0	2	0	1
TOTALS		23	15	14	0	5

GRAND SUM OF OBSERVATIONS 57

Table C4-1: Post Maintenance Testing - Quantitative Analysis
All 44 Plant Sites

ANALYSIS FOR PMT

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	2	0	0	0	0
HADNCK	1-68	2	0	0	0	0
SONGS123	1-68	0	0	2	0	0
NMP1	12-69	0	0	0	0	0
DRES23	6-70	1	0	0	0	0
GINNA	7-70	3	0	0	0	0
HBRBSN	3-71	0	0	2	0	0
MLSTN1	3-71	0	0	2	0	0
PLSDS	12-71	0	0	0	0	1
VY1	11-72	0	0	1	0	0
SY12	12-72	0	0	1	0	0
MY1	12-72	4	0	0	0	0
FTCLHN1	9-73	0	1	2	0	0
ZION12	12-73	0	0	2	0	0
PRIEISL	12-73	1	0	0	0	0
COOPER1	7-74	0	0	5	0	0
PB23	7-74	0	1	0	0	0
IP2	8-74	2	0	0	0	0
ANO12	12-74	0	0	1	0	0
DAEC1	2-75	0	0	1	0	0
RANSECO1	4-75	0	0	3	0	1
CALCLFS	5-75	1	0	1	0	0
FITZ1	7-75	1	0	3	0	0
DCCK12	8-75	0	0	0	0	0
HATCH12	12-75	1	0	2	0	0
MLSTN2	12-75	0	0	1	0	0
IP3	8-76	1	1	1	0	0
STLC12	12-76	0	0	6	0	0
SLM12	6-77	1	1	0	0	0
NOANNA12	6-78	3	0	4	0	0
SQYH12	7-81	2	0	1	0	0
MCGUIRE	12-81	1	0	1	0	0
LASLL	1-84	0	0	1	0	0
GRGLF1	7-85	1	0	0	0	0
WSES3	9-85	0	0	3	0	0
PV123	1-86	0	0	0	0	0
LIM1	2-86	0	0	0	0	0
MLSTN3	4-86	0	0	2	0	0
RIVBND1	6-86	0	0	0	0	0
HPCRK	12-86	1	0	0	0	0
CLPWST	4-87	[illegible]	0	2	0	0
SH1	5-87	0	1	0	0	0
PERRY1	11-87	1	0	0	0	0
FERMI2	1-88	1	0	3	0	1
BDWD	7-88	1	0	1	0	0
SOTXS12	8-88	1	0	2	0	0
TOTALS		32	5	56	0	3

GRAND SUM OF OBSERVATIONS 96

Table C4-2: Post Maintenance Testing - Quantitative Analysis - PWRs

ANALYSIS FOR PMT

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	2	0	0	0	0
HADNCK	1-68	2	0	0	0	0
SONGS123	1-68	0	0	2	0	0
GINNA	7-70	3	0	0	0	0
HBRBSN	3-71	0	0	2	0	0
SY12	12-72	0	0	1	0	0
ZION12	12-73	0	0	2	0	0
PRIEISL	12-73	1	0	0	0	0
IP2	8-74	2	0	0	0	0
DCCK12	8-75	0	0	0	0	0
IP3	8-76	1	1	1	0	0
SLM12	6-77	1	1	0	0	0
NOANNA12	6-78	3	0	4	0	0
SQYH12	7-81	2	0	1	0	0
MCGUIRE	12-81	1	0	1	0	0
MLSTN3	4-86	0	0	2	0	0
SH1	5-87	0	1	0	0	0
BDWD	7-88	1	0	1	0	0
SOTXS12	8-88	1	0	2	0	0
TOTALS		20	3	19	0	0
GRAND SUM OF OBSERVATIONS				42		

ANALYSIS FOR PMT

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	0	0	2	0	0
PLSDS	12-71	0	0	0	0	1
MY1	12-72	4	0	0	0	0
FTCLHN1	9-73	0	1	2	0	0
ANO12	12-74	0	0	1	0	0
RANSECO1	4-75	0	0	3	0	1
CALCLFS	5-75	1	0	1	0	0
MLSTN2	12-75	0	0	1	0	0
STLC12	12-76	0	0	6	0	0
WSES3	9-85	0	0	3	0	0
PV123	1-86	0	0	0	0	0
TOTALS		5	1	19	0	2
GRAND SUM OF OBSERVATIONS				27		

Table C4-3: Post Maintenance Testing - Quantitative Analysis - BWRs

ANALYSIS FOR PMT

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	0	0	0	0	0
DRES23	6-70	1	0	0	0	0
MLSTN1	3-71	0	0	2	0	0
VY1	11-72	0	0	1	0	0
PB23	7-74	0	1	0	0	0
COOPER1	7-74	0	0	5	0	0
DAEC1	2-75	0	0	1	0	0
FITZ1	7-75	1	0	3	0	0
HATCH12	12-75	1	0	2	0	0
LASLL	1-84	0	0	1	0	0
GRGLF1	7-85	1	0	0	0	0
LIM1	2-86	0	0	0	0	0
RIVBND1	6-86	0	0	0	0	0
HPCRK	12-86	1	0	0	0	0
CLPWST	4-87	0	0	2	0	0
PERRY1	11-87	1	0	0	0	0
FERMI2	1-88	1	0	3	0	1
TOTALS		7	1	20	0	1

GRAND SUM OF OBSERVATIONS 29

Table C5-1: Failure Trending - Quantitative Analysis
All 44 Plant Sites

ANALYSIS FOR TDA

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	2	2	3	0	0
HADNCK	1-68	7	0	5	0	0
SONGS123	1-68	2	0	1	0	0
NMP1	12-69	1	0	1	0	0
DRES23	6-70	6	0	7	0	0
GINNA	7-70	1	0	2	0	0
HBRBSN	3-71	1	0	7	0	0
MLSTN1	3-71	2	0	0	0	0
PLSDS	12-71	2	0	1	0	0
VY1	11-72	1	0	1	0	0
SY12	12-72	0	0	1	0	0
MY1	12-72	2	0	4	0	0
FTCLHN1	9-73	0	0	2	0	0
ZION12	12-73	1	0	1	0	0
PRIEISL	12-73	1	0	4	0	3
COOPER1	7-74	1	1	12	0	0
PB23	7-74	3	0	2	0	0
IP2	8-74	3	1	7	0	0
ANO12	12-74	0	0	7	0	0
DAEC1	2-75	1	0	1	0	0
RANSECO1	4-75	0	0	4	0	0
CALCLFS	5-75	2	2	3	0	0
FITZ1	7-75	3	0	6	0	0
DCCK12	8-75	1	0	0	0	0
HATCH12	12-75	1	1	0	0	0
MLSTN2	12-75	1	0	1	0	0
IP3	8-76	3	0	1	0	0
STLC12	12-76	4	0	1	0	0
SLM12	6-77	1	0	1	0	0
NOANNA12	6-78	1	0	1	0	0
SQYH12	7-81	2	0	5	0	0
MCGUIRE	12-81	4	0	4	0	0
LASLL	1-84	3	0	8	0	0
GRGLF1	7-85	4	0	5	0	0
WSES3	9-85	2	0	2	0	0
PV123	1-86	0	0	2	0	0
LIM1	2-86	1	0	0	0	0
MLSTN3	4-86	0	0	1	0	0
RIVBND1	6-86	6	0	8	0	0
HPCRK	12-86	4	0	0	0	1
CLPWST	4-87	2	0	2	0	0
SH1	5-87	0	0	0	0	0
PERRY1	11-87	3	0	0	0	0
FERMI2	1-88	5	0	5	0	1
BDWD	7-88	6	0	2	0	0
SOTXS12	8-88	9	0	3	0	0
TOTALS		105	7	134	0	5

GRAND SUM OF OBSERVATIONS 251

Table C5-2: Failure Trending - Quantitative Analysis - PWRs

ANALYSIS FOR TDA

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	2	2	3	0	0
HADNCK	1-68	7	0	5	0	0
SONGS123	1-68	2	0	1	0	0
GINNA	7-70	1	0	2	0	0
HBRBSN	3-71	1	0	7	0	0
SY12	12-72	0	0	1	0	0
ZION12	12-73	1	0	1	0	0
PRIEISL	12-73	1	0	4	0	3
IP2	8-74	3	1	7	0	0
DCCK12	8-75	1	0	0	0	0
IP3	8-76	3	0	1	0	0
SLM12	6-77	1	0	1	0	0
NOANNA12	6-78	1	0	1	0	0
SQYH12	7-81	2	0	5	0	0
MCGUIRE	12-81	4	0	4	0	0
MLSTN3	4-86	0	0	1	0	0
SH1	5-87	0	0	0	0	0
BDWD	7-88	6	0	2	0	0
SOTXS12	8-88	9	0	3	0	0
TOTALS		45	3	49	0	3
GRAND SUM OF OBSERVATIONS				100		

ANALYSIS FOR TDA

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	2	0	1	0	0
PLSDS	12-71	2	0	1	0	0
MY1	12-72	2	0	4	0	0
FTCLHN1	9-73	0	0	2	0	0
ANO12	12-74	0	0	7	0	0
RANSECO1	4-75	0	0	4	0	0
CALCLFS	5-75	2	2	3	0	0
MLSTN2	12-75	1	0	1	0	0
STLC12	12-76	4	0	1	0	0
WSES3	9-85	2	0	2	0	0
PV123	1-86	0	0	2	0	0
TOTALS		15	2	28	0	0
GRAND SUM OF OBSERVATIONS				45		

Table C5-3: Failure Trending - Quantitative Analysis - BWRs

ANALYSIS FOR TDA

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	1	0	1	0	0
DRES23	6-70	6	0	7	0	0
MLSTN1	3-71	2	0	0	0	0
VY1	11-72	1	0	1	0	0
PB23	7-74	3	0	2	0	0
COOPER1	7-74	1	1	12	0	0
DAEC1	2-75	1	0	1	0	0
FITZ1	7-75	3	0	6	0	0
HATCH12	12-75	1	1	0	0	0
LASLL	1-84	3	0	8	0	0
GRGLF1	7-85	4	0	5	0	0
LIM1	2-86	1	0	0	0	0
RIVBND1	6-86	6	0	8	0	0
HPCRK	12-86	4	0	0	0	1
CLPWST	4-87	2	0	2	0	0
PERRY1	11-87	3	0	0	0	0
FERMI2	1-88	5	0	5	0	1
TOTALS		47	2	58	0	2
GRAND SUM OF OBSERVATIONS				109		

Table C6-1: Root Cause Analysis - Quantitative Analysis
All 44 Plant Sites

ANALYSIS FOR RCA

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	0	0	2	0	0
HADNCK	1-68	1	0	1	0	0
SONGS123	1-68	0	0	1	0	0
NMP1	12-69	1	0	0	0	0
DRES23	6-70	2	0	4	0	0
GINNA	7-70	3	0	1	0	0
HBRBSN	3-71	2	0	4	0	0
MLSTN1	3-71	2	0	0	0	0
PLSDS	12-71	0	0	5	0	0
VY1	11-72	1	0	0	0	0
SY12	12-72	1	0	0	0	0
MY1	12-72	2	0	0	0	0
FTCLHN1	9-73	0	0	2	0	0
ZION12	12-73	0	0	2	0	0
PRIEISL	12-73	0	0	0	0	4
COOPER1	7-74	2	1	12	0	0
PB23	7-74	0	0	0	0	0
IP2	8-74	0	0	3	0	0
ANO12	12-74	0	0	3	0	0
DAEC1	2-75	0	0	6	0	2
RANSECO1	4-75	0	0	1	0	1
CALCLFS	5-75	3	0	3	0	0
FITZ1	7-75	1	0	2	0	0
DCCK12	8-75	0	0	1	0	0
HATCH12	12-75	1	0	2	0	0
MLSTN2	12-75	0	0	1	0	0
IP3	8-76	2	0	1	0	0
STLC12	12-76	1	0	2	0	0
SLM12	6-77	0	0	1	0	0
NOANNA12	6-78	0	1	2	0	0
SQYH12	7-81	0	0	1	0	0
MCGUIRE	12-81	1	0	3	0	0
LASLL	1-84	0	0	1	0	0
GRGLF1	7-85	0	0	2	0	0
WSES3	9-85	1	0	0	0	0
PV123	1-86	0	0	2	0	1
LIM1	2-86	1	0	0	0	0
MLSTN3	4-86	1	0	0	0	0
RIVBND1	6-86	2	0	5	0	0
HPCRK	12-86	0	0	1	0	1
CLPWST	4-87	0	0	1	0	0
SH1	5-87	1	0	1	0	0
PERRY1	11-87	5	0	0	0	1
FERMI2	1-88	2	0	5	0	0
BDWD	7-88	2	0	0	0	0
SOTXS12	8-88	4	0	0	0	0
TOTALS		45	2	84	0	10

GRAND SUM OF OBSERVATIONS 141

Table C6-2: Root Cause Analysis - Quantitative Analysis - PWRs

ANALYSIS FOR RCA

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	0	0	2	0	0
HADNCK	1-68	1	0	1	0	0
SONGS123	1-68	0	0	1	0	0
GINNA	7-70	3	0	1	0	0
HBRBSN	3-71	2	0	4	0	0
SY12	12-72	1	0	0	0	0
ZION12	12-73	0	0	2	0	0
PRIEISL	12-73	0	0	0	0	4
IP2	8-74	0	0	3	0	0
DCCK12	8-75	0	0	1	0	0
IP3	8-76	2	0	1	0	0
SLM12	6-77	0	0	1	0	0
NOANNA12	6-78	0	1	2	0	0
SQYH12	7-81	0	0	1	0	0
MCGUIRE	12-81	1	0	3	0	0
MLSTN3	4-86	1	0	0	0	0
SH1	5-87	1	0	1	0	0
BDWD	7-88	2	0	0	0	0
SOTXS12	8-88	4	0	0	0	0
TOTALS		18	1	24	0	4
GRAND SUM OF OBSERVATIONS				47		

ANALYSIS FOR RCA

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	0	0	1	0	0
PLSDS	12-71	0	0	5	0	0
MY1	12-72	2	0	0	0	0
FTCLHN1	9-73	0	0	2	0	0
ANO12	12-74	0	0	3	0	0
RANSECO1	4-75	0	0	1	0	1
CALCLFS	5-75	3	0	3	0	0
MLSTN2	12-75	0	0	1	0	0
STLC12	12-76	1	0	2	0	0
WSES3	9-85	1	0	0	0	0
PV123	1-86	0	0	2	0	1
TOTALS		7	0	20	0	2
GRAND SUM OF OBSERVATIONS				29		

Table C6-3: Root Cause Analysis - Quantitative Analysis - BWRs

ANALYSIS FOR RCA

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	1	0	0	0	0
DRES23	6-70	2	0	4	0	0
MLSTN1	3-71	2	0	0	0	0
VY1	11-72	1	0	0	0	0
PB23	7-74	0	0	0	0	0
COOPER1	7-74	2	1	12	0	0
DAEC1	2-75	0	0	6	0	2
FITZ1	7-75	1	0	2	0	0
HATCH12	12-75	1	0	2	0	0
LASLL	1-84	0	0	1	0	0
GRGLF1	7-85	0	0	2	0	0
LIM1	2-86	1	0	0	0	0
RIVBND1	6-86	2	0	5	0	0
HPCRK	12-86	0	0	1	0	1
CLPWST	4-87	0	0	1	0	0
PERRY1	11-87	5	0	0	0	1
FERMI2	1-88	2	0	5	0	0
TOTALS		20	1	41	0	4
GRAND SUM OF OBSERVATIONS				66		

Table C7-1: Prioritization - Quantitative Analysis
All 44 Plant Sites

ANALYSIS FOR PRA

PLANT	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	1	0	0	0	0
HADNCK	1-68	4	1	3	0	0
SONGS123	1-68	0	1	1	0	0
NMP1	12-69	0	0	0	0	0
DRES23	6-70	0	2	0	0	0
GINNA	7-70	2	1	0	0	0
HBRBSN	3-71	0	1	1	0	0
MLSTN1	3-71	1	1	0	0	0
PLSDS	12-71	1	3	0	0	0
VY1	11-72	1	0	0	0	0
SY12	12-72	0	0	0	0	0
MY1	12-72	1	0	0	0	0
FTCLHN1	9-73	0	0	0	0	0
ZION12	12-73	1	0	1	0	0
PRIEISL	12-73	2	1	0	0	0
COOPER1	7-74	0	0	0	0	0
PB23	7-74	2	0	0	0	0
IP2	8-74	2	0	0	0	0
ANO12	12-74	0	0	0	0	0
DAEC1	2-75	0	0	0	0	0
RANSECO1	4-75	1	1	3	0	0
CALCLFS	5-75	1	1	3	0	0
FITZ1	7-75	0	1	0	0	0
DCCK12	8-75	1	0	0	0	0
HATCH12	12-75	0	1	0	0	0
MLSTN2	12-75	1	0	0	0	0
IP3	8-76	0	0	0	0	0
STLC12	12-76	0	0	0	0	0
SLM12	6-77	1	0	0	0	0
NOANNA12	6-78	2	1	1	0	0
SQYH12	7-81	2	0	0	0	0
MCGUIRE	12-81	2	1	1	0	0
LASLL	1-84	0	2	0	0	0
GRGLF1	7-85	0	0	0	0	0
WSES3	9-85	0	0	0	0	0
PV123	1-86	1	0	0	0	0
LIM1	2-86	1	0	0	0	0
MLSTN3	4-86	1	0	0	0	0
RIVBND1	6-86	2	1	0	0	0
HPCRK	12-86	2	0	0	0	0
CLPWST	4-87	0	0	0	0	0
SH1	5-87	0	0	0	0	0
PERRY1	11-87	0	2	0	0	0
FERMI2	1-88	3	1	0	0	0
BDWD	7-88	1	4	0	0	0
SOTXS12	8-88	1	1	2	0	0
TOTALS		41	28	16	0	0

GRAND SUM OF OBSERVATIONS 85

Table C7-2: Prioritization - Quantitative Analysis - PWRs

ANALYSIS FOR PRA

WESTINGHOUSE	DATE	ATB	OBS	DFC	FLR	VLN
YKROWE	7-61	1	0	0	0	0
HADNCK	1-68	4	1	3	0	0
SONGS123	1-68	0	1	1	0	0
GINNA	7-70	2	1	0	0	0
HBRBSN	3-71	0	1	1	0	0
SY12	12-72	0	0	0	0	0
ZION12	12-73	1	0	1	0	0
PRIEISL	12-73	2	1	0	0	0
IP2	8-74	2	0	0	0	0
DCCK12	8-75	1	0	0	0	0
IP3	8-76	0	0	0	0	0
SLM12	6-77	1	0	0	0	0
NOANNA12	6-78	2	1	1	0	0
SQYH12	7-81	2	0	0	0	0
MCGUIRE	12-81	2	1	1	0	0
MLSTN3	4-86	1	0	0	0	0
SH1	5-87	0	0	0	0	0
BDWD	7-88	1	4	0	0	0
SOTXS12	8-88	1	1	2	0	0
TOTALS		23	12	10	0	0
GRAND SUM OF OBSERVATIONS				45		

ANALYSIS FOR PRA

CE AND B&W	DATE	ATB	OBS	DFC	FLR	VLN
SONGS123	1-68	0	1	1	0	0
PLSDS	12-71	1	3	0	0	0
MY1	12-72	1	0	0	0	0
FTCLHN1	9-73	0	0	0	0	0
ANO12	12-74	0	0	0	0	0
RANSECO1	4-75	1	1	3	0	0
CALCLFS	5-75	1	1	3	0	0
MLSTN2	12-75	1	0	0	0	0
STLC12	12-76	0	0	0	0	0
WSES3	9-85	0	0	0	0	0
PV123	1-86	1	0	0	0	0
TOTALS		6	6	7	0	0
GRAND SUM OF OBSERVATIONS				19		

Table C7-3: Prioritization - Quantitative Analysis - BWRs

ANALYSIS FOR PRA

GEN ELECTRIC	DATE	ATB	OBS	DFC	FLR	VLN
NMP1	12-69	0	0	0	0	0
DRES23	6-70	0	2	0	0	0
MLSTN1	3-71	1	1	0	0	0
VY1	11-72	1	0	0	0	0
PB23	7-74	2	0	0	0	0
COOPER1	7-74	0	0	0	0	0
DAEC1	2-75	0	0	0	0	0
FITZ1	7-75	0	1	0	0	0
HATCH12	12-75	0	1	0	0	0
LASLL	1-84	0	2	0	0	0
GRGLF1	7-85	0	0	0	0	0
LIM1	2-86	1	0	0	0	0
RIVBND1	6-86	2	1	0	0	0
HPCRK	12-86	2	0	0	0	0
CLPWST	4-87	0	0	0	0	0
PERRY1	11-87	0	2	0	0	0
FERMI2	1-88	3	1	0	0	0
TOTALS		12	11	0	0	0

GRAND SUM OF OBSERVATIONS 23

APPENDIX D

SPECIFIC EXAMPLES OF PROGRAMMATIC INSIGHTS FROM MAINTENANCE TEAM INSPECTION REPORTS

D.1 Specific Aging Management Insights

D.1.1 *Positive Aspects*

Among the positive responses by utilities to identifying aging concerns are the following:

- At Haddam Neck, plant aging and upgrade items were being identified and evaluated for future action. Recently completed upgrades include the reactor protection system (RPS) and the nuclear instrumentation system (NIS). In-core thermocouple, radiation monitoring and service water system (SWS) analysis were ongoing engineering projects.

- At Braidwood, management had instituted a program to return selected components to the respective supplier before failure for evaluation and analysis of wear, aging, and abnormal conditions.

- At Sequoyah, in response to NRC Information Notice 88-11[1] on the widespread failure of silicon bronze bolts used to splice bus bars in General Electric motor control centers (MCCS) caused by stress corrosion cracking, based on a sampling plan, the utility determined that such bolts did not exist in the MCCS and 480V switchgear.

- At Fermi, to verify that motor-operated valves (MOVS) fully open, another utility had originally planned to open them until an enlarged section of the stem contacted the mating seat in the bonnet, i.e. by "power backseating". However, such practices had resulted in broken stems and dropped disks at other plants. The utility has now eliminated power backseating by stopping all valves on the open stroke through the use of the limit switch, rather than the torque switch, so that the power is interrupted before the stem contacts the backseat. In some cases, the stem will coast into the backseat with considerable force. Through a vendor study, the utility concluded that the concern for backseating is restricted to large, "fast-acting" valves. Lacking evidence to the contrary, the NRC concluded that the practice of coast-in backseating could continue for the remaining MOVS.

- At Surry, in response to a catastrophic pipe rupture in main feedwater (MFW) piping, and NRC Generic Letter 89-08,[2] the inspectors credited the utility with having a well-defined program for erosion and corrosion thinning of feedwater piping.

- At St. Lucie, the utility had a preventive maintenance program to inspect and test the electrolytic capacitors in the 120 VAC inverters. The capacitors in the battery chargers were inspected but not tested. Electrolytic capacitors in 120 VAC inverters and battery chargers are used as smoothing filters for the output voltage and have been identified as having a limited life by the NPAR Program.[3] The utility agreed to periodically replace the capacitors for both the 120 VAC inverters and the battery chargers. The NRC cited the utility's actions as specific responses to NPAR recommendations.

- At Salem, as a result of severe deterioration of the Service Water System, i.e. through-wall leaks at weld joints in unlined carbon steel piping, microbiological corrosion of 316 stainless steel piping, lining deterioration due to abrasive erosion, and control valve cavitation, the Service Water piping will be replaced with 6% molybdenum stainless steel, lines will be rerouted to reduce turbulence, and stagnation areas will be eliminated. This effort was planned for completion by 1995.

- At Hatch, the utility was directly addressing aging concerns by replacing main feedwater system flow transmitters. Some actions involved replacing certain manufacturer's capacitors with more reliable ones.

D.1.2 *Negative Aspects*

Examples of premature wear of systems and components, lack of utility response to aging concerns are the following:

- At Duane Arnold, the manufacturer's instruction manual for the reactor water level switches did not specify any particular preventive maintenance requirements. However, in 1986, following a history of problems, the representative was called in and recommended that the switches be refurbished every 5 years. Although the switches had never been refurbished before that time, the utility took no action until 1988. This was cited as a violation.

- At the same plant, the response to a manufacturer's service advice letter issued in 1979 on premature wear of Tuf-LOC Teflon coated fiberglass sleeve bearings in certain types of GE 4160V circuit breakers was untimely. The affected components involved the Residual Heat Removal (RHR) pumps, Reactor Recirculation pumps and other safety-related breakers.

(1) The RHR pump circuit breakers were inspected in 1985 and replacement was recommended; however, they were not replaced until 1987.

(2) At the time of the MTI, only 6 of approximately 50 breakers had the bearings replaced. The remaining 44 breakers included 19 that were safety-related.

(3) Worn-out bearings were continuously identified; in one case, for a Reactor Recirculation pump breaker.

These examples were cited by the NRC as part of a violation. Similar failures attributed to worn bearings were identified at other plants.

- At Rancho Seco, the Auxiliary Feedwater System (AFWS) pump turbine governor and its mechanical overspeed trip both failed during a post-maintenance test, resulting in both trains of AFWS being pressurized beyond design stress values, making the system inoperable because of questionable piping integrity. This was cited as a violation by the NRC.

- At La Salle, the utility was very slow to respond to a 10CFR21 notification by Limitorque pertaining to common mode failure of melamine torque switches, of certain model types and serial numbers known to be installed at that plant. The cause of failure is post-mold shrinkage, which is affected by temperature and age. Specified actions included reviewing valve stroke times, conducting stroke time testing, and replacing switches. Five MOVS covered under NRC Bulletin 85-03[4,5] and other valves in a harsh environment had not been inspected for melamine torque switches. Also, thirty valves in one of the units had not been inspected in response to the NRC Generic Letter 88-07.[6] This was cited by the NRC as a violation of 10CFR50, Appendix B.

- Similar problems were noted at Prairie Island, where the utility failed to promptly inspect, correct, or justify continued operation of more than 25 Unit 1 and Unit 2 MOVs that were subject to the same common mode failure. The apparent cause of the untimely assessment was that the system engineers had too many responsibilities and the assessment was considered to be a "Low Priority" item. This was also cited by the NRC as a violation of 10CFR50, Appendix B.

- At Surry, compressed air is supplied by four, (two/unit) rotary water seal air compressors taking suction on the containment atmosphere, which is 99% relative humidity at 118°F, and then discharging into refrigeration air driers which are not capable of maintaining 35°F dew point even under optimum conditions. The utility's response to NRC Generic Letter 88-14[7] committed to conformance with ISA S7.3,[8] which states, in part, that at no time shall Instrument Air dewpoint exceed 35°F. In 1989, two of the discharge filters were so rotted, they could not be left in place. The remaining two filters were dirty but were left in place because spare filters were not on hand. There was no record that the Instrument Air drier filters had ever been changed since installation 7 years before.

- Also at Surry, chronic problems have occurred in the emergency diesel generator air start (EDGAS) system because of leaking check valves and compressors which have required frequent in-head replacement. The valves are no longer available for this vintage compressor. All six discharge check valves had recently been replaced and all six compressors were in the process of being replaced. The problems occurred primarily because of poor air quality. Water had accumulated on top of the check valves and entered the air compressors. Plant engineering personnel had expressed two concerns:

(1) There was no program for controlling or monitoring EDG starting air quality, and
(2) There was a high likelihood that all 18 air start receivers were full of rust and scale from years of wet service.

The NRC team witnessed the routine blowdown of the air start system for one of the emergency diesel generators, and a significant quantity of water was discharged. Poor air quality in the EDGAS can also affect the performance of the solenoid operated valves which admit air to the air starting motors. Sluggish performance of one of these valves had occurred on another EDG where station personnel recommended installing air driers and filters, with the intent of complying with ISA S7.3-75. In a related incident, over 20 lbs. of rust had recently been removed from inside the service air receiver in the turbine building. The NRC considered the utility's responsiveness to reflect more emphasis on short-term solutions rather than a commitment to long term corrective actions.

- At St. Lucie, following a manual reactor trip, both of the motor-operated valves (MOVS) for the motor-driven Auxiliary Feedwater pumps went fully open as intended. One valve was later closed by the operators and the other was throttled to 200 GPM flow rate. The operators later tried to reposition the latter valve, but it would not move. Also, the fully closed valve appeared as fully open on the control board in the control room. The throttled valve would not respond because the stem and nut were galled and seized together; thus it could not be manually positioned. The fully closed valve could not be remotely positioned open because the limit switch drive pinion gear had worn to the point that it was not meshed with the drive sleeve bevel gear. The limit switch was left indicating a "full open" signal to the control room and would only allow the Limitorque motor to rotate in the closing direction.

- Problems were noted at several plants concerning storage of components beyond their shelf life. In a few cases, problems were also noted with storage conditions, such as temperature and humidity control for Level "A" storage items.

- At Limerick, based on the experience of an older sister plant, it was determined that fouling of the Service Water System should not create serious problems until 14 years after initial operation. However, in the Essential Service Water piping supply of the compartment unit coolers of the High Pressure Coolant Injection (HPCI) pump, a 3" valve was found filled with soft, black sludge and 1/4"-1/2" of irregular scale buildup had occurred on an internal pipe wall. The problem was identified in 1985 as corrosion cell attack of carbon steel plus river silt. Chemical treatment was not applied to the spray pond which serves both the Essential Service Water and RHR Service Water systems. The damage to HPCI room coolers and the RHR pump seal coolers were of greatest concern.

- At Dresden, station technical staff reported that General Electric SBM switches used in 4160-VAC breakers and cubicles were at or near the end of life based on increased failure rates. SBM switches had not been included in the PM program and had not previously been inspected. Failures that occurred at other plants included the following: the alternate feeder breaker failed to close automatically after the normal feeder breaker was opened, and failures caused by hardened grease and dirt in stationary auxiliary "SBM" switch linkage within normal feeder breaker compartments.

D.2 Preventive Maintenance Insights

Examples from the MTI reports of insights related to preventive maintenance are noted below.

D.2.1 Preventive Maintenance Programs

- At Clinton and Perry, a 13-week "Rolling" maintenance schedule was used, which is repeated 4 times per year. At Clinton, whose program became a model for other nuclear plants, each week, a single division and approximately 19 systems, regardless of safety classification, were taken out of service for maintenance. At Perry, an equipment "group", which consists of equipment and/or systems that are taken out-of-service simultaneously, or may be taken out-of-service when any element is taken out-of-service, was scheduled each week.

  Any non-emergency maintenance was scheduled during the appropriate week along with surveillances and repetitive tasks. This scheduling minimizes operation of standby systems and the out-of-service time of safety related equipment.

- At D.C. Cook, a pilot program of Reliability Centered Maintenance (RCM) was begun. The systems selected were the Auxiliary Feedwater, the Main Feedwater, and the Service Water Systems. (However, a formal predictive maintenance program had not been established. Vibration analysis and oil sampling had begun and thermography was scheduled to start in the following year.)

- At Indian Point 3, an Important-to-Safety category of equipment had been defined for addition to the PM program. The program already includes the Condensate System, Heater Drain System, the Main Feedwater pumps, the Condensate Polisher System, the Main Steam Isolation Valves (MSIVs) and the Feedwater control valves.

- At San Onofre, the ratio of PM to corrective maintenance had increased steadily from 40% to 55% over the previous 2 and 1/2 years. At Zion, the PM hours to total maintenance hours averaged 46%, which was better than the 42% industry average. (PM may include both periodic and predictive maintenance).

- At Millstone 1, the Balance of Plant (BOP) equipment was not treated differently from safety-related equipment, as evident by the low BOP maintenance backlog. Also, in the plant reliability program, component operating performance, component integrity, and system design reliability were reviewed. The program involved equipment monitoring, root cause analysis, recommendations to prevent recurrence, and evaluating system design reliability.

- At Hope Creek, a reliability centered maintenance (RCM) program was being established to set a required reliability target for a specific function and associated components, and then adjust maintenance tasks and frequencies to achieve that goal. The RCM database would include the historical sequence of design changes to evaluate of their effects. The maintenance data base consists of plant systems, manufacturers' recommendations, plant experience, and surveillances required by Technical Specifications. Work orders for periodic recurring tasks such as PM were automatically generated by computer via the Managed Maintenance Information System (MMIS).

- At Calvert Cliffs, the NRC determined that the utility had performed a meaningful self- assessment of maintenance and initiated improved control, performance, and documentation of maintenance activities. The Electrical and I&C maintenance staff had a well-developed corrective and preventive maintenance program. Mechanical maintenance procedures were adequate but could be improved.

- At Cooper, approximately 85% of maintenance procedures were upgraded, improving content and format.

  At Dresden, the High Pressure Coolant Injection (HPCI) system was the model for the plant's Maintenance Improvement Program (MIP). The MIP included MOV upgrading, PM program enhancement, failure analysis, work planning preparation and scheduling, post maintenance testing, and communications. The HPCI system, as the "model" system, was enhanced by improvements in maintenance procedures, material condition, and overall appearance and performance.

D.2.2 Implementation of Preventive Maintenance

In this section, the focus is on the actual implementation and scope of maintenance, such as the procedures and work practices. Examples of timeliness of procedural revisions and quality and content of procedures will be given.

- At St. Lucie, many safety-related and nonsafety-related components did not have maintenance repair procedures, although many were under preparation. The components included Auxiliary Feedwater pumps, Containment Spray pumps, Turbine Cooling Water pumps, and Limitorque valve actuators. The vendor technical manuals were relied upon for corrective maintenance.

  Similarly, at Waterford, a newer PWR, there was only a generic procedure for corrective maintenance on safety and nonsafety-related pumps, compressors, fans, blowers, and other rotating equipment.

- Also at Waterford, three environmentally-qualified safety-related MOVs inside the reactor building were lubricated with a mixture of two different types of grease, contrary to the plant lubrication manual instructions, which specified only Exxon Nebula P-O type lubricant. High levels of lithium, a constituent of Mobil Mobilux EP-O, were found in the gearbox grease for those valves. The utility concluded that some mixing of lubricants in the main gear box had occurred. Although the utility had already corrected the identified problems, the NRC noted that weaknesses remained with the other aspects of the MOV lubrication program:

- The use of two different types of lubricants for the same component may lead to future occurrences of mixed greases for MOVs.

- The existing program provided conflicting guidance and did not ensure that future occurrences of mixing greases will not occur.

- Operations QA had not effectively identified that concern.

  Because mixing of greases can lead to actuator failure, this was cited by the NRC as a violation of plant Technical Specifications requiring compliance with Regulatory Guide 1.33[9] which, in turn, requires that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings.

- The following were also noted at Waterford:

  A work order for 4160 V switchgear to clean and inspect it required torquing of switches and exposed connections. However, an unauthorized deviation was noted in that "no loose bolts found (so) torque (was) not required." The NRC inspectors indicated the need to evaluate the safety significance and operability of the safety-related switchgear and the need to determine if torque requirements had been deleted in other safety-related switchgear. This finding was also cited by the NRC as a violation of Technical Specifications and of Regulatory Guide 1.33 which requires that general procedures be developed for control of maintenance, repair, replacement, and modification work.

  There was no preventive maintenance procedure for the nitrogen accumulator subsystems. Many safety-related systems depend solely on the nitrogen accumulators to operate critical valves during accident conditions. The utility was using a procedure for quarterly in-service valve tests which was intended to meet the ASME Boiler and Pressure Vessel Code Section XI[10], for 16 individual check valves associated with the safety-related boundary of the nitrogen accumulator subsystems.

- At Palisades, Neolube No. 1 lubricant was applied to gears and bolts of the Control Rod Drive Mechanism. Although this was the correct lubricant, no lubricant had been specifically identified in the Maintenance Work Order.

  Also, the insulation resistance (megger) test values of the motor for the Main Exhaust Fan to the plant stack was entered into the procedure data sheet more than an hour later by the maintenance personnel from memory.

- At North Anna, some plant procedures were not detailed enough to define the work steps to perform maintenance and testing activities, such as the Emergency Diesel Generator maintenance procedure, in which the removal of pistons was consolidated into a single step. The NRC was concerned that such lack of details could have led to significant performance variation and prevented accurate documentation of the work performed.

On the positive side, the following practices were noted:

- At Calvert Cliffs, if a procedure were found deficient, workers were instructed to obtain a procedure change before proceeding with the work. Although the interim effect slows down the work, in the long-term, better procedures and work control will result.

- At Braidwood, the staff was well trained, the work packages were well-prepared, some contained photos or diagrams, and the procedures were easy to use. Safety-related work was consistently well-documented.

- At Cooper, approximately 85% of maintenance procedures were upgraded improving content and format. Similarly, at Ginna, maintenance procedures were being revised as part of a major program for updating procedures to improve style, format, and content.

D.2.3 Scheduling of PM Activities

At several plants, the NRC noted that scheduled PM activities were often deferred for various reasons. Some examples are as follows:

- At Dresden, the maintenance procedure called for 4160VAC breakers to be inspected and overhauled every 5 years or 500 operations. However, at one of the units, breakers for two of the Containment Cooling Service Water pumps was overhauled in 1976. Breakers which were important to safety, i.e. required to satisfy technical specification requirements for two sources of offsite power to be available, were overhauled in 1973, 1975, and 1977. During the MTI, a 4160V feeder breaker failed to trip during an undervoltage surveillance test. The problem was a burnt trip coil caused by mechanical binding of the breaker mechanism, which was overhauled in 1976.

  A 4160V breaker for a Unit 2 LPCI pump tripped several times during pump starts in February 1988. The cause was a direct lack of lubrication on the trip latch roller mechanism, which would not have occurred if the breaker had been properly maintained.

  In addition, failure to perform PM had not been identified as a contributing factor in the failure of the Unit 3 Isolation Condenser Makeup Valve. Failure of the DC-powered MOV was caused by dirt and sticking auxiliary contacts with built up non-conductive deposits, resulting in increased electrical contact resistance. PM had not been performed on two Unit 3 250VDC Motor Control Centers (MCCs) since 1975. These MCCs supply power to torus suction valves of the HPCI system.

  Auxiliary switches, General Electric SBM type, for 4160VAC breakers and breaker cubicles had not been replaced even though the switches had a history of failure since 1982 and were at or near the end of life. These examples were cited by the NRC as a violation of 10CFR50, Appendix B.

- At Sequoyah, PM deferrals were not well controlled, and the justifications were often inadequate. The maintenance schedule did not show deferred or canceled PM tasks, so the determination of when the maintenance activity was last performed was difficult. Specifically, the PM for an Essential Raw Cooling Water (ERCW) pump had been deferred to a date past the mandatory PM performance point.

  The past PM program for safety related 6900V breakers was not well implemented, allowing 13 years to elapse between PM for some breakers. The record for non-safety related breakers is better. One-third of all breakers are maintained per outage. There is a reluctance to perform PM on incoming main circuit breakers because to remove a safety-related 6900V or 480V bus from service requires a Technical Specification Limiting Condition of Operation (LCO) Action Statement.

- Also at Sequoyah, the periodic change of dessicant for an auxiliary control air drier, which was scheduled annually, had not been performed since 1986.

- At Fitzpatrick, some PM tasks on MOVs had been deferred for more than one year, although there had been no deferrals of surveillance or EQ-related maintenance required by Technical Specifications.

- At Braidwood, several tasks on important Balance of Plant equipment, such as 345 KV switchyard breakers, had been well past their scheduled completion dates.

- At South Texas, the prioritization scheme for MOV preventive maintenance appeared to emphasize personnel availability rather than technical justification for PM deferral. Of 275 PM items, at least 28 pertained to safety-related MOVs, which were to be performed at 78-week frequencies involving the inspection, lubrication, and testing of the valves. At least 8 of the valves were containment isolation valves. The delays in PM ranged from 3 to 21 months.

D.2.4 Engineering and Technical Support

- At Maine Yankee, the NRC cited examples of poor engineering support, such as the replacement of a Fischer Porter Model B2496PB 0-800 in. W.C. range transmitter by a Rosemount Model 1151HP5E22B1 0-750 in. W.C. range transmitter. The transmitter is part of the Reactor Coolant Pump No. 3 seal water piping. Engineers were not involved in determining calibration set points.

- At St. Lucie, PM procedures were written by planners and were based on vendor manuals. There was no formal engineering review.

- At Sequoyah, the NRC felt that system engineers could have been more strongly involved in PM, particularly technical justification for deferment, and trending/failure analysis.

  Although the Maintenance Department had been regularly producing reports of component failures, the reports were terminated in 1989 because system engineers were not using them.

- At Rancho Seco, the NRC cited specific maintenance program weaknesses in communications, engineering support, support interfaces, post maintenance testing, procedure adequacy, electrical circuit breaker maintenance, and use of PRA.

- At Haddam Neck, engineers had both system and project assignments. Problems associated with the emergency diesel generator, the condensate system, and the auxiliary feedwater systems were all handled by the same engineer, leading to a delay in resolving problems with the emergency diesel generator.

- At Braidwood, for several surveillance tests of motor driven fire pumps, the motor current was recorded to be up to 6 amps below the minimum acceptable current of 40 amps, and the tests were accepted without an engineering evaluation. Approximately one year later, the utility did initiate an evaluation.

Some of the more positive examples of technical and engineering support are as follows:

- At Haddam Neck, corporate and engineering organizations incorporated preventive maintenance and spare parts recommendations in plant modifications. Plant engineers participated in the resolving technical issues related to repair or replacement of equipment. Review of regulatory documents was closely coordinated with plant maintenance.

  Specifically, corporate engineering had responded in a very timely manner to the failure of a Main Feedwater regulating valve, and to the significance of the loose parts which were involved.

- At Yankee Rowe, technical support of the maintenance process was effective, and engineers were integrated into the maintenance department to ensure such support, through an "Engineer of the Week" program, which assigns a corporate engineer is assigned weekly to maintenance. The engineer's duties include:

- Developing a critical component list.
- Identifying critical component failure modes.
- Troubleshooting maintenance problems.

- Improving procedures and practices.
- Assuring components are maintained within their design basis.

D.2.5 Preventive Maintenance of Mechanical Components

Some of the positive aspects of PM of mechanical components noted were the following:

- At Indian Point 2, in the beginning of the refueling outage (at the time of the MTI), the 12-year preventive maintenance recommended by the vendor technical manual was performed on one of the three emergency diesel generators. Based on the positive results of this very extensive disassembly, inspection, and refurbishment of the engine and generator, a reduced PM was performed on the remaining two diesel generators, rather than the annual inspection required by the Technical Specifications. All three diesel generators were under consideration for an increase in the total kW ratings, because of previously identified loading inadequacies. The increase in ratings could result in additional PM activities required.

- At Vermont Yankee, the emergency diesel generators were not barred over (turned or cranked with no intention to start) following a 3 minute run, contrary to the manufacturer's recommendations. The Technical Specifications required demonstrated operability following any action or event rendering a diesel generator inoperable. In response to NRC concerns, based on utility discussions with the manufacturer, an "air roll" after shutdown to enhance reliability and longevity will be adopted.

- At Millstone 1, six spare safety/relief valve (SRV) top works were available to change and test the entire complement of SRV top works at each refueling outage. This exceeded the technical specification requirements to test 50% of the SRVs at each refueling outage, and also exceeded the ASME Section XI requirements.

- Similarly, at Dresden, the NRC noted that at each unit's refueling outage, half of the safety/relief valve Automatic Depressurization System (ADS) are replaced with rebuilt and bench tested SRVs from the previous outage of the other unit. New pilot valves are installed in the ADS valves which were not replaced in the unit currently in an outage. The maintenance and test intervals are shorter than the vendor recommended minimum of 36 months.

- Also at Dresden, the overhaul program for all MOVs includes: a complete inspection; resistance testing of the motor; lubrication of the main gear case, limit switch compartment and valve stem; and proper setting of torque and limit switches. Permanently mounted sensors for measuring stem force have been installed on all safety related environmentally and non-environmentally qualified (EQ and non-EQ) MOVs. The utility anticipated better MOV performance and testing convenience from the Valve Operator Testing and Evaluation System (VOTES)* testing method.

- At Maine Yankee, a similar MOV overhaul program was in place. Approximately 100 MOVs are subjected to:

- Overhaul, PM, and lubrication inspection of Limitorque operations.
- EQ inspection of certain MOVs.
- Motor Operated Valve Analysis and Test System (MOVATS)* testing, torque switch replacement, and changeout of jumper wiring for certain MOVs.

- At St. Lucie, the utility installed high efficiency filters at the discharge of each instrument air drier. Sensitive I&C equipment, such as Bailey positioners and solenoid valves, were also equipped with upstream filter-regulators. However, there was no regular PM changeout schedule for replacing filter-regulator filter elements, and they are only changed when clogged.

- At H.B. Robinson, a Main Feedwater control valve was prepared to correct a flange leak by taking the plant off-line, rather than performing a temporary repair.

- At Fermi, the procedures for MOV assembly/reassembly and setting of switches were improved since previous inspections, were comprehensive, detailed and user friendly.

Some of the negative findings were as follows:

- At South Texas, the specification for "Control of Expendable Materials" required that Polyken No. 226 be the only tape used on stainless steel. However, the NRC observed the use of Nashua duct tape on the stainless steel seal internals of a reactor coolant pump, which comprise part of the reactor coolant pressure boundary. This finding was cited by the NRC as a violation of Technical Specifications requiring the development of and adherence to procedures for the maintenance of safety-related components.

- Also at South Texas, during the PM procedures for "78-Week Inspection, Lubrication and Test of the MOV Actuator for CCW to Charging Pumps Return Valve (MOV)", the NRC noted that the switch cover gasket of the limit switch/torque was totally compressed and hardened. Therefore, the switch compartment of the EQ classified MOV was not sealed. Also, the gasket was incorrect and supplemental holes had been punched in it so it would fit in the existing bolt pattern

- At Rancho Seco, proper preventive maintenance was not been established for the Auxiliary Feedwater governor and turbine overspeed device, and the governor oil-dump solenoid feature.

  Also, a work request for removal and detailed diagnostic inspection of the governor valve linkage did not contain acceptance criteria for critical measurements, neither min/max expected values, nor maximum measurement tolerances. This finding was cited by the NRC as a violation of 10CFR50, Appendix B.

- At Cooper, contrary to plant Quality Control procedures that were established to implement 10CFR50, Appendix B, maintenance was performed on an emergency diesel generator cam, which included critical reassembly steps, measurements and clearances, and verification of valve timing and timing clearances without QC inspection of these activities. This finding was cited by the NRC as a violation of 10CFR50 Appendix B.

- At H.B. Robinson, the NRC inspected check valves for the Low Head Safety Injection (LH-SI) and RHR Systems, the outlet check valves of the SI Accumulator, the discharge check valves of the Service Water booster pump, the Main Steam check valves, and the check valves of the MSIV Instrument Air Accumulator. The procedures lacked acceptance criteria for inspection of check valve internals for wear and degradation. Also, there was neither a surveillance nor PM program for these valves. Check valves were not tested or maintained unless the valve was in a degraded condition, or testing and/or disassembly was required by ASME Section XI.

- At River Bend, during the preventive maintenance of one of the MOVs, the as-found torque switch settings were 1.5 for the open and closed positions. The recommended settings were 1.75 minimum, 2.0 maximum. The procedure allows the setting to be below the minimum if:

  (1) the actual thrust data for the valve stem indicated the need to lower the torque switch setting, and

  (2) the design/field engineering staff reviewed the thrust data and approved the lower setting.

  However, there was no documentation showing that the lower setting had been approved.

- At Shearon Harris, the NRC noted that while the overall condition of the Instrument Air System was good, there were no formal PM, maintenance, operations, or surveillance procedures for the rotary screw air compressor, even though the compressor now supplies 100% of station air requirements. The vendor manuals called for regular PM of both the compressor and the air drier.

D.2.6 Preventive Maintenance of Electrical and I&C Components

- At McGuire, fuel cycles are every 14 months. Each circuit breaker receives a contact resistance (Doble) test and preventive maintenance every third refueling outage. The maintenance program was consistent with good industry practice, however, control wiring compartments and bus compartments in the switchgear were not being inspected.

No significant problems were identified in the maintenance of 125 VDC batteries, battery chargers, circuit breakers, and 120 VAC inverters, including those for the emergency diesel generators. In response to a failure of the output capacitors of an inverter, the utility now had a PM program to replace those capacitors for all inverters and batteries.

- At Shearon Harris, the procedures included nearly all of the 30 steps typically recommended for medium voltage switchgear. The exceptions were a check of the anti-pump circuit, and an insulation resistance measurement across the open contacts.

  The PM program called for performing preventive maintenance at every second refueling outage, or servicing approximately half of the switchgear at each refueling outage. A small percentage of the circuit breakers can be conveniently serviced biannually while the unit is at power.

- At Dresden, the NRC noted that there had been a strong program to resolve problems with 4160 VAC breaker Tuf-Loc bushings.

- At Maine Yankee, there was a major ongoing project to upgrade eighty-three 480V circuit breakers, mostly GE Model AK 25, and correct difficulties in calibrating the electro-mechanical overcurrent trip devices. Following an unplanned reactor trip from 98% power, a trip of this service water pump was attributed to failure of the electro-mechanical overcurrent trip device in the circuit breaker of the pump motor. The circuit breaker upgrade includes:

(1) Disassembling the breaker to clean, inspect and lubricate parts.
(2) Replacing worn, damaged, or superseded parts with new ones.
(3) Installing a new latch roller assembly and trip shaft bearing.
(4) Installing a solid-state overcurrent trip device to replace the previous electro-mechanical device.
(5) Setting and verifying the sensor tap selection ratings and adjustable trip settings.
(6) Performing a mechanical and electrical check-out, and functional testing.

Also, for cables which overheat during a battery charger inspection, neoprene-insulated cable is to replace existing rubber-insulated cable.

- At Perry, the NRC reviewed actions taken in response to the loss of fill fluid defect identified by the Rosemount 10 CFR 21 notification of February 7, 1989. The utility identified 277 Rosemount transmitters within the scope of the notification. Individual computerized trend records showed the results of all calibrations, including as-found and as-left data. The data were analyzed and evaluated as recommended by the vendor. Only three failures had been detected due to loss of oil. The utility was an active participant in the BWR Owner's Group on Rosemount failures. Plant operators had been trained on the transmitter failure symptoms. The NRC concluded that the actions taken in response to the notification had been excellent.

- At Calvert Cliffs, the NRC noted that the PM on 480V breakers, protective relaying on the logic circuits and battery systems of the emergency diesel generator was performed satisfactorily.

- At Sequoyah, the PM procedure for 6900 V switchgear included nearly all steps recognized by industry as beneficial, and its overall clarity and content were excellent. The procedure contained about 38 independent verification steps, and it invoked a special procedure aimed at reducing common mode failure caused by maintenance.

  However, the procedure omitted several accepted industry practices, such as the mention of the anti-pump circuit, space heaters, blow out coil, and potential transformer compartments. Also, lubrication requirements were not clearly addressed.

Among the negative findings are the following:

- At Hatch, the procedure specifying preventive maintenance for 4160 VAC metal-clad switchgear covered verification of undervoltage trip attachments (UVTA), breaker cleaning and inspection (with the breaker removed), cell cleaning and inspection, and relay/control wiring compartment cleaning and inspection. The PM schedule was as follows:

- Every 18 months for UVTAs.
- Every 60 months for four Unit 2 line-ups required by Technical Specifications which are related to containment penetration overcurrent protection.
- Every 60 months for all other switchgear.

Specific details which were specified by the vendor, Westinghouse, but which were omitted by the utility for circuit breakers were as follows:

- Inspecting current carrying parts for overheating.
- Checking the breaker for binding or friction.
- Inspecting the primary contacts for binding or pitting.
- Inspecting the arcing contacts for uneven wear or damage.
- Verifying 6 contact dimensions.

For the stored energy mechanism, Westinghouse recommended:

- Removing the spring charging motor brushes for inspection of length.
- Inspecting the motor support for loose or missing bolts, as per NRC Information Notice 88-42.[11]

The utility's program did not include inspection and insulation resistance measurement of the switchgear bus, nor inspection of the outgoing cable compartment or potential transformer compartment. However, thermographic imaging of the outgoing cable termination was included in the predictive maintenance program.

The NRC questioned the 60 month maintenance interval, as opposed to the 12 month interval recommended by Westinghouse. Deviations from the vendor recommendations were not properly analyzed or documented. Four failures of 4160 V switchgear were reported by all utilities to NPRDS for 1987 and 1988. Five out of five nuclear plants surveyed by the utility used a PM interval greater than 12 months.

The NRC cited this finding as a violation of 10CFR50, Appendix B, in that the procedure did not provide for incorporate of vendor recommendations into the maintenance procedures, or alternatively, a documented evaluation of why the vendor recommendations were not appropriate.

It was also noted that the electrical PM program did not include:

- Protective trip testing of molded case circuit breakers, other than containment penetration circuit breakers.
- Periodic visual inspection of 4160V current limiting reactors.

- At Vermont Yankee, a rated load discharge test is conducted once each operating cycle on 125V batteries, as per the Technical Specifications. IEEE Standard 450-1980[12] recommends testing every 5 years, while the manufacturer recommends no testing. The NRC expressed concern over possible detrimental effects due to excessive testing, therefore the utility proposed a change in Technical Specifications to demonstrate battery operability by a service test, which duplicates the specified emergency load profile, every or alternate refueling outage, while the performance test is conducted every 5 years.

- At Dresden, the Emergency Diesel Generators 2,3, and 2/3 excitation field breakers and reactor protection system breakers were not included in the preventive maintenance program.

- At St. Lucie, during walkdown inspections of the 120 VAC inverters, 125 VDC battery chargers, 120 VAC vital instrumentation power panels, the main control panel in the control room, and other electrical and I&C panels, it was noted that numerous fuses and fuse holders were corroded (tarnished). The corrosion was not excessive, but unexpected. The concern was that the corrosion could be a potential problem in the electrical circuits. Previously, several control room fuses had to be cleaned due to tarnishing. The utility agreed to upgrade PM procedures to consider potential fuse corrosion.

- In 1985, several plants, including Clinton, experienced an excessive number of failures of 345 KV switchyard type GHO SF6 breakers manufactured by Siemens Allis, Inc (SAI). Although not safety-related, these breakers provide offsite electrical power. In 1985, SAI recommended a four-phase PM program and a routine maintenance inspection schedule. The program involved checking all breaker adjustments, monitoring performance, periodically providing feedback data to the vendor and routine annual maintenance. At Clinton, in 1988 and 1989, two such breakers indicated:

(1) Excessive compressor operating time, which indicates SF6 gas leakage.
(2) Several components, such as numerous blast valve and moving main contacts, failed to operate and required replacement.
(3) Various adjustments were made to meet vendor acceptance criteria.

The NRC concern was that, although the utility aggressively contacted the vendor for technical advice and direction, there appeared to be a lack of management initiative in incorporating vendor recommended maintenance on the breakers for four years.

Also, in August 1987, an SAI service bulletin identified a problem with 345 KV trip coil circuits on LPO type breakers. A resistor failed during operation because of slow opening of the auxiliary contacts. It was recommended that the trip circuit be energized and checked. The NRC determined that preventive maintenance had never been performed on Clinton's LPO breaker 4522, which supplied offsite power.

The NRC checked the utility's response to industry recommendations that vendor-supplied torque values be periodically verified for bolted connections on 480V, 4160V, and 6900V bus connections and that this activity be included in the existing PM program. The NRC was concerned about an untimely response at Clinton in implementing a pilot thermography program for 460V and 6900V components.

However, for the overall PM program for electrical components at Clinton, the NRC reviewed various safety related and balance of plant components to determine which ones were included. No concerns were identified other than the one for the 345kV breakers.

- At Indian Point 2, the NRC witnessed the 18 month PM inspection on a Westinghouse Type DB-50 reactor trip breaker, performed by both Westinghouse and plant maintenance personnel. The NRC was concerned because several breakers were left uncovered for lengthy periods after removal from their cubicles, which was contrary to Westinghouse recommendations and utility procedures.

- At H.B. Robinson, PM is performed on all safety related switchgear at each refueling outage, which the NRC considered to be a conservative interval. The NRC's review of 480V safety related switchgear concluded that there had been 5 maintenance-related failures in 18 months. This was a rate of 0.11 failures per breaker-year, which was significantly higher than the IEEE Standard 493-1980[13] rate of 0.0027 failures per unit year, suggesting ineffective maintenance.

Also, the PM procedures for electrical equipment were weak, and there was extensive use of a very simple checklist. The NRC considered the PM procedure for safety-related and Dedicated Shutdown System switchgear to be poor because, for example, it did not describe how to check critical dimensions of primary contacts, nor state how to adjust them. It did not specify operating the breaker electrically from the test stand, checking charging motor brushes, nor open/close response time nor contact resistance measurements. Only a very brief checklist was used for PM of 4160 V switchgear. The NRC considered the lack of instructional detail to increase the possibility of unplanned actions and unsatisfactory maintenance and equipment failures.

D.2.7 External Technical Requirements (NRC, Vendor, INPO) and Control of Vendor Information

Some of the positive findings regarding external technical requirements such as NRC, vendor, and INPO are as follows:

- At Surry, the NRC noted that the vendor manual control program was well documented.

- At San Onofre, a multi-unit site, the PM program for each of the approximately **147,000 components** was being evaluated against the manufacturer's recommendations. The approval of the Cognizant Engineer was required for any deviations. Also, all of the approximately **28,000** vendor technical manuals were being updated and verified.

- At Waterford, the PM program for motor-operated valves included both safety-related and balance of plant valves. The program was significantly above the industry norm. The PM requirements also conformed to the recommendations of the vendor technical manuals and to industry good practice.

- At Grand Gulf, problems were noted in responding to NRC Notices, mainly due to miscommunications among different groups concerning the due dates. However, administrative procedures were revised to provide for more stringent and aggressive closeout of NRC Notice evaluations.

  Also, the NRC noted that each vendor manual had a list of maintenance documents. When a revision or change to the manual was received, the Document Control group notified the preparer so that changes could be made to the document if necessary. This procedure ensured that all affected documents were controlled, reviewed, and updated.

- At Ginna, the NRC noted that procedures existed which defined conditions adverse to quality which merit review. The conditions can be identified in NRC Bulletins and Generic Letters, INPO Significant Operating Event Reports, 10 CFR 21 reportable items, Class 1E electrical age-related failures, and component or procedural deficiencies.

  Also, controlled vendor manuals were used for maintenance activities which became part of the work packages. Vendor manuals were upgraded.

- At McGuire, the NRC concluded that the utility had a good program to respond to industry and NRC-identified problems. The computer tracking system worked well and documentation was satisfactory. The utility responded to most industry issues, but not all in a timely manner.

- At Prairie Island, PM requirements for equipment appeared to be adequately addressed. Vendor recommendations were included in the PM program, or deviations were technically justified.

  The NRC noted similar findings at other plants such as Braidwood, Yankee Rowe, Haddam Neck, and Fermi.

- At Sequoyah, the recommendations from NRC Information Notice 87-61[14,15] on W-2 cell switches in 480V switchgear were incorporated into PM procedures. Ferroresonance in high-voltage transformers, as indicated in NRC Information Notice 88-60,[16] was correctly addressed.

  Also, based upon a review of five vendor manuals involving valves, traveling screens, strainers, pumps, and compressors, the NRC determined that the manuals were being controlled, updated, and used in preventive maintenance.

- At River Bend, the utility effectively incorporated vendor manuals to ascertain the maintenance requirements for each component located in the Penetration Valve Leakage Control System (PVLCS) and the Automatic Depressurization System (ADS). The vendor recommendations compared adequately to the EQ maintenance and surveillance requirements for the two systems.

Among the negative findings in these areas are the following:

- At D.C. Cook, the vendor manual for the Auxiliary Feedwater pump required that the pump packing be adjusted (for a controlled amount of leakage) while the pump is operating. This requirement was not incorporated into the

AFW pump maintenance procedures. Although no problems were noted, the NRC considered that rotor seizure, scored shaft sleeves, or burned packing could have resulted. This finding was cited by the NRC as a violation of 10 CFR 50, Appendix B.

- At Shearon Harris, the Vendor's recommendations for Essential Service Water pumps for 6-month maintenance concerning checking of shaft alignment, motor vibration and shaft packing, as well as 2-year maintenance concerning shaft alignment and concentricity checks and bearing, sleeve, and wear ring replacement was not adopted. Furthermore, there was no formal justification for not following the vendor's recommendations.

- At Palo Verde, there was an extensive backlog in the review of the Service Information Letters (SILs) issued by the Emergency Diesel Generator manufacturer, Cooper Industries. Only 3 out of 19 SILs were formally evaluated. However, control of vendor information was being upgraded.

- At Salem, a cylinder head for an Emergency Diesel Generator was removed without using a special lifting ring, designed to accommodate the non-vertical angle, as identified in the technical manual. Also, chapters were missing for the injectors, valve gear, exhaust and intake manifolds, and jacket water connections, which would have shown the torquing and clearance specifications.

- At Duane Arnold, as a result of a Safety System Functional Inspection of the High Pressure Coolant Injection (HPCI) System initiated by the utility, the NRC noted that vendors' recommendations were inconsistently incorporated, including maintenance and testing. Technical justifications for not incorporating the recommendations was not provided.

- At Zion, the NRC noted that there was a failure to incorporate vendor recommendations into the procedures. The Vendor Manuals were to be updated by mid-1991, to ensure that no unreviewed Equipment Technical Information is used. The categories of the procedures are safety-related, regulatory-related, reliability-related, and other. The information sources are: vendor manuals, bulletins and notices, NRC Generic Letters and 10 CFR 21 notifications, station experience and industry sources. One hundred fifty out of three thousand manuals were updated. Approximately forty-five thousand components and equipment will be included. The NRC noted that the PM program did not verify the incorporation of vendor recommendations or justify changes to recommendations.

- At Fort Calhoun, the calibration procedure for the Main Feedwater Regulating System required the use of vendor manuals, but manuals were unavailable or that were available were inadequate. Also, some unverified, non safety-related manuals, which were not scheduled to be verified, were in use by I&C maintenance personnel.

- At Vermont Yankee, there was no effective means to update manuals, even though some manufacturers provided an approved procedure that specified the process for controlling formal revisions of their manuals. Old customers did not consistently receive revisions and sometimes the revisions were received from other utilities. Also, some manufacturers' information was retained in uncontrolled files. The maintenance supervisory staff reviewed and updated the vendor manuals, but the process was informal and inefficient. However, the appropriate technical manuals for battery and emergency diesel generator were used during maintenance activities.

- At Maine Yankee, there was no administrative control procedure to identify the vendor manual for instruments having the same model number but different manufacturing dates. Thus, it was possible for the staff to use the wrong manual.

  In general, the NRC determined that Maine Yankee maintains a good program to control maintenance vendor technical manuals. However, there was a potential for new manuals purchased by an individual not to be incorporated into the system.

- At St. Lucie, the vendor for the new Instrument Air System compressors recommended retorquing the crosshead bolts after 6 months or 2000 hours of operation. This requirement was not addressed in the PM procedure, nor was any justification given for not torquing the bolts. The Unit 1 compressors, therefore, were nine months late in being torqued.

- At Clinton, as a result of review of selected systems, significant differences were noted between existing surveillance and PM requirements and those noted for the hydraulic actuators for the Reactor Recirculating Flow Control Valve. An abbreviated analysis of the hydraulic system showed that many of the vendor recommendations were excessive but some key tasks, not currently performed, should be. The recommendations included vibration and oil analysis, changes to operator round sheets, trending of surveillance data, additional PMs to replace the critical full flow filter element, and additional or expanded I&C and electrical PM tasks.

  In general, the utility's incorporation of outside sources such as vendor service information and advisory letters (SILs and SALs), INPO Operation and Maintenance Reminders (O&MRs), Significant Event Reports (SERs), and NRC Bulletins, Notices, Generic Letters and other correspondence was systematic. However, outside source documents were arbitrarily designated "Routine", i.e. as activities which will not directly affect plant operations adversely without a prioritization review. Engineering response due dates were easily extended. This extension could have delayed implementation of corrective actions.

- At Indian Point 2, the NRC cited specific examples where the utility did not properly consider important vendor recommendations, such as the following:

(1) For the containment hydrogen concentration monitor, the manufacturer recommended an annual pressure test and a 5-year gasket and diaphragm changeout. The manufacturer was performing the annual pressure test as part of contracted PM, although the utility was unaware of the requirement.

(2) For the containment high range radiation monitor, the manufacturer recommended a capacitor changeout every 2 years and factory recalibration every 5 years. Another manufacturer recommended semiannual chopper calibration and periodic slidewire cleaning.

  The NRC concluded that the utility had no formal process to review such vendor recommendations, and also that the utility's I&C maintenance program was weak in that it lacked a formalized, well documented basis for calibration procedures, which resulted in incomplete surveillances and uncertainty about the adequacy of certain calibration acceptance criteria.

- At Perry, the NRC concluded that applicable items from external operating experience reports were factored into the maintenance program. Such reports included:

(1) Limitorque 10 CFR 21 report, dated November 3, 1988, on Melamine torque switches.

(2) The following NRC Information Notices:

- IN 89-07,[17] on failure of small diameter tubing (air, fuel, oil) on emergency diesel generators resulting in inoperable diesels.

- IN 89-76,[18] on bio-fouling of Zebra mussels.

- IN 90-11,[19] on maintenance deficiencies associated with solenoid operated valves.

- IN 90-37,[20] on sheared pinion gear-to-shaft keys on Limitorque motor actuators.

- IN 90-52,[21] on retention of broken Charpy specimens.

- At Rancho Seco, the vendor manuals for the turbine governor of the Auxiliary Feedwater pump did not reflect the as-built conditions. Also, the maintenance test procedures did not incorporate NRC Lessons Learned on turbine controls and protection failure modes.

- At H.B. Robinson, the NRC reviewed manufacturers' PM recommendations for approximately 10 components in the HVAC system. In three cases, lubrication and cleaning recommendations were not incorporated into the PM procedures. The components included motors on non-safety-related air handling units, safety-related evaporative air coolers, and safety-related, side-mounted pneumatic louver positioners. Lubrication recommendations were also ignored for booster pumps of the Service Water System and various HVAC components, such as bearings, motors, and centrifugal and axial fans.

- At North Anna, the NRC determined that most information requiring the utility's response did not necessarily pass through Licensing, so there was a high probability that such information may not have been received by the responsible department and acted upon. An example concerned Reactor Coolant pumps and motors and Auxiliary Feedwater pumps, where the vendor manual pertained to ball bearings, not the sleeve bearings actually installed.

  Specifically, the NRC was concerned that incorporation of vendor technical information for the Service Water System into plant procedures and activities was potentially inadequate. There was an excessive delay and essentially no actions were taken to implement this item.

  Also, PM performed on a spare motor of the Reactor Coolant pump did not include Westinghouse recommendations that the motor shaft be turned periodically to prevent babbitt bearing damage. Also, provisions to initiate the oil lift system and recommendations that the internal space heaters be connected and energized were not included in the PM requirements.

- At South Texas, a procedure for "Limitorque MOV Motor Inspection and Lube" did not refer to staking the motor pinion gear/motor shaft key and/or set screw. Two field change requests dealing with the proper material for the key and key staking were incorporated into the vendor technical manual, but not into the procedure.

- At Cooper, the NRC considered the process for design and configuration control of vendor technical information to be weak. Specifically, the NRC noted excessive grease leakage from the shaft coupling of the HPCI turbine-pump. Incorrect vendor instructions were used. Management was unable to determine the root cause of the incorrect information and conclude whether this affected other components.

  Also, the controlled copy of vendor instructions containing the torque values for Anchor Darling valves was incomplete. This led to a failure to torque the body-bonnet studs on a containment isolation valve after repair. No centralized policy or guidelines existed for torquing threaded fasteners.

- At River Bend, maintenance work orders referred to procedures and the vendors' manuals, but the references were not specific. The vendor manuals contained many sections not applicable to the task, and applicable sections of references to procedures were seldom specified in any of the work plans. In general, the level of detail was poor.

D.3 Predictive Maintenance and Condition Monitoring Insights

Some of the specific positive and negative findings that were identified in the MTI reports are as follows:

D.3.1 Positive Aspects

- At River Bend, approximately 300 safety systems and important to reliability system components were being monitored under the vibration program. Spectral data, wave forms, and trends were taken for each point monitored. Reports of adverse trends were subsequently distributed to system engineers, and maintenance and operations personnel. Degraded rotating equipment such as a motor bearing for a circulating water pump and an alignment problem with a speed increaser for a main feedwater (MFW) pump were identified.

- The lubricating and transformer insulating oils are monitored under the oil analysis program. Forty-six lubricating oil components and thirty-one transformers (insulating oil) were being monitored. The results were trended and reports of adverse trends distributed to personnel. An analysis of dissolved gas of the preferred station transformer showed there was acetylene in excess of the alert limit, which meant that electrical arcing was occurring within the transformer. The transformer was subsequently replaced during that outage.

- Also, the utility was developing an acoustical emission monitoring (AEM) program as part of the predictive maintenance program for check valves. The utility was working with the Electric Power Research Institute (EPRI) and other utilities to evaluate degraded check valve performance in the laboratory using the AEM program. Any valves identified as degraded or inoperable by the AEM program would be disassembled and inspected during the next outage.

- At St. Lucie, an older PWR, vibration data trending identified the main feedwater (MFW) pump to be degraded, and repairs were accomplished during power operation, thereby preventing a possible plant trip and challenge to safety systems. Thermographic analysis identified a degraded positive output connection on a safety-related battery charger. The charger was removed from service and repaired without affecting the plant's safety systems. Thermography also identified isophase jumpers which had a high resistance electrical connection. Corrective actions were taken to prevent damage to plant equipment.

- The micro-electronic surveillance and calibration (MESAC) system was designed and developed at the Braidwood station to dynamically test instrument systems. MESAC injects continuous test signals that simulate design basis inputs, while simultaneously recording the dynamic response of the instrument system and comparing the data with expected values. No lifted leads or jumpers are required, thereby significantly reducing the risk of unplanned reactor trips, as commonly occurs with the standard practice of discrete static testing. The NRC considered MESAC a significant strength.

- At Haddam Neck, several actions were taken in response to NRC Information Notice 88-24,[22] on failure of air-operated valves affecting safety-related systems. These actions included the replacement of several solenoid valves used for containment isolation. In response to NRC Generic Letter 88-14, the utility tested all safety-related air-operated valves to verify that they fail in the required safe position following loss of air supply. Maintenance was instituted for boundary components, such as pressure regulators between the air supply system and the safety-related components, and a procedure to detect contaminants was implemented.

- At San Onofre:

- The Acoustical Valve Leak Detection Program is regularly applied to secondary side valves of the plant. There were plans also to apply it to primary side valves.

- The Thermal Shield Movement Monitoring Program assesses neutron flux to detect thermal shield (reactor vessel internals) motion or movement. Loose parts were monitored using an accelerometer attached to the reactor vessel.

- The Rotating Equipment Vibration Monitoring Program monitors and trends vibration of main station turbines, main feed pump turbines, circulating water and condensate pumps, and stator water pumps. The plant received a state-of-the-art "Schenck" rotor-balancing machine of 550,000 lb. at hard bearing slow speed.

- At Waterford, there is an impressive trending and predictive maintenance program. All safety-related and most BOP mechanical components are included in the vibration monitoring program. Other items trended include flow rates, pressures, temperatures, and instrument setpoint drift. Special software allows meaningful use of trending data.

- At Perry, as a result of incidents in 1987 of Main Steam Isolation Valves (MSIVs) failing to close, the utility committed to the NRC to install temporary temperature elements near the ASCO dual solenoids, and on the solenoids and the valve bodies themselves, in both the steam tunnel and drywell. Historical readings of the permanent steam tunnel and drywell temperature elements near the MSIVs were also evaluated. An operability test for the ASCO dual solenoid and a quarterly fast closure time test were also performed monthly. The temporary temperature monitoring and special testing were discontinued in 1989, based on the results of a thermal endurance test program, and to prevent unnecessary wear of the MSIV poppet and seating surface. The NRC inspectors evaluated the temporary temperature monitoring and the special testing, and noted no elevated trends or valve stroke failures. Approximately 20 maintenance work orders were reviewed to determine the maintenance history on the MSIVs for the previous 2 years. No anomalies were identified that could be considered as contributing to the MSIV closure function failure.

- At Salem, the Service Water piping was monitored by inspecting carbon steel liner and weld repairs. Three material test loops are installed in the system monitoring different conditions of flow, as well as ambient stagnant and heated stagnant water.

D.3.2 Deficiencies

- At D.C. Cook, an older PWR, the utility's analysis of the February 1989 failure during testing of two safety-related 4kV breakers to close on demand due to lubrication hardening did not specify corrective action to prevent recurrence. No action was taken to inspect other 4kV breakers for common mode failure. Consequently, in March and April of 1989, seven additional safety related and balance of plant breakers failed to close during testing. These failures also were caused by hardening of the lubricant on the breaker linkage. This finding was cited by the NRC as a violation of 10 CFR 50, Appendix B.

- At Zion, the turbine alert and action vibration limits of the auxiliary feedwater (AFW) pump were set at 5.91 mils and 10.61 mils peak-to-peak, respectively. These limits were derived from a Canadian government specification for small turbines. The vendor manual recommended 3 mils and 5 mils peak-to-peak, respectively. A vendor bulletin recommended testing the overspeed governor once per week. The moving parts of the trip and throttle valve should be lubricated once per week, and all moving parts should be kept clean. Contrary to these recommendations, at one unit, the overspeed mechanism was never tested, and at the other unit, the mechanism was tested once, with limited success, approximately 2 years before the NRC inspection and approximately 17 years after pump installation. This finding was cited as a violation by the NRC.

- At Fort Calhoun, another older PWR, the surveillance test procedure for Auxiliary Feedwater (AFW) pumps did not include all of the requirements of ASME B&PV Code Section XI, Subsection IWP, Table IWP-3100, so that the tests were not repeatable and were not accurate to determine pump operability.

  Also, the HPSI pumps were tested using the minimum flow recirculation path but no flow measurements were required. The utility committed to test the pumps at near rated flow and measure the flow rate for future inservice testing. In addition, the surveillance test procedure for Safety Injection valves was not in conformance with the ASME Code, Section XI. Two different stroke times were measured: a local stroke time and a light-to-light stroke time. The latter is less accurate, especially for air-operated valves, but was always used to compare to the acceptance criteria.

- At Hatch, a predictive maintenance procedure described a method to obtain and analyze vibration analysis data to detect incipient equipment failure. The method did not interface with Technical Specification requirements and did not necessarily require that a maintenance work order be issued to correct any deficiencies. The NRC was concerned that if a safety related component were being tested and vibrations exceeded the limits of ASME Code Section XI, Subsection IWP, Table IWP-3100-2, the procedure did not require linkage to the Code, so that Code requirements may not be satisfied.

- At Dresden, the lubrication program required that oil samples be trended. However, of 21 components requiring oil sampling, only 14 samples were trended, without justification for those not trended. Oil for the diesel fuel day tanks was not trended, because new oil was analyzed before use in the diesel system. Although oil samples were plotted, a formal report was not issued with an evaluation of the samples. Corrective actions such as oil changes appear to be isolated cases, rather than implementation of a fully developed and comprehensive trending program. No acceptance criteria were developed for adverse trends or correlating sampling data to significant events such as an oil change, filtering old oil, equipment run time, or equipment availability due to unscheduled maintenance. Despite the foregoing, no equipment failures caused by oil degradation were identified during the inspection.

- At Hope Creek, oil samples from the emergency diesel generator were taken from a stopped engine, downstream from a filter, rather than from a running engine before any filtration.

- At St. Lucie, no testing of molded case circuit breakers, which are protective devices and disconnects in the safety-related 125 VDC System, were not tested.

  Similar problems were noted at Shearon Harris, a newer PWR, where such breakers were not tested, despite the availability of the vendor's field test procedure, pending further evaluation by the utility.

- At Waterford, improper torque switch settings resulted in overthrusting conditions for some MOV actuators and valve stems. Several defective torque switches were noted. These failures comprised 25% of the small sample of 20 MOVS examined by the NRC for compliance with NRC Bulletin 85-03. Only eight additional MOVS were tested at the subsequent refueling outage, by means of the MOVATS leaving about 65% of the safety-related MOVS untested.

- At the same plant, one of the high pressure safety injection (HPSI) pumps ran during a surveillance test with a recirculation flow of only 19 GPM versus 25 GPM recommended in the vendor manual. The manual stated that the recirculation line must be kept open when starting or stopping during light load, or else failure to provide minimum flow can cause the rotor to seize and damage the internal parts. It was also noted that contrary to the ASME Code, Section XI, Subsection IWP, Table IWP-3100-2, the recirculation flow data sheet did not contain or identify any value associated with an "Acceptable", "Alert", or "Required Action Range" for recirculation flow. The test data revealed that recirculation varied by as much as 25% from the nominal 25 GPM, and either the higher or lower limits would have been exceeded, yet the pump was never declared inoperable. The pump's inboard and outboard thrust bearings later required replacement because of roughness and excessive play.

- At H.B. Robinson, the NRC inspected check valves for the Low Head Safety Injection and RHR systems, the check valves of the Safety Injection Accumulator, the check valves of the Service Water booster pump discharge, the Main Streamline check valves, and the Instrument Air Accumulator check valves of the Main Steam Isolation Valve. The procedures lacked acceptance criteria for inspection of check valve internals for wear and degradation. Also, there was neither a surveillance nor a PM program for these valves. Check valves were neither tested nor maintained unless the valve was in a degraded condition, or testing and disassembly was required by ASME Code, Section XI.

- Also at H.B. Robinson, the NRC compared the IEEE Maintenance Good Practices for Nuclear Power Plant Electrical Equipment[23] (IEEE 89TH0248-5-PWR) to the practices implemented on the motors for a Service Water pump, a Service Water booster pump, and a Safety Injection pump. Approximately one-half of the practices were not implemented by the utility, such as power or current monitoring, winding temperature monitoring, bearing temperature monitoring, and thermography. Space heaters were not being checked. There was no inspection or trending of Safety Injection pump motors. However, insulation and winding resistance checks at refueling and vibration monitoring were being performed.

- At McGuire, loss-of-air tests had not been conducted for some of the Main Steam Isolation Valves at both units since preoperational testing. Also, testing of MSIV accumulator check valves had not been completed or planned.

- At Prairie Island, the Atmospheric Steam Dump Valves could not be fully opened during some positioned checks. Similar problems were encountered previously, but not considered unacceptable. However, an engineering evaluation determined the "as found" results to be unacceptable.

D.4 Post Maintenance Testing

D.4.1 Positive Aspects

Specific insights from the MTI reports were:

- At Shearon Harris, PMT requirements were detailed in a special PMT Guide, which was then used by the planners in assigning PMT requirements in the maintenance work packages.

- At Salem, the PMT procedure included a component-based matrix of test requirements.

- At Dresden, PMT requirements, such as valve stroking, current limit switch signatures, and VOTES diagnostic tests were specified for the high pressure coolant injection (HPCI) MOVs, automatic depressurization system (ADS) valves, and Main Feedwater (MFW) components.

- At Maine Yankee, the circuit breaker refurbishment program contained appropriate PMT acceptance criteria for test current and trip time for each trip function (instanteous, short-time, or long-time delay). Also, MOVATS was used to confirm satisfactory installation of a new torque switch on a high pressure safety injection (HPSI) MOV. The closing force was noted to be 44,000 lbs. versus the intended setting of 22,000-24,000 lbs. The valve was disassembled, and no signs of distortion were noted. The overstress was within the bounds of an analysis responding to NRC Bulletin 85-03. The root cause was attributed to failure of a maintenance electrician to follow the procedure, i.e. the switch was installed in a preloaded condition in lieu of having the valve off its back or main seat.

  The NRC also noted that the utility procedures for PMT provide sufficient guidance for adequate testing to be identified. PMT is conducted to ensure compliance with applicable codes and standards, to verify the ability of the component to perform its intended function, and to demonstrate that the repair has been made and that no new problems have been generated.

- At Calvert Cliffs, PMT of 480V breakers, protective relaying of the emergency diesel generator (EDG) logic circuits, and battery systems was performed for each component. Subsystem testing of the 480V breakers and EDG logic circuits was postponed until the system test.

- At Haddam Neck, the NRC inspectors observed PMT of a boration flow path check valve, which had been blocked by boric acid accumulation, and an EDG following troubleshooting of a recurring start failure alarm. Appropriate PMT requirements were specified, equipment was restored to normal configurations, and the PMT was conducted before acceptance for operation.

- At Yankee Rowe, the NRC observed calibration of pressure transmitters in the primary coolant system, voltage relay checks for an emergency diesel generator, checks of differential relays on the main transformer, discharge tests of a 125V DC station battery, and work on nuclear instrumentation. As-found conditions were documented for each item, and each component was tested to pre-determined PMT requirements. PMT requirements are included in the maintenance requests and procedures. The rate of rework was much less than 1%, a very low value. However, although the PMT program was documented adequately and was comprehensive in scope, the NRC felt that improvements could be made in the acceptance criteria, which were often limited and vague.

- At a few plants, i.e. Braidwood, Sequoyah, and South Texas, were properly identified with appropriate scope, acceptance criteria, and implementation. At one plant, a PMT reference manual contained recommended tests for individual components for incorporation into the work packages.

- At Limerick, following a 24-hour endurance test of an emergency diesel generator, subsequent to an overhaul, voltage and frequency could not be properly controlled when the generator was not synchronized to the grid. The problem was insufficient venting of air from the governor.

- At Indian Point 2, minimum PMT requirements were incorporated into work packages automatically, through the Power Plant Maintenance

Information System (PPMIS) for safety-related components. Plant documents were in effect to provide stationwide comprehensive requirements, including details of methods of preparing test procedures to ensure fulfillment of PMT requirements, review of completed test data, test data forms and schedules, and flow diagrams for PMT responsibilities. The NRC determined that the PMT program is well-established and controlled. Three of twenty-five completed work packages reviewed showed failed PMT results. These packages also contained the required rework and/or retest requirements. The final test results were satisfactory and met the acceptance criteria. Approximately 77 generic test procedures were available for use on specific equipment after standard maintenance jobs. These procedures became part of a work package in the preparation stages and were used to address the amount of maintenance performed. The Test and Performance Engineer provides additional test requirements when not covered by the generic procedures.

D.4.2 Deficiencies

- At Fermi, operations personnel accepted an RHR check valve without a stroke test following maintenance. The valve subsequently did not stroke, was incorrectly reassembled and adequate instructions were not provided. This finding had been cited as a violation by the NRC.

- At South Texas, an inappropriate PMT was specified for rebuilding of a seal cartridge for a reactor coolant pump (RCP). The correct PMT could not be performed without a specialized test stand, which the utility did not possess. The NRC convinced the utility to consider acquiring such a stand, based upon the potential consequences of a seal cartridge failure.

- At Palisades, required flow and differential pressure readings were not taken before performing maintenance on one of the Component Cooling Water heat exchangers. This finding was cited as a violation by the NRC.

- At Indian Point 3, an emergency diesel generator failed to start because of low lube oil pressure. The low pressure signals were actually caused by failure to conduct PMT after calibration of the pressure switches.

- At Surry, weaknesses in the PMT program were identified. The PMT program was very limited for equipment other than that covered by ASME Code, Section XI, such as electrical components. However, most I&C and electrical procedures have sufficient testing and calibration requirements that are equivalent to PMT.

- At San Onofre, examples were cited of PMT results not being documented, or of the PMT requirements not being documented in the maintenance work request, or of insufficient acceptance criteria. The test boundaries for system pressure tests did not require marked-up drawings to show the extent of observation required during testing.

- At Zion and Fort Calhoun, similar problems of PMT requirements not being sufficiently specified and the results inadequately documented were noted. At one of the plants, PMT is not always performed, and no explanation was given for not performing it.

  Similar problems were cited at Rancho Seco, in that there were no requirements for engineers to review technical content of PMT procedures or otherwise become involved in PMT. There was no overall program coordination, and PMT requirements were inadequate and routinely did not specify acceptance criteria. Work instructions and procedures were inadequate to properly control PMT following maintenance of the governor of the steam turbine for the AFW turbine-driven pump.

- At H.B. Robinson, there was a lack of guidance for determining PMT requirements, examples of testing that failed to ensure that corrective maintenance was effective, and inadequate system engineer involvement in reviews of completed work requests. Examples also were cited where PMT was not performed on valves in the Safety Injection System (SIS) and the Residual Heat Removal System (RHRS). Out of 30 completed work packages reviewed, only 2 or 3 contained any PMT requirements.

- At Millstone 1, a hydrostatic test of a seal of a Reactor Recirculation pump (RRPS) was performed using a vendor instruction and not a controlled procedure. The retest and acceptance criteria were not definitive enough.

  At the same site, Millstone 2, the NRC cited terminology such as "normal packing leakage" as examples of inadequate acceptance criteria for a charging pump packing repair. At the other PWR unit, Millstone 3, there were no test procedures or acceptance criteria for a repair of a Main Steam Isolation Valve (MSIV) bypass valve.

- At St. Lucie, ASME Code, Section XI pumps are tested for head, flow, vibration, bearing temperature and seal leakage. The NRC considered there to be insufficient emphasis on PMT for non-Section XI equipment, and that the potential for inadequate or deleted PMT was high.

- At Waterford, there were different PMT requirements for MOV actuators. The requirements for MOVs not previously tested using MOVATS equipment were much less comprehensive than those which were MOVATS tested.

  Also, no technical acceptance criteria were identified in the preventive maintenance work package for the minimum capacity of the instrument and station air compressors. In response to NRC Generic Letter 88-14,[24] flow capacity tests of the A and B instrument air compressors were performed in December 1988 and indicate ed capacities of only 50% and 65%, respectively.

- At Clinton, modification of one of the reactor recirculation pumps' seals required PMT for abnormal noise and abnormal leakage when the pump was started. However, the pump was started with no personnel assigned to check for such problems. The NRC considered the operation of major equipment without completion of required PMT to be a significant weakness.

- At Fitzpatrick, existing instrument surveillance and operations surveillance procedures generally were used to verify operability of safety-related equipment. No specific discrepancies were identified with the adequacy of the PMT. PMT requirements were determined by a senior reactor operator (SRO) and checked by a second SRO. The shift supervisor (SS) verified satisfactory completion of tests and restoration of the component to service. The determination of the PMT relied upon the knowledge and personal skills of the SS and SROs. System engineers were minimally involved. The procedure for the system engineer program formally empowers the system engineer to assist in PMT determination, but in practice, PMT was primarily determined by operations personnel. Although the operations personnel for PMT were knowledgeable and experienced, the lack of system engineers' input and the use of generic rather than specific procedures were considered weaknesses. The concern was that PMT operational requirements may not be recognized, particularly during maintenance activities.

- At Cooper, during a repair to restore electrical grounds on the 250VDC bus supply of the shutoff valve in the Emergency Condensate Storage Tank Test Line from the HPCI system pump, it was discovered that the actuator motor insulation was degraded and required replacement. Because there were neither actuator repair procedures nor PMT procedures referred to in the maintenance work request, there was a failure to perform PMT applicable to the scope of work.

There were instances where appropriate PMT had not been performed. In other words, PMT was addressed by procedures, but it was inconsistently implemented. Inadequate or ambiguous specification of PMT resulted from poor control of the work scope, poor instructions, and poor job documentation. Examples of omitted PMT were cited in maintenance on the Service Water System, Drywell Spray, Screen Wash, EDG local control panel, and instrument air drier.

D.5 Failure Trending Analysis

Some detailed examples of the findings concerning failure trending analysis in the MTI reports are the following:

D.5.1 Positive Aspects

- At Vermont Yankee, there was a trending program to identify the need for increased maintenance activities, the need for common mode failure analysis, and also to determine gradual trends in the rates of equipment failure. The program trended 24 components and systems and provided useful information for planning preventive maintenance on the Uninterruptible Power Supply (UPS). Efforts were underway to include root causes, eventually allowing determination of common cause failure. The NRC considered the failure trending program under development to be well conceived and that it would probably contribute to improvements in the predictive maintenance program.

- At Grand Gulf, the utility's management stated that the Station Information Management System (SIMS), once in effect, will resolve the weaknesses in component trending. It will replace two of three computer systems that maintain equipment records and history and will indicate if a component is Q (safety-related), EQ (environmentally qualified), ISI (requires inservice inspection), seismically supported, and/or is an NPRDS component. It will also state applicable procedures, specify the vendor's manual, drawings, component model number and serial number.

  All maintenance work orders for the 35 NPRDS systems, which contain approximately 4,300 components of the over 55,000 plant components, were reviewed by an operational analysis group. Failure trending was performed for the NPRDS components. All maintenance records were screened by the maintenance planners for repeat failures and, when necessary, a Material Non-Conformance Report was issued.

- At Waterford, the knowledge gained from equipment problems and repairs was factored into the preventive maintenance program. All maintenance activities, on both safety-related and BOP equipment, were stored in the SIMS computer database and in the NPRDS. The computer database appeared to be an excellent basis for the strong maintenance trending program.

- At South Texas, the utility effectively identified, resolved, and tracked problems evaluated by engineering. Problem reports and deficiency reports were routinely used for investigation. Trending analyses were used to recognize and mitigate disturbing trends, and for feasibility studies for proposed modifications. Several problem reports and deficiency reports included the causes of the condition and sometimes a detailed root-cause evaluation. The findings were subsequently considered in engineering root-cause evaluations. Corrective actions were always identified, which showed there was effective commitment and followup by management.

D.5.2 Deficiencies

- At ANO Units 1&2 since 1985, the maintenance history was maintained in the computer database and in the NPRDS. The data were only used in job planning. The records were unsuitable for trending because of inadequate technical descriptions of the causes of failure. Maintenance history, including failure analysis and trending capacity, was a weakness in the maintenance program and suggested of poor engineering practices. The NRC inspectors attempted to retrieve historical data on instrumentation known to have a history of failure and setpoint drift, but the data were not in the databases.

  The trending program had not been fully implemented although specific systems were identified by procedure to be monitored. When monies become available, the trending program will be started. No data prior to 1985 were in the data base because of the cost of retrieval and imputing. The lack of description of the component failures in the work orders makes existing data of limited value for trending the number of times a component required corrective maintenance since 1985.

- At La Salle, a trend was defined as three corrective work orders issued on a component in 12 months. The NRC considered this a "gross" approach because potential trends over time or common to a specific model number would not be identified. The frequency was the same for all components, regardless of their importance to safety.

- At Waterford, despite an overall assessment of the trending program as being a strength, the NRC noted that the system engineers had only 1 to 2 years nuclear experience and the majority had only been assigned to the system for 1 year. They were not required to review work orders nor witness PMT or surveillances. Also, they did not receive any formal training and were not aware of the utility's responses to INPO Significant Event Reports and did not have industry experience files for their assigned systems. A majority did not have day-to-day knowledge of their system, nor were they required to. They were unaware of the operating characteristics of the system components and such characteristics of safety-related components were not included in any controlled documents.

- At Clinton, similar problems with the system engineers were noted. The "System Engineer" concept was recently implemented but it was not working well. Some engineers handled several systems, depending upon safety significance and workload. In many cases, they were not aware of the status and functions of the systems. For example, the Control Rod Drive system engineer did not know why only 10 of the 15 CRDs recommended for replacement were replaced. The CRD test timing results were maintained by the station nuclear group but were not transmitted to the system engineer. The Switchgear Heat Removal system engineer was not aware of the planner's request for his involvement in resolving a repetitive hydromotor problem, nor was he aware of several other maintenance work requests (MWRs) open since 1986. The system engineer was not involved in root cause analysis, which limited his knowledge of real problems associated with that system.

  The NRC concluded that the system engineers' involvement was weak in the MWR process, root-cause analysis, field system and component walkdowns, and interactions with planners, maintenance and operations personnel. They did not receive all completed MWRs and were not aware of MWR status, particularly of those open for an extended time.

- At Sequoyah, the engineering program for analysis of equipment failure trend data was in its infancy and little trending was being performed. While historical maintenance records were readily retrievable, no formal trending program had been established at the system engineer level. While some system engineers generated trend data on certain components because of repeated failures, trending was not being consistently performed by all system engineers.

  The NRC concluded that the utility had a relatively strong check valve maintenance program in response to NRC Information Notice 86-01.[25] However, programmatic support and implementation could be strengthened. Regular system walkdowns were not performed or documented, and there was no trending of check- valve failures.

- At Prairie Island, most equipment failures were not documented on nonconformance reports. Balance-of-Plant items were not included so that corrective action, root cause analysis, common-mode failure and program weaknesses could not be trended. However, these items appeared to meet the procedural definition as "QA related" and should have been included in the nonconformance program.

- At Cooper, the utility did not track historic data and identify trends: there was no formalized performance trending program. No specific program outputs were required. The procedure did not specify the content or frequency of reports to management, especially for adverse equipment trends.

  For some systems and plant areas, the equipment data file (EDF) had not been verified, so that not all components were included and subject to maintenance history, and spare parts coverage. Examples were cited for the Screen Wash System, Core Spray System, HPCI, Instrument Air Drier, and MCCs. The NRC considered the lack of component by component checks for the EDF and the Q-List to be a weakness.

D.6 Root Cause Analysis

Examples of significant findings from the MTI reports which concern root cause analysis are the following:

D.6.1 Positive Aspects

- At St. Lucie, a modification to some battery chargers was examined. The current limiting resistor (manufactured by RCL) was modified, with the vendor's approval, to install two adjustable 500 ohm resistors in series. This made the battery chargers more compatible with upgraded control cards by making it easier to adjust output current and voltage. The NRC considered this an excellent example of RCA.

- At Surry, over 4000 deviation reports were in existence in 1989. Root cause analysis was initiated based on the significance of the deviation. A component failure evaluation (CFE) program was set up as a less stringent form of RCA for failures of lesser importance. CFE was automatic for all safety-related failures, except MOVs, which were handled separately. Nonsafety-related failures had CFE only when directed by management.

- At Limerick, failure cause evaluations were sent to the engineering support organization through the Maintenance Request Form (MRF) if necessary to ensure a thorough analysis. For example, during an 18-month inspection and performance test of Class 1E 125V batteries, seam leaks and low cell voltages were identified. The maintenance engineers repaired the leaks and replaced the non-conforming cells. Failure analysis was performed when the Maintenance/I&C trending programs indicated common mode failures.

- At Vermont Yankee, there was no formal training in RCA. However, there was a two-tiered RCA program. At the system-wide level, the operating staff reviewed each failure event for root cause, such as larger human-factors issues including the content and clarity of procedures, training inadequacies, general human-factors, and communications. Engineering reviewed at the component level with a more narrow and technical scope, such as component design, construction and application, maintenance history, testing required, and service life. Assigned engineering personnel recorded failures and probable causes, which were then plotted on trending charts for RCA. There was a backlog of data for which RCA was required.

- At Waterford, in addition to a history file for all components, a root cause evaluation of all failures is conducted. The intent is to extend the operating life of a component or quantify failure information to predict when a component will fail again. Good examples of such evaluations involved the following components:

(1) Failure of the HPSI "B" Pump thrust bearing.
(2) Low flow and premature degradation of the air compressor.
(3) Charging pumps.
(4) Main turbine governor valves.

- At Perry, as a result of failure of some Main Steam Isolation Valves (MSIVs) to close or remain closed, the NRC considered the utility to be performing a thorough, in-depth failure analysis involving the following actions.

  The air-pack actuators from the MSIVs were removed, bench tested and disassembled. Functional testing, visual inspection, and electrical testing of the air packs and air pack components revealed no obvious cause of the failure to close. From discussions with appropriate vendors, the utility concluded that there were two probable failure scenarios:

(1) Failure of one or both of the dual coil Automatic Switch Company (ASCO) solenoids to de-energize or shift from their energized positions.

(2) Failure of the Model 8323 valve to shift position following de-energization of the ASCO solenoids.

  An analysis plan was finalized using a 1987 investigation of similar problems and discussions with vendors. The appropriate parts from the air packs were segregated and sent for lab analysis. The analysis ruled out electrical malfunctions of the solenoids, and there was no foreign material in the valve internals. Body gaskets showed no evidence of exposure to high temperature, nor was there moisture intrusion in the solenoid coils. An annular dimple, indicating some deformation, was observed on the Viton disc of the solenoid operated disc holder. The dimple was caused by the disc holder being pushed against the raised (cone like) exhaust orifice of the solenoid valve body, causing the orifice cut into the seat material. This appeared to cause part of the seat material to be extruded into the exhaust orifice. This dimple suggested that the disc holder could be held in an energized position, even though the solenoid had been de-energized, and would prevent the control air from being exhausted to the atmosphere, and therefore, prevent the MSIV from closing. Laboratory results and final root cause had not been determined at the conclusion of the NRC inspection. Utility engineering and EQ personnel were pursuing potential design modifications to the air packs, based on discussions with other utilities and with the vendors of the air pack components.

- At Calvert Cliffs, management attention was now given to root cause analysis, due to better reporting of work accomplished and better retrieval of component history. Meaningful failure analyses could be performed because data were available. Two RCA reports of components with high failure rates were reviewed and found to be satisfactory, with a detailed analysis and recommended actions. However, no plans to implement these recommended actions had been developed although they were formulated approximately 4-6 months earlier.

  Approximately 95% of Electrical and I&C personnel have completed the latest course in RCA and had a good understanding of their task effort. Where RCA was performed with maintenance personnel participating, the work was well documented and proper corrective action had been taken.

- At Prairie Island, the System Engineer concept had been implemented for several years and was a significant strength. System engineers perform failure analysis, root cause analysis, and identify adverse trends to monitor system performance.

- At South Texas, an evaluation of a manual trip of one of the units caused by a loss of Main Feedwater was complete and comprehensive. It contained a time line associated with the MFW pump turbines, an energy/barrier/target analysis, and an events and causal factors sheet. The root causes were identified, and comprehensive actions were specified for the panel power supplies, electrical overspeed trip scheme, system (hydraulic) damage, and the problem of excessive system cooldown.

D.6.2 Deficiencies

- At Palo Verde, an emergency diesel generator (EDG) was run with a known oil leak in a cylinder head for 18 hours (out of a 24-hour test) when it had to be shut down. No engineering analysis had been done to determine whether the diesel could run with the leak. The utility had identified numerous elbow fitting and drain plug failures in the EDG jacket water system which are subject to corrosion. After replacing several of the parts, more of the same parts failed. The utility was unable to show that new parts had been ordered or installed for the emergency diesel generators on the other two units at the plant site. The utility's failure to take effective corrective action to preclude repetition of the significant failures was cited by the NRC as an apparent violation of 10CFR50 Appendix B.

- At Duane Arnold, the utility failed to take prompt corrective action or perform a root cause analysis for problems with the thermal overload on the EDG jacket cooling pump motors and associated contacts which protect the motors from excessive fault currents. There were no sizing criteria for the thermal overloads, and the design documents were not updated for changes in the heater's size. The failure to take prompt corrective action and perform a root-cause analysis in a timely manner was cited by the NRC as a violation of 10CFR50 Appendix B.

- At the same plant, loose terminations or connections caused loss of safety-related equipment. The NRC inspectors determined that a subtle trend existed, which was not analyzed by the utility. No root cause analysis was performed to determine if aging is the cause and no corrective actions were taken such as infrared scanning or physical verification of tight connections during routine preventive maintenance.

- Also at that plant, the Corrective Maintenance reports did not contain any descriptions of "As Found." "Probable Cause" blocks were left unfilled or the cause given appeared to be unrelated to the problem in the work packages reviewed by the inspectors. This omission could adversely affect trend capabilities, rework identification, and root-cause analysis.

- At the same plant, a self-initiated Safety System Functional Inspection (SSFI) identified that repeated corrective maintenance was required for the high-pressure coolant injection (HPCI) system because of inadequate application of root-cause analysis.

  Despite an established goal of zero unplanned reactor trips, root cause analyses were not required, only suggested, when an unplanned trip is initiated by balance of plant (BOP) systems or components.

- At Hope Creek, the Managed Maintenance Information System (MMIS) was used by system engineers to review failure events at the component level. Completed summaries of corrective maintenance work summaries were analyzed to determine if any action was required and inputs to the station performance trending/monitoring program. However, in reviewing fifteen completed work orders, not one had a "cause of failure" or "cause code" entered. This was cited by the NRC as a violation of Tech Specs which require that written procedures be established and implemented for various plant activities.

- At Salem, the system engineers identify root causes and corrective actions, but the analyses were not sufficiently deep and the threshold for instituting root cause analysis was too high. There were no procedures, and training in root cause analysis for engineers was scheduled but not implemented.

- At San Onofre, the root-cause determination was very superficial, citing symptoms, not causes, and there was excessive use of the term "other". In 132 non-conformance reports (NCRs) for Safety Injection (SI) and Main Feedwater (MFW), 67% had "other" as a cause, or cited "normal wear" or "design inadequate". "Personnel error" was often cited, with no explanation. The corrective actions were aimed at the symptoms.

- At Zion, the system engineers were not involved in root cause analysis. There was failure to fully document "As Found" conditions. Simple, general statements such as "Completed Calibration" or "Repaired" were used to describe completed work. Cause codes were not indicated in 8 out of 27 work requests.

  Overall, the trending and RCA programs for maintenance were inconsistent and fragmented. A Deviation Report (DVR) was only recently implemented. Other trending reports included Instrument Discrepancy Reports (IDR), Certified Instrument Discrepancy Reports (CIDR), Total Job Management (TJM), and NPRDS. There was a high threshold for initiation of Deviation Reports, and inconsistent application of thresholds. Also, there was a very narrow range of events. There were different but insufficient cause codes for documenting the same maintenance problems in TJM, NPRDS, and the Problem Analysis Data System (PADS). There was insufficient or overlapping coverage for some components.

- At Hatch, on the positive side, the training course for RCA included MORT, event and causal factors, fault tree, change, barrier and Kepner Tregoe problem analyses.[26,27] Also, the work history reports for the Unit 1 4160VAC System and the High Pressure Coolant Injection System, which gave details of maintenance work orders for at least the last two years, showed that repetitive failures of the two systems had not been a problem and that RCA for these two systems had been satisfactorily carried out.

  However, there was inadequate detail in the procedure on how to perform a root-cause analysis, and, for a HPCI MOV failure, no RCA was performed, and too much time was taken to determine the correct cause of leakage from a seal in the Main Feedwater pump. In addition, no RCA was conducted following the failure of the motor for the RCIC steam supply isolation MOV.

- At Fort Calhoun, the NRC inspectors stated that there was no effective root cause analysis process nor means to identify maintenance that is rework of previous maintenance. For the component selected, a HPSI flow transmitter, there was no preventive or predictive maintenance history, so that the information was ineffective for trending and root cause analysis. The Computerized History and Maintenance Planning System (CHAMPS) database of equipment history was poor and lacking in the detail required for a good trending and RCA program.

  Leakage of the main Feedwater pump leakage was a continual problem, yet no RCA was performed. There was a high maintenance frequency for MFW flow control valves, with an average of 15 repairs per year from 1984 to 1988. Improved preventive maintenance and an RCA program for MFW pumps and valves was considered necessary by the NRC. Also, the maintenance history files for MFW were very poor, with few records of corrective maintenance and none of predictive or preventive maintenance. The files were ineffective for trending or RCA.

- At Dresden, RCA was not performed for a subtle trend of failures of a 4160 VAC breaker to open and close. Also, the analysis of failure for a Low Pressure Coolant Injection (LPCI) 4160 VAC breaker was inadequate because maintenance at the required frequency was not performed and this was not identified. Similarly, there was inadequate evaluation of the failure of an Isolation Condenser Makeup MOV to open. Of 25 work requests reviewed on 4160 VAC breaker problems, none contained a description of the "As Found" condition or "Maintenance Cause". This was considered to hinder identification of rework and root-cause analysis.

- At ANO, root cause analysis was weak, because failure of the component was inadequately described in the "Work Performed" block of the work request. Thus, trending of equipment failure could not be successfully implemented. Maintenance records were not used by any maintenance group nor were they used in root cause analysis. However, a new preventive maintenance program was being developed that may establish historical trending records that could be easily accessed.

- At Grand Gulf, similar problems with problem descriptions were identified. In particular, the NRC characterized the description of problem and corrective action for several maintenance work orders as being too cryptic and therefore, not much good for historical trending.

- At Clinton, the NRC inspectors noted that in completed maintenance work requests, the cause of failure was listed as "Plant Aging" whenever no root-cause could be easily determined, specifically 312 times in the previous two years. The following hardware failures were associated with these causes of "Plant Aging" failure:

  (1) Blown fuses.
  (2) Leaks (air, water, steam, oil).
  (3) Valve failures (open/close).
  (4) Valve leaks (packing, flanges, bonnets, Appendix J Containment Leak Rate Testing).
  (5) Drive belt failures (worn, frayed, fell off).
  (6) Pump failures (noise, below capacity, no flow).
  (7) Components (broken, damaged, clogged, missing, eroded).

  According to the MTI report, none of the "Plant Aging" failures seemed to be age-related. There was no formal method to assess the corrective action for those types of failure to determine whether identical components could have been subjected to common mode "plant aging" failure. The NRC therefore concluded that trending, rework identification, and root cause analysis could be hindered.

- At the same plant, 11 hydromotor actuators, used in safety-related HVAC systems had tags attached, some of which dated to 1986, showing that most had failed during operation and needed to be rebuilt and/or overhauled. Even though a root cause analysis was not been performed to determine which components had failed, parts from the failed hydromotors were used to repair others. The utility stated that all repaired units are tested before installation. Numerous maintenance work requests had been issued because of problems with hydromotor actuators. The most significant failures appeared to be excessive cycling, shaft misalignment, miscalibration of the pressure- differential switch, and leaking hydraulic oil. The hydromotor for a Division 1 switchgear HVAC unit had been running continuously for 2 years according to the NRC resident inspector. Although two maintenance work requests were issued in 1986 and 1987 to address the same problems, they had been closed because the utility decided that the hydromotors were designed to run continuously. However, the NRC inspectors concluded that the motors should not run continuously and that the root cause had not been identified.

- At Fitzpatrick, there were procedures to identify the need for a root cause analysis, especially when significant adverse quality conditions were identified. From discussions with system engineers, root cause analyses were appropriately conducted to prevent recurrence, and corrective actions are followed to ensure correctness of analysis results. An example of properly conducted root cause analysis was the ongoing evaluation, including laboratory tests, to resolve problems with the Instrument Air System. However, for preventive maintenance, root cause analyses appeared to be minimal and limited to cataloguing of component failure modes in the computerized databases. Also, failure analysis and root-cause evaluation were recent programs and were not fully implemented.

As in other plants cited above, problems in documentation were noted where "Action Accomplished" and "Cause" sections of the work tracking form were not always fully used. In one case, areas in the work package procedure that asked for specific information were left blank, such as when an adverse condition was found during an inspection of a check valve, the spaces for comment and apparent cause were left blank.

Documentation problems were noted at several other plants:

- At Ginna, descriptive information of the work completed was, at times, incomplete, or sketchy. The NRC requested a review of 100 completed work orders. The utility found that in eight of them, the "As Found" condition was either blank or there was insufficient information.

- At Haddam Neck, the NRC considered the maintenance documentation to be inadequate, thereby negatively impacting trending and root cause analysis. Use of "Failure Code" and "Actual Work Performed" was not explained in the procedure.

- At H.B. Robinson, some work packages contained work instructions, rather than a description of the "As Found" conditions, thus limiting the usefulness of the data. Some work packages contained "As Found" descriptions in the "Cause of Trouble" field.

- At McGuire, most discrepancies in the work requests related to identification of the cause of the problem, including the lack of cause codes. There was inattention to detail in completely and correctly entering information. The utility personnel did not consider the lack of cause codes to be a problem because descriptive entries on failures were included which had been extensively reviewed by systems expert personnel before sign-off of the work requests. Also, RCA was triggered by other means, such as failed surveillance tests. The RCA packages reviewed by the NRC were thorough and complete with metallurgical analyses where necessary. However, the utility agreed to better define the initiators of RCA.

- Also at McGuire, the utility identified 102 deficiencies for the control-room instrumentation. Twenty-four were for safety-related equipment, and 78 were for non safety-related equipment. Many were for instruments located inside containment which are, therefore, not available for maintenance until an outage. The NRC considered that only the deficiencies were identified, and not the root-causes, and that more emphasis is needed on RCA.

- At North Anna, the root-cause evaluation program and its implementation were adequate, but a consistent methodology was not in place, and the quality of the evaluations reviewed by the NRC was poor. The NRC noted that none used industry-accepted techniques for identifying the ultimate root causes for failures. The evaluations ranged from one to two paragraphs of deductive logic discussion, to more extensive evaluations approaching the guidelines of the station procedure governing "Root Cause Evaluation."

- At Cooper, the NRC identified four examples in which degradation of equipment and/or improper maintenance and modification activities failed to result in a root cause analysis because there was no clear "trigger" mechanism beyond that identified in current plant procedures. The utility relied on reviews by systems engineers and supervisors of work activities and documents to identify conditions requiring escalation to management and/or additional evaluation and/or corrective or preventive actions.

Examples were cited where:

(1) Conditions adverse to quality were encountered but were not cited as requiring further evaluation and corrective or preventive actions, and

(2) Significant conditions adverse to quality were identified, but a nonconformance report was not issued.

Specific examples involved a manual RHR valve which, after maintenance, leaked severely when pressurized because of the failure to pack or incompletely pack the valve; a leaking service water solenoid pilot valve; an Emergency Diesel Generator intercooler failure; and a burned-out motor for an RHR pump suction line motor-operated valve. Root cause analysis was **not** performed in any of these cases.

- At Fermi, system engineers had not received specified training, were not fully aware of system status, did not review work requests, and were not involved in trending and root cause analysis. Communications between systems engineers and maintenance was poor. One engineer was responsible for nine systems, and served as a backup for nine more.

- At River Bend, there were 33 unplanned automatic reactor scrams during the first 47 months of critical operation. Approximately half occurred during plant startup. Of the 336 root-causes of these scrams, 286 were eliminated. In three, or possibly four, of all of the scrams maintenance activity was identified as one of the root causes.

  However, root cause determination of the engineered safety features actuation system (ESFAS) actuations was not being performed. There were 66 actuations in approximately two and one-half years. The data base contained only a brief description of each. ESFAS actuations did not receive the same level of rigorous examination as reactor scrams. The limited data indicated that possibly in seven of these actuations the root cause was related to maintenance.

- At the same plant, an unexpected reactor scram occurred because the contacts on a three-position key-operated test switch were open, rather than normally closed, during a reactor protection system (RPS) monthly closure test of a MSIV. The key can only be removed when the switch is in the normal position. Although the key was removed, the switch was actually about 1/32" off the normal position and the contacts were open. Eight of 23 spare switches failed. The utility's engineering staff verified that the switch contacts for all 24 installed switches were in the proper position. Restart was authorized, in part, on the basis of GE design philosophy that includes a light or annunciator when switches are used for bypass. The NRC was concerned that this decision was not based on a rigorous evaluation.

D.7 References

(1) U.S. NRC, "Potential Loss of Motor Control Center and/or Switchboard Function Due to Faulty Tie Bolts," Information Notice 88-11, April 7, 1988.

(2) U.S. NRC, "Erosion/Corrosion Induced Pipe Wall Thinning," Generic Letter 89-08, May 2, 1989.

(3) Gunther W., Lewis R., Subudhi M., "Detecting and Mitigating Battery Charger and Inverter Aging," NUREG/CR-5051, BNL-NUREG-52108, pp. 5-4, 5-5, 5-7, August 1988.

(4) U.S. NRC, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," IE Bulletin 85-03, November 15, 1985.

(5) U.S. NRC, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," Bulletin 85-03, Supplement 1, April 27, 1988.

(6) U.S. NRC, "Modified Enforcement Policy Relating to 10 CFR 50.49 Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," Generic Letter 88-07, April 7, 1988.

(7) U.S. NRC, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," Generic Letter 88-14, August 8, 1988.

(8) Instrument Society of America, "Quality Standard for Instrument Air," ISA S7.3-75, Reapproved 1981.

(9) U.S. NRC, "Quality Assurance Program Requirements (Operation)," Regulatory Guide 1.33, Revision 2, February 1978.

(10) American Society of Mechanical Engineers, ASME Boiler and Pressure Vessel Code, Section XI, Subsections IWP and IWV, code in effect.

(11) U.S. NRC, "Circuit Breaker Failures Due to Loose Charging Spring Motor Mounting Bolts," Information Notice 88-42, June 23, 1988.

(12) Institute of Electrical and Electronics Engineers, "Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations," IEEE Standard 450-87, code in effect.

(13) Institute of Electrical and Electronics Engineers, "Recommended Practice for Design of Reliable Industrial and Commercial Power Systems," IEEE Standard 493-1980.

(14) U.S. NRC, "Failure of Westinghouse W-2 Type Circuit Breaker Cell Switches," Information Notice 87-61, December 7, 1987.

(15) U.S. NRC, "Failure of Westinghouse W-2 Type Circuit Breaker Cell Switches," Information Notice 87-61, Supplement 1, May 31, 1988.

(16) U.S. NRC, "Effect of Circuit Breaker Capacitance on Availability of Emergency Power," Information Notice 88-50, July 18, 1988.

(17) U.S. NRC, "Failures of Small-Diameter Tubing in Control Air, Fuel Oil, and Lube oil Systems which Render Emergency Diesel Generators Inoperable," Information Notice 89-07, January 25, 1989.

(18) U.S. NRC, "Biofouling Agent: Zebra Mussel," Information Notice 89-76, November 21, 1989.

(19) U.S. NRC, "Maintenance Deficiency Associated with Soleniod-Operated Valves," Information Notice 90-11, February 28, 1990.

(20) U.S. NRC, "Sheared Pinion Gear-to-Shaft Keys in Limitorque Motor Actuators," Information Notice 90-37, May 24, 1990.

(21) U.S. NRC, "Retention of Broken Charpy Specimens," Information Notice 90-52, August 14, 1990.

(22) U.S. NRC, "Failure of Air-Operated Valves Affecting Safety-Related Systems," Information Notice 88-24, May 13, 1988.

(23) Institute of Electrical and Electronics Engineers, "IEEE Maintenance Good Practices for Nuclear Power Plant Electrical Equipment," 89TH0248-5-PWR, copyright 1988.

(24) U.S. NRC, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," Generic Letter 88-14, August 8, 1988.

(25) U.S. NRC, "Failure of Main Feedwater Check Valves Causes Loss of Feedwater System Integrity and Water Hammer Damage," Information Notice 86-01, January 6, 1986.

(26) Johnson W., "MORT: The Management Oversight and Risk Tree," Journal of Safety Research, Vol. 7, No. 1, pp. 4-15, March 1975.

(27) Ferry T., "Modern Accident Investigation and Analysis," John Wiley & Sons, Second Edition, pp. 141-182, copyright 1988.

APPENDIX E

SPECIFIC EXAMPLES OF INSIGHTS FOR SYSTEMS AND COMPONENTS FROM MTI REPORTS

E.1 Systems

E.1.1 Auxiliary Feedwater Systems

E.1.1.1 *Specific Aging Related Insights*

- At Fort Calhoun, the check valves for the AFW discharge had a consistent history of external leakage. An examination showed loose disc stops and missing stop welds.

- At St. Lucie, following a manual reactor trip at Unit 2, both MOVs for the motor-driven AFW pumps went fully open as intended. One valve was later closed by the operators, and the other was throttled to 200 GPM flow rate. The operators later tried to reposition the latter valve, but it would not move. Also, the fully closed valve appeared as fully open on the control board. The throttled valve would not respond because the stem and nut were galled and seized together; thus, it could not be manually positioned. The fully closed valve could not be remotely positioned open because the drive pinion gear limit switch had worn to the point that it was not meshed with the drive sleeve bevel gear. The limit switch was left indicating a "full open" signal to the control room and would only allow the Limitorque motor to rotate in the closing direction.

- At H.B. Robinson, repairs were required on the motor-driven AFWS pumps because of a lack of periodic maintenance inspections.

E.1.1.2 *Inclusion in a Reliability Centered Maintenance Program*

Positive Aspects

- At D.C. Cook, an RCM program had begun with AFW as one of the pilot systems.

- At Calvert Cliffs, several safety system analyses using RCM methodology had been completed, but results were not scheduled for implementation until the end of 1990. The systems included the AFWS.

Negative Aspects

- At Rancho Seco, a failure modes and effects analysis (FMEA) had been prepared for the overspeed event for the AFWS turbine on January 31, 1989, but it only addressed the consequences of overpressurization of the AFW turbine governor. The consequences of a loss of nitrogen supply or mistaken valve operation had not been addressed.

E.1.1.3 *Preventive Maintenance Practices*

Positive Aspects

- At Maine Yankee, the utility had replaced a check valve in the Emergency Feedwater system instead of just repairing a leak in the valve body. Provisions for PMT had also been included in the work request.

Negative Aspects

- At St. Lucie, the utility did not have repair procedures for the motor-driven and turbine-driven AFW pumps and Limitorque MOV actuators. In such cases, repairs had to be made using vendor technical manuals. PM procedures, however, were in effect for those components.

- At Indian Point 2, a recent failure of a coupling for an AFW pump showed a weakness in the definition of the lubrication requirements for plant equipment.

- At Rancho Seco, proper preventive maintenance had not been established for the governor and turbine overspeed device and the governor oil-dump solenoid feature of the AFW turbine.

- At North Anna, as an example of procedures for electrical and mechanical PM or disassemble/inspect repair which permitted or encouraged the addition of repair steps, the NRC cited a maintenance procedure for turbine-driven AFWS pumps, which appeared to permit ASME Code Section XI repair steps involving welding, grinding, or machining the pump casing to be written in without normal review or approval.

Also, a general procedure for lubricating various system pumps, including the AFWS pumps, stated that the samples may be taken with the pump running or within 15 minutes after shutdown. However, the PM procedure implemented this procedure by stating that "samples must be taken right after the pump is shut down," rather than specifying the quantitative time limit.

E.1.1.4 *Incorporation of Vendor Recommendations*

- At D.C. Cook, the NRC cited a violation in that the vendor manual for the AFW pump required that the pump packing be adjusted (for a controlled amount of leakage), while the pump is operating. This procedure had not been incorporated into the maintenance procedures for the AFW system. The NRC felt that although no problems had been noted, rotor seizure, scored shaft sleeves, or burned packing could have resulted.

- At Rancho Seco, the governor on the AFWS turbine had been replaced several times during the past year because of water intrusion problems. During the most recent replacement, the vendor had made undocumented changes to the device, which made the direction of rotation critical. Subsequently, poor communications resulted in the wrong direction of rotation being specified, which contributed to the overspeed incident on January 31, 1989. On that day, the AFWS pump governor and its mechanical overspeed trip both failed during a post maintenance test, resulting in **both trains of AFWS being pressurized beyond design stress values,** and therefore making the system inoperable because of questionable piping integrity.

  This finding was cited by the NRC as a violation.

- At North Anna, the NRC determined that most vendor information requiring utility action did not necessarily pass through Licensing, so that there was a high probability that such information may not be received by the responsible department and acted upon. One example concerned the AFWS pumps, where the manual pertained to ball bearings, not the sleeve bearing which the pumps actually had.

E.1.1.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Indian Point 3, the AFW pumps were subjected to vibration analysis and pump differential pressure measurements.

- At Surry, check valves are installed in each of the three steam inlet lines of the common header to the AFW pump turbine. At least one valve per unit per outage was disassembled for inspection. Leak testing was also performed on Instrument Air check valves supplying air to solenoid-operated valves (SOVs), which open the turbine steam admission valves.

- At Fort Calhoun, PM was performed on motors for the Auxiliary Feedwater pumps, as well as the Condenser Vacuum pumps, and other safety-related pumps. The procedure specified oil sampling, strobe light, and a vibration instrument for recording motor and pump operability data.

Negative Aspects

- At Shearon Harris, there was no vibration monitoring of AFW pump motors.

- At Surry, despite previous replacement of governors and tappet balls, steam-driven AFW pump had not been tested for the overspeed trip function. This finding was cited by the NRC as a violation.

- At Zion, the utility had failed to take adequate or timely corrective action for **17 years** to maintain or test the overspeed mechanism for the pump turbine of the Unit 2 AFW system. The Unit 1 mechanism had been tested once, approximately 17 years after pump installation, during April 1987 with limited success. The manufacturer had recommended testing once per week, and also that the moving parts of the trip and throttle valve should be lubricated once per week and that all moving parts be kept clean. The NRC cited this finding as a violation.

- At Rancho Seco, the work request for removal and detailed diagnostic inspection of the valve linkage for the AFW pump turbine governor did not contain acceptance criteria for critical measurements, neither min./max. expected values, nor maximum measurement tolerances. The NRC cited this finding as a violation.

  Also, proper periodic testing and corrective action had not been established for the pump governor and turbine overspeed device of the AFW and the oil-dump solenoid feature of the governor.

- At Fort Calhoun, the surveillance test procedure for AFW pumps did not include all of the requirements of ASME Section XI, paragraph IWP-3100,[1] so the tests were not repeatable and were not accurate to determine pump operability.

- At H.B. Robinson, an informal vibration analysis program, using a sophisticated technique, which evaluates both the velocity and displacement of vibration, was in place for approximately 100 safety and non-safety related components which are in full-time operation, such as Service Water pumps. However, standby safety related pumps such as Safety Injection, Auxiliary Feedwater, and Containment Spray were monitored under a less sophisticated and sensitive program specified under the ASME Code, Section XI.

- At Prairie Island, failure of a turbine-driven AFW pump surveillance because of a defective governor was not documented as a nonconforming item, nor were trending, root cause analysis, or corrective actions taken.

- At Braidwood, the NRC was concerned with the adequacy of the periodic testing of the AFWS pump diesel engine. The technical specifications required that the AFWS pump achieve a flow greater than 85 GPM and meet vendor recommendations. They also required that the diesel engine of the AFWS pump be inspected as per the manufacturer's recommendations for the "class of service" at least once every 18 months during shutdown. The NRC concern was that the periodic checking of the valve and fuel injector adjustments in the operating mechanism, recommended by the vendor manual, had never been performed during preoperational testing and refueling. This failure to check the adjustments had all been allowed without an engineering evaluation. Also, the capability to achieve rated speed in 10 seconds was not confirmed.

  A minor deficiency was noted in the in-service testing (IST) procedure for the AFWS pump. The ASME Code Section XI requires that the IST be conducted with the pump operating at the required reference speed, and that the system resistance be varied until either the measured flow rate or differential pressure equals the corresponding reference value. The flow rate was checked during the surveillance but not verified to agree with its reference value until other IST quantities had been measured. This variation in the testing sequence resulted in an adequate test, but was not in accordance with the ASME code.

E.1.1.6 *Failure Trending*

<u>Positive Aspects</u>

- At Rancho Seco, the maintenance history of equipment contained in the plant computerized information system (NUCLEIS) was incomplete. For example, the history of the previous failures of the turbine governor and mechanical overspeed trip of the AFW pump was inadequate. Industry and plant experience, i.e. trend data and PRA data, was not used effectively, such as in the case for previous AFW pump turbine failures. Historical records were available, but they were not easily retrievable.

<u>Negative Aspects</u>

- At Haddam Neck, engineers had both system and project assignments. For example, problems associated with the emergency diesel generator, condensate system and auxiliary feedwater system were all handled by the same engineer, which led to a delay in resolving problems with an emergency diesel generator.

E.1.1.7 *Configuration Management*

- At North Anna, a configuration management and project to update design-basis documents had been started in 1988 to establish plant physical configuration and obtain component design information for major components. The AFWS was a priority for the first two years, along with other safety-related systems.

E.1.2 Feedwater Systems

E.1.2.1 *Specific Aging Insights*

- At Surry, there were numerous examples of end-use devices which vibrated during normal operation that were connected to stationary Instrument Air root valves by lengths of small-diameter copper tubing, despite extensive industry experience with trips and transients because of vibration-induced air line failures. (North Anna tripped in February 1989 because of vibration-induced failure of an IA line on a MFW regulating (control) valve, coupled with a plug failure and tube rupture of a steam generator tube.

- At Hatch, abnormal seal leaks had been noted on each of the four Feedwater pumps. A consultant from the pump manufacturer, Byron-Jackson, noted that normal seal water flow was routed back to the Condenser Hotwell, causing flashing and restricted flow. Proper routing should have been to the intake of the condensate booster pump suction, or else the size of the piping should have been increased.

  Also, a condensate pump experienced high vibration and shaft misalignment, with worn bearing and wear rings. The root cause had been attributed to improper alignment between the pump and motor. Cracks had been discovered in the section of pump casing (52" diam. x 104" long) containing the suction and discharge flanges.

- At Fort Calhoun, MFW pump leakage was a continual problem, and no root cause analysis had been performed. There was a high maintenance frequency for MFW flow control valves, with an average of 15 repairs per year from 1984 to 1988. The NRC considered that improved programs of preventive maintenance and root cause analysis for MFW pumps was warranted.

- At Braidwood, several leaks were noted on two MFW pumps at one unit. The leaks were scheduled for repair during a plant derating.

- At River Bend, there were oil leaks on all three MFW pumps, as well as the electro-hydraulic control pump skid, the generator hydrogen seal oil skid, and the emergency and high pressure core spray (HPCS) diesel generator engines.

E.1.2.2 *Prioritization of Balance of Plant Systems*

<u>Positive Aspects</u>

- At Indian Point 3, an important-to-safety category had been defined for addition to the PM program. Systems and components such as Condensate, Heater Drain, Feedwater pumps, Condensate Polisher, MSIVs, and Feedwater Control Valves had already been included.

<u>Negative Aspects</u>

- At Zion, there was inadequate attention to non safety related activities and balance-of-plant equipment.

E.1.2.3 *Inclusion in a Reliability Centered Maintenance Program*

- At Zion, there was a management commitment to a RCM type study of the Feedwater System.

- At LaSalle, limited principles of RCM had been applied. Only an RCM study of the Feedwater System had been performed, but others were planned.

- At Braidwood, the utility's philosophy included some aspects of the principles of RCM. The main feedwater was being reviewed for full implementation of RCM. Maintenance history and vendor recommendations were used as sources.

E.1.2.4 *Preventive Maintenance Practices*

Positive Aspects

- At H.B. Robinson, a MFW control valve was repaired to correct a flange leak by taking the plant off-line, rather than performing a temporary repair.

Negative Aspects

- At Salem, the PM for the actuators of the MFW control valves resulted in the air-operated actuators having several diaphragm bolts which did not meet minimum thread engagement requirements.

- At Calvert Cliffs, during maintenance of a control valve for a MFW heater, a new piston O-ring had been supplied for the valve actuator, instead of the old style piston cup seal ring. Engineering had not been properly notified about the change, but a Drawing Change Request was subsequently issued.

  Also, air tubing for the control valve of the MFW heater had been disconnected at the valve operator and left unplugged by I&C personnel. Protection of open piping under 2 in. diameter was not specified, contrary to good industry practice.

E.1.2.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Surry, the utility had a well-defined program for inspecting pipe for erosion/corrosion thinning, in response to failure of a heater drain pipe and Generic Letter 89-08.[2] The pipe section that failed (at discharge from flow control valve LCV-122B) had not been in the program in effect before January 1, 1990; however, the adjacent elbow was part of the program. The utility was compiling a list of all throttling valve configurations covered in the program.

- At San Onofre, the Rotating Equipment Vibration Monitoring Program included monitoring and trending of main station turbines, MFW pump turbines, Circulating Water and Condensate pumps, and Stator Water pumps. The utility had just received a state-of-the-art "Schenck" 550,000 lb. rotor balancing machine of hard bearing and slow speed design. Other programs included condition monitoring of the lube oil.

- At Fort Calhoun, the CHAMPS preventive maintenance history of the trending system of the MFW Pump A Motor and Pump A vibration analysis were reviewed by the NRC. The latter included a spectral plot, identification of several peaks above threshold, and overall trending values. The NRC concluded that the trending program had the potential to become a useful tool. The nature of the outstanding work items showed utility recognition of required actions, and corrective measures had been initiated.

- At Haddam Neck, the utility decided to inspect major MFW check valves in response to NRC Information Notice 86-01.[3] Other major system check valves had been added.

- At Yankee Rowe, in response to NRC Generic Letter 89-08, for erosion/corrosion induced by pipe wall thinning, the utility was trending data from approximately 60 components which had been selected for examination. The lines included extraction steam, heater drains, condensate, feedwater, auxiliary steam, and steam generator blowdown.

- At Sequoyah, the MFW pumps were subjected to oil sampling. Acoustic monitoring was used to detect valve leakage and loose parts. Formal procedures were not in effect, and so it depended heavily on the expertise of the personnel performing or supervising the examination. Activities included monitoring MFW long cycle valves for leakage during normal plant operation, MFW regulating and bypass valves for leakage during plant startup, and other valves upon request.

- At River Bend, degraded rotating equipment such as a circulating water pump motor and an alignment problem with the speed increaser of the MFW pump had been identified under the vibration monitoring program. This program included spectral data, wave forms, and trends for each point monitored. Reports of adverse trends were distributed to system engineers, maintenance and operations personnel.

E.1.2.6 *Post Maintenance Testing*

Positive Aspects

- At Dresden, for certain MFW components, PMT requirements such as valve stroking, current limit switch signatures, and VOTES diagnostic tests had been appropriately specified.

E.1.2.7 *Root Cause Analysis*

Positive Aspects

- At Hatch, various problems with the Feedwater Control System had been solved for capacitors, density correction instrumentation, cascade switches, recorders, and feedwater controllers.

- At Dresden, several deviation reports, LERs, PADs and work packages were reviewed for the failure of Feedwater Regulator Valve 2A due to blockage from debris. The RCA did not appear to correct the problem. However, the NRC determined that a new valve had recently been installed in Unit 2 to prevent debris intrusion. The "stacked disc" design was similar to the Unit 3 Feedwater Regulator Valve, for which there had been no blockage problems.

- At Haddam Neck, Corporate Engineering's recognition of the potential for loose parts with respect to the failure of a MFW regulating valve was very timely.

Negative Aspects

- At San Onofre, the root cause determination was very superficial, citing symptoms, not causes, and there was excessive use of the term "other". Sixty-seven percent of a total of 132 non-conformance reports (NCRs) for Safety Injection and Feedwater had "other" as a cause, or cited "normal wear" or "design inadequate". "Personnel error" was often cited as a cause with no other explanation. The corrective actions were aimed at the symptoms.

- At Hatch, excessive time was taken to determine the cause of a seal leak on Main Feedwater.

E.1.2.8 *Documentation of Maintenance Records*

Positive Aspects

- At Perry, the NRC reviewed 14 mechanical maintenance work orders, most of which related to MFW. The instructions on the work orders were usually very detailed. The summaries of the work performed were detailed so that the root cause could be determined and provided good descriptions of the corrective actions taken. PMT, if required, was included in the work orders. The quality of mechanical work orders was very good. Generally speaking, quality of the work orders was also very good for 12 I&C maintenance orders, a few of which related to MFW.

Negative Aspects

- At Fort Calhoun, all applicable equipment in the MFW system was included in I&C maintenance. However, the maintenance history files for MFW were very poor, with little corrective maintenance, and no preventive or predictive maintenance records. The files were ineffective for trending or root cause analysis. The PMT requirements were too brief and undefined.

- At LaSalle, the work orders for maintenance on relief valves in the Feedwater and other systems identified "set point drift" as a failure cause. The cause was not specific enough to verify corrections.

E.1.2.9 *Incorporation of Vendor Recommendations*

- At Fort Calhoun, the MFW Regulating System calibration procedure directed the use of vendor manuals, but those available were inadequate, or not available at all.

E.1.3 High Pressure Injection Systems

E.1.3.1 *Specific Aging Insights*

Negative Aspects

- At Surry, SI MOV body to bonnet fastener washers were corroded, and wrapped in poly or bagged to control small leaks or prevent the spread of contamination.

- At Surry, the support base and fasteners of certain containment spray pipes were excessively rusty. The SI MOVs had very thick deposit of unknown substance on packing leak off drain piping. An SI pump had upper seal leak with heavy boron buildup and excessive grease at lower motor bearing.

- As explained in detail in Appendix D, Section D.1, at Limerick, corrosion of the system piping of the Essential Service Water system to the compartment unit coolers of the HPCI pump resulted in a valve being filled with a soft, black sludge, and an irregular scale buildup on the internal pipe wall.

- At Dresden, oil leaks on the inboard seal and oil return lines of the HPCI main pump resulted in a sizeable puddle of oil on the skid.

- At Sequoyah, degradation of the stems and packing glands resulted in boron buildup on twenty SI valves.

- At Palisades, a large buildup of boric acid was noted on SI MOVs inside containment.

- At Palo Verde, three SI charging pumps were operated with oil leakage rates exceeding leak limits.

- At North Anna, oil misting caused heavy oil puddles on the floor from packing that was leaking from two CVCS valves.

- At Millstone 2, the repair frequency for charging pump packing showed an increasing trend (less than one month since previous repair).

E.1.3.2 *Inclusion in a Reliability Centered Maintenance Program*

Positive Aspects

- At Dresden, an acceptable use of PRA type evaluation for the HPCI was noted. Management support of maintenance was exemplified through the use of PRA techniques to analyze the HPCI system.

- At Haddam Neck, during a charging pump repair, compensatory measures to counteract the small increase in core melt frequency based upon PRA calculations were identified and implemented. Also to support the MOV diagnostic testing program, the corporate PRA staff prioritized a list of the valves to be tested.

  Safety Injection system analysis using RCM techniques was completed, and results were to be incorporated into the Calvert Cliffs maintenance program.

E.1.3.3 *Preventive Maintenance Practices*

Positive Aspects

- At Dresden, the HPCI system was the model for the plant's Maintenance Improvement Program (MIP). The MIP included upgrading of motor-operated valves and enhancement of the PM program, failure analysis, work planning preparation and scheduling, post-maintenance testing, and communications. The HPCI system, as the "model system," was enhanced in terms of maintenance procedures, technical support, material condition, and overall appearance and performance.

  The overhaul program for all MOVs included: a complete inspection; motor resistance testing; lubrication of the main gear case; limit switch, and valve stem; and proper torque setting. Permanently mounted stem force sensors were also installed. At Unit 3, based on problems experienced at Dresden 2, new five-vane impellers were installed on the HPCI booster pump to reduce noise and vibration levels. Similarly, a HPCI auxiliary oil pump was also scheduled to be replaced.

- At Perry, the NRC reviewed ten completed electrical work orders. One included replacement of the motor for the HPCS pump. The work packages reviewed were generally made details of procedures used and the PMT performed.

- At North Anna, in response to operational problems at another plant, safety related modifications were incorporated into the suction headers of the HHSI system pumps.

Negative Aspects

- At Cooper, a failed actuator motor for a HPCI MOV was discovered while restoring electrical grounds on the 250 VDC bus supply. The MOV PM program did not include adequate tests to discover this type of failure.
- At Fermi, inadequate precautions to protect HPCI equipment during refuelling resulted in damage to instruments and conduits.
- At Palisades, there was a high failure rate of Safety Injection Tank level alarms because of a failure to take timely action to resolve problems.
- At H.B. Robinson, plant procedures lacked acceptance criteria for inspection of check valve internals for wear and degradation. There was neither a surveillance nor a PM program for several SI systems.
- At South Texas, while performing PM on the CCW to Charging Pumps MOVs, the NRC noted that the cover gasket of the limit switch/torque switch was degraded, resulting in an EQ classified MOV not being sealed.
- At Yankee Rowe, missing or improperly installed bolts and support brackets were discovered on the flow transmitter for the Safety Injection System.
- At H.B. Robinson, the NRC review of completed work requests for the SI system revealed a lack of guidance for determining preventive maintenance requirements, testing which failed to demonstrate the effectiveness of corrective maintenance, and inadequate involvement of system engineers in reviewing completed work requests.
- At Cooper, the Equipment Data File for HPCI was not verified to include all components subject to maintenance history and spare part coverage.

E.1.3.4 *Incorporation of Vendor Recommendations*

Negative Aspects

- At H.B. Robinson, several IEEE standard good maintenance practices for motors were not performed on the SI system, including thermography and monitoring of power, winding temperature, and bearing temperature.
- At Duane Arnold, inconsistent incorporation of vendor recommendations, including maintenance and testing, were identified during a utility-initiated SSFI of the HPCI system. Technical justifications for omitting the recommendations were not provided.
- At Cooper, the NRC noted excessive grease leakage from the coupling of the HPCI turbine/pump shaft. This was caused by use of incorrect vendor instructions. The utility did not determine the root cause nor evaluate whether other components might be affected.

E.1.3.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Yankee Rowe, two SI MOVs were tested using MOVATS. The test procedure incorporated relevant NRC information pertaining to MOV testing.
- At H.B. Robinson, charging pumps were included in a vibration analysis program using a sophisticated technique which evaluates velocity and displacement of vibration. Stand-by safety-related SI pumps were monitored under a less sophisticated program as specified by the ASME Code, Section XI.
- At South Texas, trending forms for leakage tests of SI check valves were used to predict if measured leakage was approaching the acceptance limit.

- At River Bend, in response to NRC Generic Letter 89-10[4], a diagnostic testing program was initiated for MOVs, as a followup to NRC Bulletin 85-03[5]. This program resulted in testing 22 HPCS and RCIC valves.

Negative Aspects

- At La Salle, LER 88-019 indicated that because of worn parts, the 1B EDG output breaker did not close in the required 13 seconds. The same parts were not inspected in the 2B EDG or the HPCS output breakers. The utility had not followed the work control process system and no technical justification had been performed for not doing so.

- At St. Lucie 1 & 2, only continuously operated equipment was subjected to vibration analysis. ASME Section XI vibrational surveillance was not an adequate substitute for vibrational analysis performed as part of a PM program.

E.1.3.6 *Post Maintenance Testing*

Positive Aspects

- At Dresden, PMT requirements for HPCI pumps and MOVs, such as valve stroking, current limit switch signatures, and VOTES diagnostic tests were appropriately specified.

- At North Anna, MOVATS was used to test a charging system MOV following installation of a new torque switch, as specified by the manufacturer.

Negative Aspects

- At Millstone 2, the NRC noted inadequacies in the acceptance criteria for preventive maintenance testing, including "normal packing leakage" for repair of packing of a charging pump.

E.1.3.7 *Root Cause Analysis*

Positive Aspects

- At Hatch, a review of the root cause analysis program for the HPCI system showed satisfactory resolutions.

Negative Aspects

- At Duane Arnold, repeated corrective maintenance of the HPCI system was noted due to the inadequate application of root failure cause analysis from self-initiated SSFI.

- At Hatch, no root cause failure analysis was performed for a failure of a HPCI MOV.

- At Calvert Cliffs, as a result of the root cause analysis program, longer term solutions to recurring leaks in the LHSI pumps were recommended, as opposed to simply replacing gaskets.

- At Millstone, a continued increase in repair frequency for charging pump packing was noted.

- At Cooper, management was unable to determine the cause of incorrect vendor information for maintenance of a HPCI pump and were also unable to conclude whether other components were similarly affected.

E.1.3.8 *Configuration Control*

- At North Anna, a project to update documents for configuration management and design basis was started for the SI system to establish plant physical configuration and to obtain information on component design.

E.1.4 Service Water System

E.1.4.1 *Specific Aging Insights*

Positive Aspects

- At Salem, the SW piping was replaced with 6% molybdenum stainless steel because of extensive deterioration of the SW system. Deterioration included thru-wall leaks at weld joints of unlined carbon-steel piping, microbiological corrosion of 316 stainless steel piping, deterioration of the lining from abrasion, and control valve cavitation. SW system piping was rerouted to reduce turbulence and stagnation.

- At Haddam Neck, aging and system upgrade items for the SW system were identified and evaluated for future action.

- At Millstone, the SW system piping was upgraded at all three units.

Negative Aspects

- At Calvert Cliffs, the SWS strainer shift valves for the internal parts of the ECCS pump room coolers were severely corroded.

- At McGuire, leakage was observed on the SW system valves.

- At Cooper, four booster pumps in the residual heat removal service systems had slight oil leaks.

- At Millstone 1, a SW pipe flange adjacent to the drywell was rusty.

- At Millstone 2, there was rust on the SW piping and supports in the pipe chase.

- At North Anna, the SW system pump house needed cleaning and painting.

- At Riverbend, the standby service water shafts and coupling were rusty. Also, the service water piping and pipe supports in two tunnels showed external rust from lack of paint. Six of ten SW boot seals in one tunnel contained rainwater that had seeped through deteriorated construction sealing between buildings.

- At Zion, the SW lines, flanges, nuts and bolts inside containment were badly corroded and had never been painted.

E.1.4.2 *Inclusion in a Reliability Centered Maintenance Program*

Positive Aspects

- At Calvert Cliffs, a SW system safety analysis using RCM methodology was completed and the results were to be implemented.

- At Ginna, a pilot RCM program was implemented for SW pumps.

- At D.C. Cook, RCM was implemented for the SW system.

- At Limerick, the PRA was updated to include the sharing of the essential service water system and is being used to schedule system outages.

E.1.4.3 *Preventive Maintenance Practices*

Negative Aspects

- At Palisades, there was a delay in inspecting, cleaning, and rebuilding all Service Water System valves manufactured by Allis-Chalmers.

- At H.B. Robinson, a loose or missing thread on a fastener caused a loose motor conduit on a SWS pump.

- At North Anna, PM activities that should be intensified were identified to avoid similar problems encountered with the SW system at Surry.

- At Salem, the SW header piping was recoated with Belzona-R Mastic, but there was insufficient time for curing at the ambient temperature. Also, improper make-up of the flange joints for the SW connection to the CCW heat exchangers was noted. An air-operated wrench was used, despite discouragement from the procedure, and no consideration was given to the tightening sequence or torque requirements.

- At Limerick, no chemical treatment was being applied to the ESW spray pond, so the ESW piping and valves became filled with sludge and scale.

- At Indian Point 2, a three-year-old work order to replace a SW pump discharge check valve was continually delayed to non-outage times. The NRC noted that such repairs were best performed during plant shutdown.

E.1.4.4 *Incorporation of Vendor Information*

Negative Aspects

- At H.B. Robinson, approximately one-half of the IEEE standard for maintenance good practices for the SW pump were not performed, including thermography and monitoring of power or current, bearing temperature, and winding temperature.

- At H.B. Robinson, the vendor's recommendations on SW booster pumps were not incorporated into the PM program.

- At North Anna, the vendor's technical information for the SW system was not incorporated into plant procedures and activities.

- At Shearon Harris, the PM program for ESW pump did not incorporate the vendor's maintenance requirements.

E.1.4.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Ginna, monthly records were maintained of monthly vibration monitoring for all SW pumps.

- At H.B. Robinson, preventive maintenance vibration tests and bearing temperature for the SW system booster pump were properly performed. Also, there was an informal vibration analysis program that uses a sophisticated technique to evaluate both the velocity and displacement of vibration for SW system components.

- At McGuire, major SW heat exchangers were monitored quarterly using differential pressure measurements. Prompt maintenance actions corrected performance degradation caused by lake turnover (mechanical tube cleaning).

- At Indian Point 3, vibration analysis and pump differential pressure were used to monitor SW pumps. Also, trending was performed for equipment such as SW pumps which demonstrated reliability problems in shaft wear caused by packing problems.

- At Salem, three material test loops were installed in the SW system to monitor different conditions of flow, ambient and heated stagnant water.

- At Fitzpatrick, QC personnel video taped the valve internals and adjacent piping using state-of-the-art fiber optic equipment during the assembly of various SW system check valves.

Negative Aspects

- At Haddam Neck, a 6 in. SWS check valve was disassembled and found to be stuck open. Three other similar valves were disassembled, inspected, and repaired. Clarification on the use of non-conformance reports was needed so significant deficiencies could be identified, corrected, and trended.

- At H.B. Robinson, procedures for the discharge check valves of the SW booster pump lacked inspecting the criteria for valve internals for wear and degradation. There was neither a surveillance nor a PM program for the valves. Check valves were not tested or maintained unless the valve was degraded or was required by ASME Code, Section XI.

- At McGuire, the response to concerns about check valves identified by INPO and EPRI, though adequate, did not include specific inspection criteria for the SW system, such as dimensions to be measured and recorded and a failure to compile quantified wear and degradation data to adjust PM frequency.

- At Cooper, a leaking solenoid pilot valve in the SW system was identified as a significant condition adverse to quality, but a non-conformance report issued pertaining to it had not been issued.

E.1.4.5 *Post-Maintenance Testing*

Negative Aspects

- At Cooper, inadequate post maintenance testing was cited in maintenance on the SW system. Though addressed by procedures, maintenance was inconsistently implemented. Inadequate or ambiguous PMT specifications resulted from poor control of work scope, poor instructions, and poor job documentation.

E.1.4.6 *Failure Trending*

Negative Aspects

- At River Bend, two standby service water MOVs were reviewed for equipment history and were found to have no records; several other components had entries under more than one mark number. The utility's equipment history data was of limited value.

E.1.4.7 *Root Cause Analysis*

Positive Aspects

- At Ginna, a comprehensive action plan was in effect to investigate and implement changes to improve reliability of the SW system.

- At H.B. Robinson, the root-cause analysis of a flow failure of a heat exchanger cooled by the SW system was thorough and accurate.

Negative Aspects

- At Palisades, the analysis and methodology for evaluating sources of SWS vibration were inadequate.

- At McGuire, frequent failures of the SW system control valves for the Component Cooling Water heat exchangers were identified by maintenance technicians rather than through engineering evaluations.

- At Cooper, a wetted solenoid pilot valve in the SW system was identified as an example of equipment degradation which did not result in a root cause analysis because there was no clear "trigger" mechanism beyond that identified in plant procedures.

- At Indian Point 3, failure analysis of a ten-inch containment penetration of the SW return line from a fan cooler unit did not correctly determine that it was due to stress corrosion caused by chlorides in the SW.

- At Limerick, the size of the ESW piping was increased to account for aged piping. The fouling factors used in the calculation did not adequately model actual flow conditions. Based on limited data from Peach Bottom, it had been estimated that SW fouling should not have posed a problem until after fourteen years of operation.

- At Limerick, the full effectiveness of chemical treatment of the SW system was not known, because certain service water piping, which was replaced after the start of chemical treatment, was due to be inspected. The full impact of corrosion on SW components was not fully considered, because inspection revealed that several ESW check valves had restricted disc travel due to the buildup of corrosion.

- At Vermont Yankee, although data on SW pump performance was tracked and analyzed, failures showed a steady increase, with no long-term program in place to reverse the trend. Plant and corporate management were not informed about the problem.

- At Indian Point 2, the repair procedure to replace a SW pump strainer contained required entries for a listing of replaced components, and the extent of damage for each component. This information was not given and the lack of information was accepted by plant personnel without further investigation.

E.1.4.8 *Configuration Control*

Negative Aspects

- At McGuire, errors were noted on SW system drawings.

- At North Anna, a project to update the configuration management and design basis document was completed for SW system to establish the plant physical configuration and to obtain information on component design for major system components.

E.1.5 Instrument Air and Emergency Diesel Generator Air Start Systems and Compressors

E.1.5.1 *Specific Aging Insights*

- At Surry, six air compressors for the Emergency Diesel Generator Air Start System were being replaced because of deterioration of the valves caused by moisture and the unavailability of replacement valves. No air driers or coalescing filters were to be installed at the new compressor discharge, so that the same problems could occur again. Also, all six discharge check valves were being replaced.

Problems had been caused by water accumulating on top of the check valves passing into the air compressors. Station personnel had identified two concerns:

1. There was no program to monitor or control EDG starting air quality, and,
2. There was a high likelihood that the 18 air-start receivers, each 20 cubic feet in volume, were full of rust and scale from years of wet service.

A significant quantity of water had been observed being discharged during routine blowdown of the EDG air start system. Over **20 lbs. of rust** recently had been removed from inside the service air receiver in the turbine building. Poor air quality had also been cited as the cause for sluggish performance of one solenoid-operated valve which admits air to the EDG air starting motors.

The IA header leakage was 47 CFM. The NRC noted that the utility had not yet:

1. Serviced all accumulators to eliminate blow-by, nor
2. Walked down the system to identify and repair all leaks.

- In addition, at Surry, compressed air was supplied to the containment by four rotary water seal ring compressors (two per unit) taking suction on the containment (99% relative humidity at 118°F), then discharging into refrigeration air driers, which were **not** capable of maintaining a 35°F dew point even under optimum conditions. In 1989, two of the discharge filters were so rotted that they could not be left in place. The remaining two filters were dirty but were left in place because there were no spares. There was no record that the IA drier filters had ever been changed since installation **7 years** before. Water was found in end-use devices and high dewpoints were recorded in the Containment IA System. Water was squirting from solenoid-operated valves; flow gauges were full of water, and dew-point readings were greater than 60°F.

- Also at Surry, there were numerous examples of end-use devices which vibrated during normal operation that were connected to stationary IA root valves by lengths of small-diameter copper tubing, despite extensive industry experience with trips and transients caused by vibration-induced air line failures. (As noted in Section 4.1.2 for Feedwater, North Anna tripped during February 1989 when vibration caused an IA line on the MFW regulating valve to fail, coupled with the failure of a steam generator tube plug and tube rupture).

- At St. Lucie, some components such as the 1A Service Air Compressor had oil leaks, the sources of which were unidentified.

- At ANO, there was a lack of awareness of plant aging of non safety related equipment, as evidenced by numerous problems with the IA System. Numerous IA spare parts could not be used because their shelf life had expired. The utility apparently continued to use the components without refurbishing them, even though the components contained similar parts which had been in service longer than the spare parts. The NRC considered that the problem resulted from an unimplemented equipment trending program for BOP components.

- At Palisades, an emergency diesel generator could not be started during testing because the air compressor that provides starting air to the air start motors would not operate. The thermal overload on the air compressor's motor starter had tripped and would not reset. Replacement of the thermal overload did not correct the problem.

- At McGuire, the control valves of the Nuclear Service Water System for the Component Cooling Water heat exchangers frequently failed to close properly. Closure of these valves assists maintenance. Failure of the air lines to a valve actuator had made the valves inoperable, a more serious concern. Pending replacement of these valves, the utility had increased

PM activities. However, the frequent failure of these valves had been identified by the maintenance technicians, and not by an engineering evaluation.

- At North Anna, although the IA system appeared to be properly operated and maintained, there were missing handles on instrument root valves, cracked instrument face glasses, and severely bent IA lines to air-operated valves.

- At Sequoyah, the general material condition of the Compressed Air System was satisfactory. However, a flexible conduit for an oil level switch was loose, oil accumulation was found on the stuffing box of one compressor, and drier desiccant was found on the concrete mounting pad of a compressor.

- At Cooper, moisture was observed in the filter housing of a Service Air System filter housing in a supply line to the Reactor Water Cleanup System filter/demineralizer. When the filter was in service, 1000 PSI reactor water leaked through two manual valves and a check valve. The SAS was also the Breathing Air System. There was no regular testing program for the Breathing Air System.

- At Haddam Neck, some EDG Air Start System spare parts, which may have been needed, were not available on site because of a lack of a Bill of Material for this equipment. The NRC concern was about availability in general.

E.1.5.2 *Inclusion in a Reliability Centered Maintenance Program*

- At Dresden, the NRC noted that one aspect of RCM included in mechanical maintenance was the use of sonic equipment to identify air leaks.

- At Calvert Cliffs, several safety system analyses using RCM methodology had been completed, but the results were not scheduled for implementation until the end of 1990. The systems included the Instrument Air Drier System.

- At Haddam Neck, a pilot program had been implemented for several systems, including the Service and Control Air compressors.

E.1.5.3 *Preventive Maintenance Practices*

<u>Positive Aspects</u>

- At Millstone 1, the IA system was being upgraded.

- At McGuire, the NRC considered the utility's actions PM and corrective maintenance on the IA System to be a strength.

<u>Negative Aspects</u>

- At Shearon Harris, there were no formal PM, maintenance, operations, or surveillance procedures for the Rotary Air Compressor, even though the compressor was supplying 100% of the station IA requirements. The vendor recommended regular PM for both the compressor and the air drier.

  The IA system was blown down biweekly. However, there was no PM on the inline air filter.

- At Fort Calhoun, there was no PM on air-operated valves.

- At St. Lucie, the utility had installed high efficiency filters at the discharge of each IA drier. Sensitive equipment, such as Bailey positioners and solenoid valves, were also equipped with upstream filter-regulators. However, there was no regular PM changeout schedule to replace the filter-regulator filter elements, and they were only changed if clogged.

- At Waterford, there was only a generic procedure for corrective maintenance on safety and non-safety related equipment such as compressors.

- At H.B. Robinson, no PM had been established for the refrigerant air drier at the discharge of one of the IA System compressors, nor were important vendor requirements incorporated into the PM procedure for the compressor itself. The vendor manual also stated that the importance of establishing a wear rate for the teflon wear and seal rings "...cannot be overemphasized...". The consequences of worn rings are first, decreased efficiency, and subsequently, contact between the piston and cylinder which results in immediate and expensive damage to the finely honed cylinders.

- At McGuire, there was no regularly scheduled PM for the filter-regulator for valves which required and received design verification of failure position as accident mitigation devices, as specified in NRC Generic Letter 88-14 on IA systems[6].

E.1.5.4 *Incorporation of Vendor Recommendations*

Positive Aspects

- At Sequoyah, the NRC determined from a review of five vendor manuals, one of which concerned compressors, that the manuals were being controlled, updated, and used to conduct preventive maintenance.

Negative Aspects

- At St. Lucie, the vendor for the new IA system compressors recommended retorquing the crosshead bolts after 6 months or 2000 hours of operation. This requirement was not included in the appropriate PM procedure, nor was any justification given for not torquing the bolts. Therefore, the Unit 1 compressors were nine months overdue in being torqued.

- At LaSalle, the Air Compressor of the 1B Emergency Diesel Generator Air Start system continued to blow head gaskets shortly after each repair. The vendor advised using different torque values to prevent this. Only two of five work orders reviewed by the NRC identified the torque wrench used and stated that the bolts had been torqued to the specified values.

- At Clinton, an engineering evaluation of the vendor manuals for the emergency diesel generator determined that 14 additional PM tasks should be completed on all of the diesels start up, such as inspection/cleaning of the air-start solenoid valves and the air-start lubricators. The air-start motors had not been properly maintained, as recommended by the vendor.

E.1.5.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Indian Point 3, the IA compressors were among the components subjected to thermography.

- At Surry, leak testing was performed on the IA check valves which supplied air to the solenoid-operated valves, which, in turn, open the steam admission valves of the Auxiliary Feedwater pump turbine.

- At Haddam Neck, several actions had been taken in response to NRC Information Notice 88-24[7], including replacement of several solenoid valves used to isolate the containment. In response to NRC Generic Letter 88-14, the utility tested all safety-related air-operated valves to verify that they would fail in the required safe position following loss of air supply. Maintenance had been instituted for boundary components such as pressure regulators between the air supply system and the safety-related component, and a procedure to detect contaminants had been implemented.

- At H.B. Robinson, in response to NRC Generic Letter 88-14, the utility verified air quality requirements for individual components served by the IA System, and verified IA quality by determining its hydrocarbon content, dewpoint, and particulate content.

- At Cooper, in response to NRC Generic Letter 88-14, the utility appeared to have adequately followed the recommendations and performed the verifications.

Negative Aspects

- At Nine Mile Point 1, the In-Service Testing program for Instrument Air did not assure fail-safe capability of non safety-related air operated valves upon loss of air. The number of valves to be surveilled was to be increased from 6 to 130.

- At Waterford, no technical acceptance criteria were identified in the PM for the minimum capacity of the Instrument and Station Air compressors. In response to Generic Letter 88-14, flow capacity tests of the A and B Instrument Air compressors were performed in December 1988, which showed capacities of 50% and 65% respectively.

- At H.B. Robinson, while the utility verified air-quality requirements for individuals components served by the IA system, and verified IA quality by determining its hydrocarbon content, dew-point, and particulate content, the NRC noted that the particulate size and distribution were not determined. The NRC considered particulate size in the IA System as important because air quality for end-use devices is frequently defined by maximum particulate size. The NRC noted that the Shearon Harris site used a laser scanner to characterize particulate content. Also, three MSIV IA accumulator check valves, required to maintain the MSIVs in the closed position, had not been included in the ASME Code Section XI test program. Functional tests of these valves were performed under another procedure, but only for rapid closure, and not for the ability of the valves to seat and seal under slow loss of IA conditions.

- At McGuire, there had been no loss-of-air testing for some of the Main Steam Isolation Valves at both units since pre-operational testing. Also, no testing of MSIV accumulator check valves had been completed or was planned.

- At Cooper, the utility's response to NRC Generic Letter 88-14 was satisfactory, but the NRC noted that there had been no effort to expand the scope to similar systems beyond what was required, such as applying the information to the Service Air System.

E.1.5.6 *Post Maintenance Testing*

Negative Aspects

- At St. Lucie, PMT was applied only to major non-safety related equipment, including IA compressors. There were no test methods or acceptance criteria associated with such equipment. The specific instructions were limited to "...test run and check for seal leakage...". The acceptance criteria were "...run a sufficient amount of time to determine if it performs its intended function...".

- At Waterford, a capacity test on air compressors following overhaul had only recently been required.

- At Sequoyah, PMT of an IA system drier was conducted when the drier was returned to service, but the testing was not recorded on the work closure form.

- At Cooper, an example of omitted PMT was cited for the IA driers.

E.1.5.7 *Failure Trending*

Negative Aspects

- At LaSalle, the utility published a quarterly report which identified the number of completed work requests which required rework and gave the reasons. There were five failures within two months of the head gasket of the 1B EDG air-start motor air compressor. Such failures had not been identified as rework because the rework only identified failures which occurred during post-maintenance testing. The utility was in the process of changing the rework program to the Failure Analysis Program which uses PADS (Problem Assessment Data Sheet).

- At Rancho Seco, the method to determine NPRDS reportable failures appeared to contain potential oversights and omissions. Examples included incomplete or missing entries of the IA system check valves. A non-conformance report was not written when debris had caused two IA check valves to fail during the performance of a special test procedure. The generic implications of the problem was not recognized, nor the risks of using sealing tape on threaded joints. The NRC cited this as a failure violation.

- At Cooper, for some systems and plant areas, including the IA drier, and the Equipment Data File had not been verified, so that not all components were included and provided a maintenance history.

E.1.5.8 *Root Cause Analysis*

Positive Aspects

- At Fitzpatrick, the NRC cited, as an example of properly conducted root cause analysis, an ongoing evaluation, including laboratory tests, to resolve problems experienced with the IA System.

- At Waterford, in addition to compiling a history file for all components, a root cause evaluation of all failures was conducted. The intent was to extend the operating life of a component or quantify failure information to predict when a component will fail again. Examples were the low flow of the Instrument and Station Air Compressors and premature compressor degradation.

- At Cooper, while deficiencies in root cause analyses were noted for other cases, the NRC cited the root cause analysis for an Instrument Air drier failure as being extensive and rigorous. Specifically, an IA drier post-filter housing had ruptured, causing a loss of IA pressure. The rupture occurred when temperature controls failed, overheating the filter housing, and igniting the filter media. The loss of air caused the MSIVs to drift closed, resulting in a full reactor scram. The causes were attributed to absence of PM for temperature switches, excessive use of sealant and lubricant, failure to specify the use of high-temperature filter media, and inadequate training. Corrective actions included closer monitoring of driers via operator logs, drier operations training, evaluation of drier design for improvements, and possible PM and operational checks.

Negative Aspects

- At McGuire, the NRC's review of historical data for IA compressors and driers indicated a problem with entering the failure cause codes for equipment in the work requests.

E.1.5.9 *Configuration Control*

Positive Aspects

- At North Anna, the IA System was one of the systems selected as part of a project to update the configuration management and design-basis document which had been started in 1988 to establish plant physical configuration and obtain information on component design for major components.

Negative Aspects

- At McGuire, several drawing errors were noted, including one in the IA System.

E.2 Components

E.2.1 Emergency Diesel Generators

E.2.1.1 *Specific Aging Insights*

Positive Aspects

- At La Salle, the solenoid discharge valves for EDG fuel oil transfer pumps were upgraded with improved internals such as Viton "O" rings instead of EPDM "O" rings which were incompatible with fuel oil. The valves had stuck in either the open or closed position.

- At Ginna, major recent initiatives in plant maintenance included an overhaul of both EDGs, and replacement of a station battery and a Reactor Coolant pump motor.

Negative Aspects

- At Palo Verde, there had been three redundant trips of the Unit 2 EDG on high temperature during the engine cooldown mode, which is a five-minute unloaded run after operation. The probable cause was a faulty check valve in the air control system of the jacket water high temperature trip.

- At Clinton, oil leaked from the lube-oil lines of all three EDGs. Similarly, at River Bend, oil leaked from both the Division I and II diesel generators, and less severely from the diesel generator of the High Pressure Core Spray (HP-CS) pump motor.

- At Fitzpatrick, some gaskets used with two safety-related EDG pressure switches had been obtained from a maintenance supervisor, rather than from a warehouse. Because large quantities of materials were purchased for Direct Turnover, i.e. they are not stored in the warehouse but are given directly to the requesting organization, the NRC was concerned that the procedure controlling the storage, distribution, and restocking of safety-related materials no longer applied. The NRC considered the probability of damage as minimal if the equipment was used quickly, but the storage time and conditions are particularly important for materials having a limited shelf life.

- At Palisades, the NRC noted a small water leak from the flange connection of the jacket cooling water heat exchanger of an EDG.

  Also, a flow switch for an EDG lube oil heater had been incorrectly bypassed for at least eight months. The Lube Oil Priming Pump runs continuously whenever the EDG is operable, circulating heated oil through the heater to the upper engine block and to the bearing upper cylinder to aid in fast startup. According to the system engineer, if the flow switch is bypassed, under certain conditions, the engine would be "...stressed causing accelerated aging and possibly harder starts, but it would start...".

E.2.1.2 *Inclusion in a Reliability Centered Maintenance Program*

- At La Salle, the philosophy of the electrical maintenance included some concepts of RCM, as exemplified by the analysis of EDG lubrication oil.

- At Fitzpatrick, risk had been considered in various situations, such as the use of fault tree analysis to examine the need for an EDG fuel cut-off valve.

E.2.1.3 *Preventive Maintenance Practices*

Positive Aspects

- At Millstone 1, there was a program for dewatering the EDG fuel oil storage tanks and controlling oxidation and bacterial growth. The diesel oil was tested monthly.

- At Calvert Cliffs, PM on the protective relaying of the logic circuits on an EDG, and PM on 480 V breakers and battery systems was satisfactory.

Negative Aspects

- At Palisades, the threads on the terminal lugs for an EDG Excitation Panel were not completely engaged. This deficiency was cited as a violation by the NRC.

- At Dresden, the EDG 2,3 and 2/3 excitation field breakers (and the Reactor Protection System breakers) were not included in the PM program.

- At Limerick, following a 24 hour endurance test of an EDG subsequent to overhaul, the machine did not properly control voltage or frequency when not parallel to the grid. The problem was insufficient venting of air from the governor.

- At Fort Calhoun, there was no periodic program to test or replace flexible hoses in the EDG System.

- At Cooper, contrary to plant Quality Control procedures established to implement 10CFR50, Appendix B, maintenance had been performed on one of the EDG cams which included critical reassembly steps, critical measurements and clearances, and verification of valve timing and timing clearances without QC inspection of these activities.

E.2.1.4 *Incorporation of Vendor Recommendations*

Positive Aspects

- At Vermont Yankee, the EDGs were not barred over (turned or cranked with no intention to start) following a 3 minute run, contrary to the manufacturer's recommendations. The Technical Specifications required demonstrated operability following any action or event rendering an EDG inoperable. In response to NRC concerns, the utility agreed to adopt the manufacturer's recommendations to do an "air roll" after shutdown to enhance reliability and longevity.

- At Indian Point 2, in the beginning of the refueling outage during which the MTI was conducted, the vendor's specified 12-year PM was performed on one of the three EDGs. Based on the positive results of this very extensive disassembly, inspection, and refurbishment of the engine and generator, the utility decided to perform a reduced PM on the other two EDGs, rather than an annual inspection as required by the Technical Specifications. The vendor agreed to reduce the extent of work to less than that required for the 12-year PM. The EDGs had been under consideration for an increase in the total kW ratings, because of previously identified loading inadequacies that could require additional PM activities.

Negative Aspects

- At Palo Verde, the utility could only produce 3 formal evaluations for 19 Service Information Letters (SILs) issued by the EDG manufacturer, Cooper Industries. There was an extensive backlog in the review of EDG SILs.

- At Salem, one of the EDG cylinder heads was removed without a special lifting ring (identified in the technical manual) designed to accommodate the non-vertical angle. Chapters were missing for the injectors, valve gear, exhaust and intake manifolds, and jacket water specifications which would have shown the torquing and clearance specifications.

- At Clinton, the utility conducted a study of the PM tasks recommended in the EDG vendor manuals. Forty-seven percent (47%) of the electrical and thirty percent (30%) of the mechanical PM tasks had not been included in the established PM program. An engineering evaluation determined that 14 additional tasks should be completed on all of the EDGs before startup, including an annual overspeed trip test.

- At Indian Point 2, the system engineer reviewing the EDG manuals had identified numerous discrepancies in setpoints and logkeeping.

- At Cooper, the tell-tale drain on an EDG intercooler had been leaking, suggesting there was a leak in the Service Water system. The vendor determined that the corrosion was so extensive that the intercooler should be replaced. The vendor's information reviewed by the NRC indicated that the "aftercooler" should be drained and flushed every 4 to 6 months to keep the coolers clean and to prevent clogging. This recommendation was not in the utility's PM procedure, nor had the other three intercoolers been inspected.

E.2.1.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Indian Point 3, the exhaust gas of the emergency diesel generators was monitored for degradation. The lube oil also was chemically analyzed for water vapor.

- At Shearon Harris, the EDGs were one of only three components, the others being Reactor Coolant pumps and charging pumps, whose lube oil was analyzed. Other components were being added.

- At Vermont Yankee, scratches were found on two camshaft lobes during an inspection of an EDG in late 1987. A special monitoring program was begun to detect deteriorating performance, i.e., changes in cylinder temperature. None were noted, but the camshaft and associated parts were replaced.

- At Grand Gulf, trending was performed for EDG problems, as well as for motor megger readings, battery cell specific gravities, lube oil analysis, vibration and problems with Engineered Safety Features room coolers.

Negative Aspects

- At Hope Creek, EDG oil samples were taken from a stopped engine, downstream from a filter, rather than from a running engine, before filtration.

E.2.1.6 *Post Maintenance Testing*

Positive Aspects

- At Calvert Cliffs, PMT was performed on the protective relaying of the EDG logic circuits, as well as of 480 V breakers and battery systems. Subsystem testing of the EDG logic circuits and the 480 V breakers was postponed until the system test.

- At Haddam Neck, the NRC observed PMT of an EDG following troubleshooting of a recurring start-failure alarm. Appropriate PMT requirements were specified, equipment was restored to normal configuration, and the PMT was conducted before acceptance for operation.

Negative Aspects

- At Indian Point 3, one of the EDGs had failed to start because of low lube oil pressure. The cause was attributed to failure to conduct PMT following calibration of the pressure switches.

- At Cooper, there were instances in which appropriate PMT had not been performed; for example, maintenance on the EDG local control panel.

E.2.1.7 *Failure Trending*

Positive Aspects

- At Indian Point 3, the utility had implemented the Component Engineer concept, e.g. valve packing was monitored by the same engineer for all systems. For complicated tasks, such as the EDG PM, several component engineers may be involved, with one engineer assigned responsibility for the entire task.

Negative Aspects

- At Haddam Neck, engineers had both system and project assignments. Problems associated with the EDGs, Condensate System, and AFWS were all handled by the same engineer, delaying the resolution of problems with an EDG.

E.2.1.8 *Root Cause Analysis*

Negative Aspects

- At Palo Verde, one of the EDGs was run with a known oil leak in a cylinder head for 18 hours (out of a 24-hour test) when it had to be shut down. No engineering analysis had been done to determine whether the diesel could run with the leak. Also, the utility identified numerous failures of elbow fittings and drain plugs in the EDG jacket water system caused by corrosion. After replacing several of the parts, more of the same parts failed which the utility had not identified as being vulnerable to corrosion. The utility's failure to take aggressive action to resolve the problems was cited as a violation by the NRC.

- At Duane Arnold, the utility failed to take prompt corrective action or perform a root cause analysis for problems with the thermal overloads of the EDG jacket cooling pump motors and associated contacts which protect the motors from excessive fault currents. There were no sizing criteria for thermal overload, and design documents were not updated for changes in heater size. The NRC cited this failure to take action as a violation.

- At Cooper, the utility relied on reviews by systems engineers and supervisors of work activities and documents to identify conditions requiring escalation to management or additional evaluation or corrective or preventive actions. The following examples were cited:

(1) Conditions adverse to quality were encountered but were not cited as requiring further evaluation and corrective or preventive action.

(2) Significant conditions adverse to quality were identified, but a nonconformance report (NCR) was not issued.

Specific examples included the failure of an EDG intercooler. Root cause analyses were not performed for any of the problems because there was no clear "trigger" beyond that identified in the plant procedures.

E.2.1.9 *Configuration Control*

- At Palisades, use of an incorrect revision of a drawing to modify circuit hardware in an EDG control panel was cited by the NRC as a violation.

- At Cooper, replacement of an EDG cast boss in a cam bearing housing by stainless steel tubing was treated as a repair, and not as a design change requiring review under 10CFR50.59 for safety impact. The appropriate drawings were not changed either.

E.2.2 Electrical Components: Breakers, Switchgear, Relays and Motor Control Centers (MCCs)

E.2.2.1 *Specific Aging Insights*

Positive Aspects

- At Rancho Seco, the NRC noted that the physical condition of equipment physical condition, such as electrical switchgear, appeared to be excellent. There was no obvious moisture or foreign material on interior plant electrical controls, and circuit breakers were in their proper position.

- At Sequoyah, early in plant life, there were failures of the main toggle link pin in 6900 VAC circuit breakers. PM procedures had been revised to include inspection and replacement of the pin if cracks were found.

  Also, in response to NRC Information Notice 88-11[8] on the widespread failure by corrosion cracking of silicon bronze bolts used to splice bus bars in MCCs manufactured by GE, as noted at one nuclear plant, the utility determined from sampling that such bolts did not exist in its MCCs and 480 VAC switchgear.

Negative Aspects

- At Duane Arnold, there was an untimely response to a manufacturer's service advice letter issued in 1979 on premature wear of Tuf-LOC Teflon-coated fiberglass sleeve bearings in certain types of GE 4160V circuit breakers. The affected components involved the Residual Heat Removal (RHR) pumps, Reactor Recirculation pumps and other safety-related breakers.

(1) The RHR pump circuit breakers had been inspected in 1985 and replacement was recommended; replacement did not occur until 1987.

(2) At the time of the MTI, only 6 of approximately 50 breakers had their bearings replaced. The remaining 44 breakers included 19 that were safety-related.

(3) There had been continued identification of worn-out bearings, in one case, involving a Reactor Recirculation pump breaker.

These examples were cited by the NRC as part of a violation. Similar failures attributed to worn bearings were identified at other plants.

In contrast, the NRC noted that at Dresden, there had been a strong resolution of the Tuf-Loc bushing problem.

- At Dresden, on February 25, 1988, the station's technical staff reported that General Electric SBM switches used in 4160 VAC breakers and cubicles were at or near the end of life, based on increased failure rates. The staff also noted that the SBM switches were not included in the PM program and their performance had not been checked. The NRC determined that 15 SBM switches for some 4160 VAC breaker switches had been replaced, based on failure of the switches to meet acceptance criteria defined in revised PM procedures. The switches that passed would not be inspected for another 3 years, the PM frequency on the 4160 VAC breakers, even though the switches had a long history of failure and were at or near the end of life.

  The utility had been aware, since at least July of 1987, of four events at another nuclear plant which involved failures of 4160 VAC breakers to transfer on demand, the same type of breakers used at Dresden. In each event, voltage to a 4160 V bus was lost when an alternate feeder breaker failed to automatically close after the normal feeder breaker was opened. The failures had been caused by hardened grease and dirt in the stationary auxiliary SBM switch linkage within the normal feeder breaker compartments. The failures were significant because the stationary auxiliary SBM switch in a normal feeder breaker to a safety-related bus could prevent restoration of voltage to the bus from the alternate or emergency source upon a loss of offsite power. The NRC cited this as a part of a violation.

- Also at Dresden, a 125 VDC MCC battery to the main bus breaker handle in Unit 2 was indicating approximately 3 inches away from the ON position, even though the breaker was energized. The NRC inspector was told that when the breaker trips, the handle would then point towards the ON position and that was a known problem with these types of breakers.

- At Prairie Island, the 4160 VAC bus connecting a transformer to Bus 11 and 12 switchgear was corroded. The corrosion resulted in severe overheating of the lower bus bars. Copper connections also appeared to contribute to the corrosion as the switchgear bus sections were aluminum. No non-conforming item reports had been written. The NRC cited this as a violation.

- At Nine Mile Point 1, there was a high failure rate of EPA 600 VAC breakers.

- At Palo Verde, numerous work orders were associated with the replacement of Potter-Brumfield relays installed in the Reactor Protection System as NSSS and BOP Engineered Safety Features Actuation System initiation relays. In LER 528/88-018, the utility reported that numerous Potter-Brumfield sub-group failures had occurred, which would have prevented proper rotation of the relay spring upon being deenergized by a valid safety system actuation signal, and would have prevented associated valves and pump motors from operating as required for a safe plant shutdown.

Also, the NRC was concerned that only one of five spare reactor trip breakers on site for the three units was available for use. The other four were in various stages of repair. According to the utility, it was very difficult to obtain replacement reactor trip breakers or spare parts from the original manufacturer because the breakers were no longer manufactured. However, the utility had recently reached an agreement with General Electric to rework existing breakers (two in each of the three units, plus five spares) to the specifications of certified Class 1E reactor trip breakers. The NRC was still generally concerned over the availability of spa. lacement reactor trip breakers or parts.

- At Zion, a DC battery to bus circuit breaker failed to close several times on the first attempt. The manufacturer identified worn bearings as the probable cause.

- At Maine Yankee, the NRC noted that the utility had not reviewed their procurement practices and use of Agastat relays purchased as commercial grade items, as had been recommended in NRC Information Notice 87-66[9] (concerning inappropriate application of commercial grade components). The NRC stated that the utility should review the issue and determine whether commercial grade Agastat relays had been used in safety-related applications, and take any necessary action.

- At Clinton, hydraulic fluid from the operation mechanisms in the cabinets of two 345 kV breakers was observed leaking onto cables at the bottom of the cabinets. There were loose bolts and/or dirt in other breaker cabinets.

- Also at Clinton, in one of the four warehouses, the environmental controls were not as effective as at the other three and there was no segregation of safety-related and non-safety-related parts. Heavy boxes were stacked on other boxes marked as containing delicate instruments, and open boxes and bags contained electrical relays and switches which were covered with heavy coats of dirt and dust.

- At Indian Point 2, the NRC noted two uncovered 480 VAC breakers in the switchgear area.

This was considered poor work practice and against vendor recommendations.

Similarly, while the NRC witnessed the 18 month PM inspection on a Westinghouse Type DB-50 **reactor trip breaker**, performed by both Westinghouse and plant maintenance personnel, the NRC was concerned that several breakers were left uncovered for lengthy periods after removal from their cubicles, which was contrary to both Westinghouse recommendations and utility procedures.

Also, the NRC questioned the utility's judgement with respect to safety in deferring certain maintenance actions. In one case, work orders to replace broken 480 VAC disconnect switch and breaker handles, which were required to be operated under emergency procedures, had been back-logged for several years.

- At Perry, examples of poor housekeeping were cited by the NRC which, although not appearing to have safety significance or impact plant operation, included broken handles on MCCs.

- At Calvert Cliffs, there was an air gap of approximately 1/8 in. between the track and concrete floor for all 4kV switchgear buses which had caused misalignment between the breakers and MJ switches. However, no operational or emergency condition safety concerns were associated with the problem of track sagging.

- At Haddam Neck, Switchgear Room test cables used for grounding had exposed copper. Also, there was temporary cover over a battery charger to collect condensation from the ductwork overhead.

- At McGuire, the material condition was considered average. The discrepancies were generally minor, and did not indicate any operability problems. However, the number of minor deficiencies indicated the need for improvement. Deficiencies consisted of items such as leaking valves, broken handles on valves and MCCs, corrosion on MCCs and power distribution cabinets, and loose supports.

- At South Texas, the Unit 2 Emergency Cooling Water was not well maintained. Pump room floors were covered with water, exposing electrical components such as local MCCs to high humidity and standing water.

E.2.2.2 *Preventive Maintenance Practices*

Positive Aspects

- At Indian Point 3, the PM for MOVs included the breaker.

- At Shearon Harris, during maintenance of a 6900 VAC, 1200 amp circuit breaker, the NRC observed that controlled copies of the manufacturer's instructions were brought into the workplace.

  Also, the program called for performing PM at every second refueling outage, or approximately one half of the switchgear at each refueling outage. Few circuit breakers may be conveniently serviced while the unit is at power, and these were done biannually.

- At Maine Yankee, the utility had an ongoing major project to upgrade eighty-three 480 VAC circuit breakers, mostly GE Model AK-25, as described previously in Appendix D, Section 2.1.6 of this report.

- At Waterford, the reactor trip breakers are GE Type AK-25 in which GE, according to the bearing grease may solidify after about seven years, possibly affecting the breaker's response time. The utility returns the breakers to GE for refurbishment at five-year intervals. The PM program checked the breaker's response times and these were recorded in the trending program.

  Also, the maintenance procedure for 4160 VAC switchgear required verification of torque of all exposed electrical connections, including the switchgear grounding connections.

- At Perry, the work packages reviewed were generally adequate. The description of work done contained details of the procedures used and the PMT performed. The review included a work package on replacement of relays on the Control Room HVAC supply fan.

- At Calvert Cliffs, PM on 480 VAC breakers was performed satisfactorily.

- At McGuire, the NRC reviewed the PM procedures for the 600 VAC Distribution System. The procedures were satisfactory and in accord with the vendor's general recommendations for the type of maintenance and the frequency.

  No significant problems had been identified in the maintenance of 125 VDC batteries, chargers, circuit breakers, and 120 VAC inverters, including those for the EDGs.

- At Sequoyah, the procedure for PM on 6900 VAC switchgear included nearly all the beneficial steps recognized by industry; its overall clarity and format were excellent, it had about 38 independent verification steps and invoked a special procedure aimed at reducing common mode failure caused by maintenance.

  However, the PM failed to address accepted industry practice by omitting mention of the anti-pump circuit, space heaters, blow out coil, and potential transformer compartments. Lubrication was not clearly addressed.

- Also at Sequoyah, the recommendations in NRC Information Notice 87-61[10,11] concerning W-2 cell switches in 480 VAC switchgear were incorporated into the PM procedures. As per NRC Information Notice 88-50,[12] ferroresonance in high-voltage transformers was also correctly addressed.

Negative Aspects

- At Hatch, several problems were noted by the NRC concerning the PM procedure for 4160 VAC metal-clad switchgear; these were discussed in Appendix D, Section 2.1.6 of this report.

Also, the electrical PM program did not include:

(1) Protective trip testing of MCCBs, other than containment penetration circuit breakers.

(2) Periodic visual inspection of 4160 VAC current-limiting reactors.

- At Dresden, the maintenance procedure called for the 4160VAC breakers to be inspected and overhauled every 5 years or 500 operations. However, at one of the units, breakers for two of the Containment Cooling Service Water pumps had last been overhauled in **1976.** Breakers which were important to safety, i.e., required to satisfy technical specification requirements for two sources of offsite power to be available, had last been overhauled in **1973, 1975, and 1977.** During the MTI, a 4160V feeder breaker failed to trip during an undervoltage surveillance test. The problem was a burnt trip coil caused by mechanical binding of the breaker mechanism, which had last been overhauled in **1976.**

  A 4160V breaker for a Unit 2 LPCI pump had tripped several times during pump starts in February 1988. The cause had been identified as a failure to perform PM, specifically a direct lack of lubrication on the trip latch roller mechanism.

  In addition, failure to perform PM had not been identified as a contributing factor in the failure of the Unit 3 Isolation Condenser Makeup Valve. The DC-powered MOV failure had been caused by dirt and sticking auxiliary contacts with buildup non-conductive deposits, resulting in increased electrical contact resistance. PM had not been performed on two Unit 3 250VDC Motor Control Centers since **1975.** These MCCs supply power to HPCI torus suction valves.

  The NRC cited these problems as examples of a violation.

- Also at Dresden, the NRC noted that Emergency Diesel Generators 2,3 and 2/3 excitation field breakers and **Reactor Protection System** breakers were not included in the PM program.

- At Waterford, a work order to clean and inspect some 4160 VAC switchgear required torquing of switches and exposed connections. However, the NRC noted an unauthorized deviation in that "...no loose bolts found (so) torque (was) not required...". The NRC indicated the need to evaluate the safety significance and operability of the safety related switchgear and to determine if torque requirements had been deleted in other safety-related switchgear.

- At Fitzpatrick, during NRC observation of I&C maintenance, it was noted that when an HGA relay was being calibrated, the procedure pertained to the calibration of a similar relay, type HMA. The training module for relay calibration pertained to yet another relay, type HFA. Although inappropriate, the procedure did apply to HGA relays and the latest vendor manual did not specify calibration requirements.

- At Rancho Seco, the NRC considered that specific maintenance program weaknesses included the maintenance of electrical circuit breakers.

- At H.B Robinson, the PM procedures for electrical equipment were weak and there was extensive use of a very simple checklist. The NRC considered the PM procedure for safety-related and Dedicated Shutdown System switchgear to be poor because, for example, it did not describe how to check the critical dimensions of primary contacts, nor state how to adjust them. It did not specify operating the breaker electrically from the test stand, checking charging motor brushes, nor the open/close response time nor contact resistance measurements. There was only a very brief checklist for PM of 4160 VAC switchgear. The NRC considered these deficiencies to increase the possibility of unplanned actions and unsatisfactory maintenance and equipment failures.

E.2.2.3 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Indian Point 3, exciter switchgear, MCCs, reactor trip breakers, 6900 V and 480 V breakers were among the components subjected to thermography.

  Also, an ohm meter was used to read an auxiliary switch position before and after assembly of a Westinghouse DS-416 breaker.

- At Shearon Harris, PM included nearly all of about 30 major PM steps that are typically recommended for medium voltage switchgear. Although the procedures did not call for a check of the anti-pump circuit nor a measurement of insulation resistance across the open contacts, the utility agreed to include these steps.

- At Vermont Yankee, the NRC noted that there was routine PM and testing of circuit breakers.

- At Perry, the NRC reviewed procedures for testing molded-case circuit breakers and overload heater relays and the protective relaying program. The procedures were satisfactory and were reviewed by the utility every two years for technical adequacy.

- At Haddam Neck, engineering involvement to resolve a relay setpoint change for a Heater Drain pump motor indicated that the station had a strong program for controlling setpoints.

- At Yankee Rowe, the NRC observed checks of a voltage relay for an EDG and a differential relay for the main transformer. As-Found conditions were documented for each item, and each component was tested to predetermined PMT requirements.

- At McGuire, refueling cycles were every 14 months. Each circuit breaker received a contact resistance (Doble) test and PM every third refueling outage. The maintenance program was consistent with good industry practice, except that control wiring compartments and bus compartments in the switchgear were not inspected.

Negative Aspects

- At Shearon Harris, factory testing of ITE/Siemens Type HE 480 VAC molded-case circuit breakers (MCCBs) was not performed or the tests did not detect a fault in the instantaneous trip mechanism. The utility's circuit breaker test sets did not produce a high-speed oscillographic readout to display the first cycle of current.

Also, despite the availability of the vendor's field test procedure, 125 VDC molded case circuit breakers were not tested.

- At Surry, inspection and testing of MCC thermal overload devices, motor starters, and molded-case circuit breakers had been deferred in the previous two periods because of a staffing shortage. Safety-related MCCBs were scheduled for testing every 5 years and non-safety related ones every 10 years.

- At LaSalle, LER 88-019 identified that the 1B EDG output breaker had not closed in the required 13 seconds because of worn parts. The same parts had not been inspected in the 2B EDG or the HPCS output breakers. The utility had failed to follow the work control process without technical justification.

- At St. Lucie, MCCBs were not tested. MCCBs are used exclusively in the 120 VAC/ 125 VDC power systems as circuit protective devices and disconnects in the main buses and feeder circuits. They are used in most branch circuits, except where fuses are used. In the 480 VAC power switches, metal-clad switchgear (circuit breakers) are used in the feeders and main breakers. MCCBs are used in the branch circuits.

  There was an effective PM program for the metal-clad circuit breakers. The maintenance procedure used for cleaning, lubrication, and testing breakers in the 480 VAC MCCs and load centers included instantaneous (magnetic) and long-time (thermal) trip testing to verify the breakers will perform their intended function. This procedure was partially applicable to MCCBs, yet MCCBs were not in the scheduled PM program.

  The MCCBs were not tested in any system once installed, but all replacement MCCBs were tested. The utility had an excellent test procedure for MCCBs, which referred to NEMA Standard AB2,[13] on procedures for field inspection and performance verification of molded-case circuit breakers, and which states that MCCBs have moving parts which require maintenance.

  The NRC reviewed a St. Lucie LER where a manual plant trip had been required because a 40 amp subgroup (feeder) 240 VAC MCCB tripped early on 30 amps. The utility agreed to test all of the MCCBs in the rod-drive power system at the next refueling. The testing would include holding current and at least one trip verification. Also, the rod-drive MCCBs would be placed in the PM program for periodic testing.

- Several plants, in addition to Clinton, experienced excessive failures of 345 kV switchyard type GHO SF6 breakers manufactured by Siemens Allis, Inc. A problem had also been identified with 345 kV trip coil circuits on Type LPO breakers, also made by Siemens Allis. This was described in Appendix D, Section D.2.1.6 of this report.

- At McGuire, functional operability of MCCBs was not tested, except for 600 VAC breakers with loads inside the containment. They were not calibrated or tested to verify proper operation of the magnetic and/or thermal trip units inside the breaker, which can be implemented by tripping the breaker open during a fault current.

- At Sequoyah, megger testing of the switchgear was done at a voltage too low to produce meaningful results. The insulation resistance test specified the use of a 500 V megger and an acceptance criterion of 1 megohm. In response to NRC concerns, the utility agreed to use a 2500 V megger and an acceptance criterion of 8.5 megohm, more in line with industry practice.

E.2.2.4 *Post Maintenance Testing*

Positive Aspects

- At Maine Yankee, the program for refurbishment of circuit breakers contained appropriate PMT acceptance criteria for test current and trip time for each trip function (instantaneous, short-time, or long-time delay).

- At Calvert Cliffs, 480 VAC breakers received PMT. Subsystem testing of the breakers was postponed until the system test.

E.2.2.5 *Failure Trending*

Positive Aspects

- At McGuire, the NRC reviewed work requests on 4160 VAC safety-related switchgear. The review showed that since June 1987, there were only 11 work requests, all for minor problems not affecting safety operability. Therefore, repetitive failures of switchgear were not evident.

Negative Aspects

- At H.B. Robinson, PM was performed on all safety related switchgear at each refueling outage. The NRC considered this a conservative interval. However, the NRC's review of 480 VAC safety related switchgear over an 18-month period concluded that there had been five maintenance-related failures. This was a rate of 0.11 failures per breaker-year, which was significantly higher than the IEEE Standard 493-1980[16] rate of 0.0027 failures per unit year. This difference suggested that the maintenance was ineffective.

- At Sequoyah, for the period studied by the NRC, the failure rate of both the 6900 V and 480 V circuit breakers was about five times the industry average, but it was not considered statistically significant, and did not indicate an adverse trend. However, the NRC felt that the system engineers should trend the failure rate to determine the adequacy of maintenance.

- At Cooper, for some systems and plant areas, including components such as MCCs, the Equipment Data File had not been verified, so that not all components and their maintenance histories were included.

E.2.2.6 *Root Cause Analysis*

Negative Aspects

- At Dresden, root cause analysis had not been performed for a subtle trend of problems associated with opening and closing failures of 4160 VAC breakers.

Also, the utility had not adequately evaluated:

(1) The failure of a Unit 2 LPCI Pump D 4160 VAC breaker, resulting from the fact that maintenance had not been performed at the required frequency, had not been identified, and

(2) The failure of a Unit 3 Isolation Condenser Makeup MOV to open.

E.2.3 Motor Operated Valves (MOV)

E.2.3.1 *Specific Aging Insights*

- At LaSalle, the utility was very slow to respond to a 10 CFR 21 notification by Limitorque about common mode failure of melamine torque switches of certain models and serial numbers known to be installed at La Salle. The cause of failure was post- mold shrinkage, which was affected by temperature and age. Specified actions included a review of valve stroke times, conducting stroke time testing, and switch replacements. Five MOVs covered under NRC Bulletin 85-03 and other valves located in a harsh environment had not been inspected for melamine torque switches. Also, thirty Unit 2 valves had not been inspected in response to Generic Letter 88-07.[15] This deficiency was cited as a violation by the NRC.

- Similar problems were noted at Prairie Island where utility had failed to promptly inspect, correct, or justify continued operation of more than 25 Unit 1 and Unit 2 MOVs that were subject to common mode failure of torque switches made of melamine material (as per the November 23, 1988 10 CFR 21 notification by the Limitorque Corp.). The apparent cause of the delays was that the system engineers had too many responsibilities and the assessment was "Low Priority;" this also was cited as a violation by the NRC.

- At Surry, some MOV body-to-bonnet fastener washers in the Safety Injection System were corroded. An engineering evaluation found them acceptable. Many SIS components were wrapped in polyethylene or bagged, either to control small leaks or prevent the spread of radioactive contamination. There was a very thick deposit of an unknown substance covering the packing leak-off drain piping at some SIS MOVs.

- At St. Lucie, following a Unit 2 manual reactor trip, both MOVs for the motor-driven AFW pumps went fully open as intended. One valve was later closed by the operators and the other was throttled to 200 GPM flow rate. The operators later tried to reposition the latter valve but it would not move. Also, the fully closed valve appeared as fully open on the control board. The throttled valve would not respond because the stem and nut were so galled and seized together that it could not be manually positioned. The fully closed valve could not be remotely positioned open because the pinion gear on the limit switch drive had worn to the point that it was not meshed with the drive-sleeve bevel gear. The limit switch was left indicating a "full open" signal to the control room and would only allow the Limitorque motor to rotate in the closing direction.

- At Palisades, there was a large buildup of boric acid on Safety Injection Tank MOVs inside the containment. However, MOVs in the Safeguards Rooms were very clean and the stems were lubricated.

- At South Texas, the Unit 2 Emergency Cooling Water structure was not well maintained. The floors of the pump room were covered with water, exposing components such as local MCCs to high humidity and standing water.

- At Fermi, to verify that the MOVs open fully, the utility had originally planned to open them until an enlarged section of the stem contacted the mating seat in the bonnet, i.e. "power backseating." However, such practices have resulted in broken stems and dropped disks at other plants. Therefore, the utility eliminated power backseating by stopping all valves on the open stroke using the limit switch, rather than the torque switch, so that the power is interrupted before the stem contacts the backseat. In some cases, the stem will coast into the backseat with considerable force. Through a utility-sponsored study by the vendor, the utility concluded that the concern for coast-in backseating is restricted to large, "fast-acting" valves. Lacking evidence to the contrary, the NRC concluded that the practice of coast-in backseating could continue for the remaining MOVs.

E.2.3.2 *Inclusion in a Reliability Centered Maintenance Program*

<u>Positive Aspects</u>

- At San Onofre, the NRC considered the utility to be the leading industry participant in development of a reliability-based PM program, which was an EPRI pilot program for 16 systems. Implementation of an MOV PM program, diagnostic testing programs, and other efforts had significantly reduced MOV failures since 1987. However, little progress had been made in developing a PM program for manual valves used in emergency situations.

- At Millstone 3, the Probabilistic Safety Study had been used to rank MOVs in order of risk significance.

- At Dresden, the NRC noted that MOV diagnostic testing was one example of RCM included in mechanical maintenance.

- At Haddam Neck, the Corporate PRA staff provided a prioritized list of MOVs to be tested in the MOV diagnostic testing program.

<u>Negative Aspects</u>

- At Fitzpatrick, some PM tasks on MOVs had been deferred for more than a year past their due date. However, there had been no deferments of Tech Spec required surveillance, or of EQ-related maintenance.

- At South Texas, the prioritization scheme for MOV maintenance appeared to emphasize the availability of personnel rather than technical justification for PM deferral. Of 275 PM items, at least 28 were "quality" (EQ) MOV PMs, which were to be performed every 78 weeks. The PM included inspection, lubrication and testing. At least eight of the valves were containment isolation valves. The delays in PM ranged from three to 21 months.

  The utility failed to recognize the connection between PM deferrals for MOVs and an increased rate of MOV failure to function upon demand. From 1987 to 1989, 42 MOVs, 34 in Unit 1 and 8 in Unit 2, failed to function. PM had been deferred on at least five of these valves.

E.2.3.3 *Preventive Maintenance Practices*

Positive Aspects

- At Duane Arnold, the MOV maintenance procedures contained information from NRC Bulletins and Information Notices and from plant industry lessons learned.

- At Zion, a new MOV overhaul and diagnostic program for all MOVs had been implemented that included a complete inspection and PM including lubrication of the main gear case, limit switch compartment and valve stem, and proper setting of the torque and limit switches. In 1987, there were 43 MOV failures, but only 26 in 1988, a 40% reduction. All safety and non safety-related MOVs had been added to the PM program.

- At Dresden, an MOV overhaul program had been implemented which included a complete inspection, resistance testing of the motor, lubrication of the main gear case, limit switch compartment and valve stem, and proper setting of the torque and limit switches. Permanently mounted sensors for measuring stem force had been installed on all safety-related environmentally (EQ) and non-environmentally qualified (non-EQ) MOVs. The utility was anticipating better MOV performance and more convenient testing from the VOTES testing method.

  Also, the NRC considered management support of maintenance to be exemplified by the use of teams to perform PM on MOVs to improve reliability.

- At Maine Yankee, condition monitoring of MOVs was part of an ongoing MOV overhaul program which included lubrication, inspection of Limitorque operators, EQ inspection, MOV-ATS testing, torque switch replacement, and changeout of jumper wiring for certain MOVs. A repacking and lubrication schedule for MOVs recently had been started to enhance their performance.

- At Waterford, the scope of the PM program for MOVs included both safety-related and balance-of-plant valves, which the NRC considered to be significantly above the industry norm. The PM requirements conformed to the vendor technical manual recommendations and industry good practice.

- At H.B. Robinson, the Managed Valve Maintenance Program (MVMP) had been implemented to address industry-wide problems with MOVs and check valves to ensure their long-term operability. Existing procedures were being improved, new procedures written, PMT requirements defined, and check valve applications evaluated based on industry experience.

- At Fermi, the procedures for MOV assembly/reassembly and setting of switches were significantly improved, comprehensive, detailed, and easily understood.

Negative Aspects

- At Fort Calhoun, there was an MOV improvement program to identify and correct any valve abnormalities. However, the NRC considered that the program could allow damage to valves and actuators because it permitted higher torque switch settings without any engineering justification.

- At St. Lucie, the utility did not have repair procedures for the motor and turbine-driven AFW pumps and Limitorque MOV actuators. In such cases, repairs had to be made following the vendor's technical manuals. However, PM procedures were in effect for those components.

- At Waterford, three environmentally qualified safety-related MOVs inside the reactor building were lubricated with a mixture of two different types of grease, contrary to the lubrication instructions in the plant manual, which specified only Exxon Nebula P-O.

  High levels of lithium had been found in the gearbox grease of some Safety Injection MOVs inside the containment. The Limitorque technical manual stated that only EXXON Nebula EP-0 and EP-1 were environmentally qualified for such service. Lithium is a constituent of Mobil Mobilux EP-0. The utility concluded that some mixing of the MOV main gear box lubricant had occurred, which could have resulted in actuator failure. Although the utility had already corrected these problems, the NRC noted that weaknesses remained with the other aspects of the MOV lubrication program:

(1) The use of two different types of lubricants for the same component may lead to future mixing of greases for MOVs.
(2) The guidance in the current program was conflicting and did not assure that greases would not be mixed in the future.
(3) Operations QA had not effectively identified that concern.

The NRC cited the above problem as a violation.

- A South Texas, during performance of a PM procedure for "78-Week Inspection, Lubrication and Test of the MOV Actuator for CCW to Charging Pumps Return Valve (MOV)", the NRC noted that the cover gasket of the limit switch/torque switch was totally compressed and hardened. Therefore, the switch compartment of the EQ-classified MOV was not sealed. Also, supplemental holes had been punched in the gasket so it would fit in the existing bolt pattern.

  Also, a procedure for "Limitorque MOV Motor Inspection and Lube" did not refer to staking the motor pinion/motor shaft key and/or set screw. Two requests for field changes dealing with the proper material for the key and key staking had been incorporated into the vendor's technical manual, but not into the procedure.

- At River Bend, during the performance of PM on one MOV, it was noted that the as-found torque switch settings were 1.5 for the open and closed positions. The recommended torque switch settings were 1.75 minimum/2.0 maximum. The procedure allowed the setting to be below the minimum if:

(1) Actual data on valve stem thrust is available that shows the need to lower the torque switch setting, and
(2) Engineering has reviewed the thrust data and approves the lower setting.

  However, there was no documented evidence that the lower setting had been approved.

E.2.3.4 *Incorporation of Vendor Information*

Negative Aspects

- At Surry, the Limitorque Maintenance Update 89-1, dated December 1989, on:

(1) Actuator pinion gear fit-up, orientation, and location,
(2) Gear to shaft key material, fit-up, and retention (staking),
(3) Set screw spot-drilling and retention (lock-wiring/staking) for Limitorque MOV actuators was **not incorporated** into the maintenance procedures nor a controlled document vendor file and vendor manual.

E.2.3.5 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At D.C. Cook, 250 of approximately 500 MOVs in each unit are safety related. A small sample of these MOVs had been tested in accordance with the provisions of NRC Bulletin 85-03. Approximately 100 MOVs, both safety and non-safety related, had been tested using the criteria in Bulletin 85-03.

- At Indian Point 2, trending of valve stroke time via MOVATS was used to initiate PM on MOVs.

- At Indian Point 3, the NRC noted that the utility had MOVATS personnel perform the testing of two SIS hot/cold leg injection stop valves using company information under a procedure for "Testing of Limitorque MOVs Using Motor Operated Valve Analysis and Test System (MOVATS)."

Also, there are approximately 92 safety-related MOVs, of which 72 are EQ equipment. Engineering took colored photographs of many MOV internals during the previous outage, which showed whether the operators had two or four limit switch rotors, an approved torque switch, and correct jumper wires. The photos also could be used to document rework. The MOV work performed during the outage included about 100 PM activities, including PM for the breaker, 16 complete rebuilds, 20 MOVATS, and 60 required operators. The MOV rework was a long-term project to be completed during the next few outages.

- At Zion, measurements of signature current were used to determine the relative condition of MOVs. Stem-thrust diagnostic testing of MOVs, which yields stem thrust by measuring yoke strain through the entire stroke (the VOTES method), was not performed, so the NRC considered the utility to lag behind the industry.

- At Millstone 1, two different MOV testing techniques, MOVATS and VOTES, were being compared on selected MOVs.

- At Vermont Yankee, MOVATS was used for MOV predictive maintenance.

- At ANO, the NRC considered the MOVATS initiative to be significantly greater than the industry norm.

- At Clinton, an MOV reliability and improvement program including MOVATS diagnostic testing had been established. All classes of MOVs were tested to establish base-line data to detect future degradation.

- At Fitzpatrick, the NRC witnessed the preliminary functional test of an RHR isolation MOV using VOTES, and also the baseline test of the RCIC turbine steamline isolation MOV using MOVATS. The functional test of the RHR MOV was conducted without procedures. The valve recently had been overhauled and new baseline test data would be taken according to approved procedures, following the preliminary functional test.

- At Ginna, MOVATS was used in the analysis of valve performance.

- At Haddam Neck, the utility had begun to use the VOTES testing method, which was intended to improve analytical ability and reduce radiation exposure.

  Also, the NRC considered the use of MOV testing for scheduled diagnostic as well as for PMT purposes to be satisfactory.

- At Yankee Rowe, two SIS MOVs were tested using MOVATS. The test procedure incorporated relevant NRC information. The utility had an extensive number of inspections and tests planned for the outage.

- At Prairie Island, the NRC considered only the MOV program among four predictive maintenance programs to be effective.

- At Braidwood, the NRC considered the four predictive maintenance programs, including MOV testing, to be effective and at a level commensurate with the rest of the industry. There was no detailed review of the utility's response to Bulletin 85-03, but a valve test was observed in which diagnostic equipment was used. Valve-specific design basis information, thrust, and torque requirements were obtained from the vendors of the valves and actuators. Setpoint limits were established, and verification was made that the valve thrusts were acceptable.

- At South Texas, in response to NRC Generic Letter 89-10, a program for enhanced inspection and testing of safety-related MOVs was being developed. Approximately 342 Unit 1 and Unit 2 MOVs were identified. Up to 40 valves were to be inspected during the April 1990 outage.

- At Fermi, in response to Bulletin 85-03, diagnostic tests using MOVATS were conducted on all valves identified in the bulletin, and also on valves which frequently indicated problems. Visicorder traces were used on all other valves to obtain baseline data. These traces were made to record limit switch bypass, MOV packing and live loading, actuator tee-drains and grease reliefs, spring pack sizing and preload, and

MOV backseating and leakage after all limit and torque switch adjustments had been made.

- At River Bend, in response to Generic Letter 89-10, a diagnostic testing program was started for MOVs. This was a followup to Bulletin 85-03, which resulted in testing 22 High Pressure Core Spray (HPCS) and Reactor Core Isolation Cooling (RCIC) MOVs.

Negative Aspects

- At River Bend, contrary to the requirements of a maintenance work order for a prompt inspection and retorquing of the yoke and bonnet bolts on an RHR test return MOV, a run-out check with dial indicators to check for a bent stem at the time of stroking was not performed. The NRC cited this as a violation.

- At Duane Arnold, the NRC considered the predictive maintenance to be behind the industry norm. While progress had been made in diagnostic testing of MOVs, MOVATS was not used on safety and non safety-related MOVs not covered by Bulletin 85-03.

  However, VOTES was being implemented for all safety-related MOVs. This was expected to yield better results and more convenient testing.

- At La Salle, MOVATS testing was applied only to those safety-related valves described in NRC Bulletin 85-03. Other safety-related and all non safety-related MOVs were not tested.

  However, a valve testing program which was apparently more comprehensive than the MOVATS program had recently been implemented.

- At Waterford, a limited number of valves were tested under the MOVATS program. Improper torque switch settings had caused overthrusting for some MOV actuators and valve stems. Several defective torque switches were noted. These failures occurred among only the 20 MOVs affected by NRC Bulletin 85-03. These 20 MOVs comprised only 25% of the safety-related valves in the plant. Only eight additional MOVs were tested at the subsequent refueling outage, leaving 65% of the 80 safety-related MOVs untested.

- At Braidwood, there were no problems with the MOV testing program. However, the NRC considered the utility's philosophy to use the vendor-recommended setting to verify valve operability to be the least effective assurance of meeting design function requirements. The desired thrusts calculated by the vendor were less conservative and did not always predict the thrusts required for valve operability against differential pressure. The utility's philosophy was not as conservative as dynamic testing against actual differential pressures.

- The NRC found a similar reliance on vendor-recommended settings at the Fermi plant.

- At South Texas, only about 12 MOVs had been diagnostically tested since computerized MOVATS equipment became available in September 1988.

E.2.3.6 *Post Maintenance Testing*

Positive Aspects

- At Dresden, the PMT requirements such as valve stroking, current limit-switch signatures, and VOTES diagnostic testing were appropriately specified for HPCI MOVs, ADS valves, and MFW components.

- At Maine Yankee, MOVATS testing was used to confirm satisfactory installation of a new torque switch on a HPSI MOV. The closing force was 44,000 lbf. versus the intended setting of 22,000-24,000 lbf. The Limitorque Model SMB-O operator had a recommended maximum thrust value of 24,000 lbf. The valve was disassembled and there were no signs of distortion. Also, the overstress was within the bounds of an analysis made in response to NRC Bulletin 85-03. The root cause was attributed to failure of the maintenance electrician to follow the procedure, i.e. the switch was installed in a preloaded condition instead of having the valve off its back or main seat.

- At Indian Point 2, PMT of the Engineered Safety Feature Actuation System (ESFAS) controls for an MOV was witnessed by the NRC to confirm that rewiring of the valve's manual control switch had not disabled the automatic response capability of the MOV. The test required operators to realign portions of the affected fluid system and to observe the system's response to simulated ESF actuation signals. The NRC inspector reviewed the test approach, observed the test method, and confirmed that the test accomplished the goal.

- At North Anna, after a new torque switch was installed in response to a Limitorque service bulletin, MOVATS was used to test an MOV in the Unit 1 CVCS charging system.

Negative Aspects

- At Vermont Yankee, the PMT requirements were not prescribed in the administrative procedure. The PMT requirements may have been invoked either by maintenance or operations, as necessary, based on work accomplished, e.g. maintenance of safety-related MOVs followed by a generic procedure for valve leak testing or stroke timing. The PMT criteria and processes were not prescribed in the maintenance request procedure.

- At Waterford, there were different PMT requirements for MOV actuators. The requirements for MOVs not previously tested using MOVATS equipment were much less comprehensive than those which had been tested with MOVATS.

- At Calvert Cliffs, a non-conformance report documented that the specified PMT did not adequately assure that two MOV actuators could deliver the torque required for design conditions.

- At Cooper, during repair of an Emergency Condensate Storage Tank Test Line Shutoff Valve, a HPCI MOV, to restore electrical grounds on the 250 VDC bus supply, it was discovered that the insulation on the actuator motor was degraded and required replacement. Because there were neither procedures for actuator repair nor for PMT in the maintenance work request, the PMT applicable to the scope of work was not performed.

E.2.3.7 *Failure Trending*

Positive Aspects

- At Millstone 3, a study of MOV failure rates showed that the negative impact of MOV failures was not significant enough to require changes or modifications in the system.

- At Braidwood, the NRC reviewed the maintenance history for MOVs in selected systems and did not detect any adverse trends or significant failures. From their overall review, the NRC concluded that the MOV maintenance program gave reasonable assurance of satisfactory MOV operation and early detection of significant failure.

Negative Aspects

- At Indian Point 2, the System Engineer program began in 1988 with 12 system engineers plus 2 supervisors. However, some system engineers were responsible for 4 to 7 systems, with major collateral duties such as performing the detailed design of a major modification, or managing a major outage-related task, e.g. MOV work.

- At Sequoyah, based on 1989 NPRDS failure data, several adverse trends were noted involving Limitorque operators and Masoneilan valves. A Condition Adverse to Quality Report had just been prepared that detailed scores of Masoneilan valve failures during the last 9 years. A search across maintenance histories for Main Steam, Main and Auxiliary Feedwater, Chemical and Volume Control, and Safety Injection revealed 284 records of Masoneilan valves with stem rotation problems. (In one case, a SIS flow control valve indicated position as both open and closed). Root cause analysis codes were properly used.

E.2.3.8 *Root Cause Analysis*

Positive Aspects

- At Surry, the Component Failure Evaluation (CFE) Program was set up as a less stringent form of RCA for failures of lesser importance. CFE was automatic for all safety-related component failures, except that MOVs were handled separately.

- At Haddam Neck, a report about incorrect greasing of MOVs was detailed and informative.

- At Fermi, most MOV failures and anomalies, were closely monitored and evaluated for root cause and possible generic implications.

Negative Aspects

- At Hatch, for the failure of an MOV in the HPCI system, a root cause analysis had not been performed. Also, no RCA had been conducted after the failure of the motor for the RCIC steam-supply isolation MOV.

- At Dresden, the utility did not adequately evaluate the failure of a Unit 3 Isolation Condenser Makeup MOV to open.

- At Cooper, the NRC identified four examples in which equipment degradation and/or improper maintenance and modification activities failed to result in a root cause analysis. One of the examples cited was an improper modification of RHR interlock circuits involving an MOV failure.

E.2.4 Check Valves

E.2.4.1 *Specific Aging Insights*

- At D.C. Cook, the total number of check valves at the two units is 440. Ten per unit were examined under the IST program and an additional 23 were examined during each refueling outage. During the 1989 Unit 1 outage, 29 check valves were examined to evaluate the utility's response to industry reports concerning failures of check valves; most were found to be in good condition. However, 4 out of the 29 showed minor pitting, 1 showed signs of erosion and corrosion, and 1 with a centerline split disc had a loose spring, an eroded stem hinge, and a damaged rubber seat insert. All of the valves were restored to operable condition.

- At Palo Verde, there had been redundant trips of the Unit 2 EDG three times on Hi Temp. during the engine cooldown mode, which is a 5-minute unloaded run after operation. The probable cause was a faulty check valve in the air control system of the jacket water high temperature trip instrumentation.

- At Limerick, the full impact of corrosion on SW components was not fully considered, because inspection revealed that 10-20% of ESW check valves had restricted disc travel due to the buildup of corrosion. While these valves were still considered operable, such hidden problems were undesirable.

- At Fort Calhoun, the AFW discharge check valves had a consistent history of external leakage. A visual examination showed loose disc stops and missing stop welds.

- At La Salle, the Unit 2C Condensate Booster Pump had a leaking check valve at a flange connection.

E.2.4.2 *Preventive Maintenance Practices*

Positive Aspects

- At Maine Yankee, the utility replaced an Emergency Feedwater check valve instead of just repairing a leak in the valve body. Also, the work request contained provisions for PMT.

- At Haddam Neck, based on INPO initiatives, an improved maintenance program for check valves had been implemented.

- At H.B. Robinson, the NRC noted that there was a failure to respond promptly to industry concerns about check valves. However, the Managed Valve Maintenance Program had been implemented to address industry-wide issues on MOV and check valves to ensure their long term operability. Existing procedures were being improved, new ones written, PMT requirements defined, and check valve applications being evaluated, based on industry experience.

Negative Aspects

- At Indian Point 2, a 1986 work order to replace a discharge check valve of a Service Water pump that had been scheduled for completion during the current outage was again deferred to a non-outage time. The NRC noted that such repairs are best performed during shutdown.

- At Sequoyah, a Main Steam swing check valve was inspected and showed degradation. Two of the remaining three valves required replacement of parts. Instead, the valves were repaired by weld buildups, and they subsequently failed, apparently due, in large part, to stresses induced by welding.

E.2.4.3 *Predictive Maintenance and Condition Monitoring*

Positive Aspects

- At Salem, check valves from 8 systems from both units had been reviewed by the utility for inclusion into the inspection program, which depended on the type of valve, its function and maintenance history. These factors determined the method and frequency of inspection. About 200 valves were included in the program. The inspection program incorporated guidance from EPRI Project RP-2233-20,[16] application guidelines for check valves in nuclear power plants.

  However, the system engineer expressed doubts about the data obtained from disassembly of the Unit 1 check valves in late 1989, because all valves, regardless of size and type, had been disassembled following a generic procedure.

- At Surry, as discussed in Section E.1.1 of this Appendix, check valves are installed in each of the three steam inlet lines of the common header to the AFW pump turbine. At least one valve per unit was disassembled for inspection at each outage. Testing for leaks was also performed on Instrument Air System check valves which supply air to solenoid-operated valves which, in turn, open the steam admission valves.

- At Limerick, an inspection program for check valves had been established in response to NRC Information Notice 86-01, which would include about 340 valves for both units. Valves will be categorized by service condition, size, type and model, and at least one valve in each group will be sampled.

- At Fort Calhoun, an early-stage program was in place to identify, repair, and prevent incipient failures of check valves.

- At Indian Point 2, reviews were ongoing to determine what additional manual and check valves should be periodically tested. Preliminary results indicated that some check valves not previously tested should be included. This finding may have a significant impact on plant PM requirements, since over 500 check valves were under review.

- At Fitzpatrick, Quality Control personnel videotaped the internals of valves and adjacent piping using state-of-the-art fiber optic equipment during assembly of various Service Water System check valves.

- At Calvert Cliffs, the utility was actively involved in resolving the concerns of industry and the Calvert Cliffs staff about check valves, as identified in NRC Information Notice 86-01. The Nuclear Industry Check (NIC) Valve Group was evaluating techniques for non-intrusive testing check valves. Out of 400 check valves at both units, thirty valves were to be acoustically monitored in 1991. Check valves had been categorized and were being periodically tested for forward and reverse flow, where applicable.

- At Ginna, in response to NRC Information Notice 88-70,[17] 40 check valves had been defined in severe or "other service." A sample valve from each of seven check valve categories is verified for full stroke capability and internal structural soundness during each outage.

- At Haddam Neck, the utility decided to inspect the major Main Feedwater check valves in response to NRC Information Notice 86-01. Other major system check valves had been added.

- At Braidwood, the predictive maintenance program for check valves was at a level commensurate with industry activity and was considered to be effective.

- At Sequoyah, in response to NRC Bulletin 89-02[18] and NRC Generic Letter 87-06[19], on check valves, the check valves of the thermal barrier booster pump in the Essential Raw Water Cooling System were inspected. The internals were degraded by erosion and corrosion. Following an engineering justification to show that these valves were not essential for safe system operation, the internals were removed and the bodies left in place.

- At South Texas, trending forms for leakage tests on the Safety Injection System check valves were used to determine if the leakage was approaching the acceptance limit. If so, possible responses include increasing the frequency of surveillance tests, gathering more data, performing predictive analyses, and performing maintenance or repair.

  The utility identified the check valves and test frequencies based on plant engineering design data. The list included all sizes of safety and non-safety related system check valves, and in steam, water, and gas applications.

- At Fermi, performance monitoring was conducted either by periodic testing, surveillance monitoring, or visual inspection. Data sheets contained information on the valves and their condition, and were routed, with work packages, to trend performance.

- At River Bend, the utility was not trending the results of the check valve monitoring program. However, as noted for Calvert Cliffs, an industry-wide trending program was under development by the Nuclear Industry Check Valve Group. The utility was developing maintenance procedures that would include a data sheet to show positive and negative trends in check valve performance.

  The utility was developing an acoustical emission monitoring (AEM) program as part of the predictive maintenance program for check valves, and was working with EPRI and other utilities to evaluate degraded performance in the laboratory using the AEM program. Any valves identified as degraded or inoperable would be disassembled and inspected during the next outage.

  Also, the NRC reviewed the IST requirements for the Penetration Valve Leakage Control System and the Automatic Depressurization System and found that the check valves were being verified operable as per ASME Code Section XI.

Negative Aspects

- At Fermi, procedural inadequacies resulted in failure to full-stroke test four check valves in the RHR and Core Spray Systems. The test actuator provided only a partial stroke. Full-flow testing of the valves was performed under other procedures. The NRC cited this as a violation.

  Also, the ASME Code Section XI requires that Category C check valves, which perform a safety function in the closed position to prevent reverse flow, be tested in a manner to prove that the disc seats promptly on cessation or reversal of flow. Current testing of the Standby Liquid Control System did not verify closure of the check valve. The utility considered that such testing was beyond the single failure criterion, since failure of both the check valve and a relief valve would be necessary to fail the system. The NRC considered this to be an inadequate response to the utility's own QA findings.

- At Surry, the check valves which ensure operability of backup accumulators for the air-operated valves required for safe shutdown were not included in the IST program.

  Also, as discussed in Section E.1.5.1 of this Appendix, chronic problems had occurred in the EDG Air Start System from leaking check valves.

- At Waterford, the safety-related systems depend solely on the nitrogen stored in the nitrogen accumulators to operate critical valves during an accident. The utility was using a procedure for quarterly ISI valve tests which was intended to meet the requirements of the ASME Code Section XI for 16 individual check valves associated with the safety-related boundary of the nitrogen accumulator subsystems.

The utility was attempting to take credit for determining the operability and capacity of the dump valves for the nitrogen accumulators based on this quarterly test, which had several limitations.

Previous maintenance records, showed that operability of the nitrogen accumulator subsystems had never been verified since startup testing in 1983.

- At H.B. Robinson, three MSIV Instrument Air accumulator check valves, required to maintain the MSIVs in the closed position, were not included in the ASME Code Section XI test program. Functional tests of these valves were performed under another procedure, but only for rapid closure and not for their ability to seat and seal under slow loss of instrument air.

- At H.B. Robinson, the NRC inspected check valves for the Low Head Safety Injection and RHR Systems, Safety Injection Accumulator Outlet lines, the Service Water pump discharge, Main Steam and MSIV Accumulators. The procedures in effect lacked acceptance criteria for the inspection of check valve internals for wear and degradation; also, there was neither a surveillance nor a PM program. Check valves were neither tested nor maintained unless the valve was degraded, or testing/disassembly were required by the ASME Code Section XI. No testing of MSIV accumulator check valves was completed or planned.

- At McGuire, the NRC considered the utility's response to the industry concerns about check valves identified in EPRI NP-5479,[20] dated January 1988, to be adequate, and that appropriate valves were being identified and corrected in the Nuclear Service Water System. However, there were no specific inspection criteria, e.g. dimensions to be measured and recorded, and a failure to compile quantified data on wear and degradation to adjust PM frequency. The utility planned instead upon frequent re-examination of valves showing degradation.

- At Prairie Island, the utility's predictive maintenance program was not at a level commensurate with that of the rest of the industry. Specifically, monitoring of check valves was one of three predictive maintenance programs which the NRC considered to be too insufficiently developed to be of value. There was no definite goal for having these programs fully implemented.

- At River Bend, the testing program for check valves included 102 valves greater than 2.5 in. in diameter, and which failed the design review criteria based on the minimum fluid velocity and proximity to areas of turbulent-induced flow. The minimum velocity for each valve type, as recommended by the EPRI guidelines, was not calculated. Valves less than 2.5 in. diameter were not considered due to their historically low rate of failure.

E.2.4.4 *Post Maintenance Testing*

<u>Positive Aspects</u>

- At Haddam Neck, the NRC inspectors observed PMT of a boration flow path check valve which had been blocked by an accumulation of boric acid. Appropriate PMT requirements were specified, equipment restored to normal configuration, and the PMT was conducted before acceptance for operation.

<u>Negative Aspects</u>

- At Fermi, Operations personnel accepted an RHR check valve without a stroke test following maintenance. The valve subsequently did not stroke and had been incorrectly reassembled. Adequate instructions had not been provided.

This was cited by the NRC as a violation.

E.2.4.5 *Failure Trending*

Positive Aspects

- At Calvert Cliffs, for all check valves, an extensive component history was maintained which was periodically updated and some maintenance was trended.

Negative Aspects

- At Rancho Seco, the method to determine NPRDS reportable failures appeared to contain potential oversights and omissions. There were incomplete or missing entries of failures of Main Steam safety relief valves and Instrument Air System check valves.

- At Haddam Neck, a 6 in. Service Water check valve was disassembled and found to be stuck open. Three similar valves were disassembled, inspected and repaired, but no nonconformance report was written. The NRC felt that the conditions requiring issuance of a non-conformance report should be clarified so that significant deficiencies could be identified, corrected and trended.

- At Sequoyah, the NRC concluded that the utility had a relatively strong check valve program. However, programmatic support and implementation could be strengthened. System walkdowns were neither performed nor documented regularly, and there was no evidence of trending of check valve failures.

E.2.4.6 *Root Cause Analysis*

Negative Aspects

- At Rancho Seco, a nonconformance report was not written when it was determined that debris had caused two Instrument Air System check valves to fail during a special test procedure. The problem had not been recognized for its generic implications, nor for the risks of using sealing tape on threaded joints.

  The NRC cited this a violation.

- At Fitzpatrick, the "Action Accomplished" and "Cause" sections of the work tracking form were not always fully used. In one case, some areas in the work package procedure that asked for specific information were left blank, such as when an adverse condition was found during an inspection of a check valve and the spaces for comment and apparent cause were left blank.

E.7 References

(1) American Society of Mechanical Engineers, ASME Boiler and Pressure Vessel Code, Section XI, Subsections IWP and IWV, Code in effect.

(2) U.S. NRC, "Erosion/Corrosion Induced Pipe Wall Thinning," Generic Letter 89-08, May 2, 1989.

(3) U.S. NRC, "Failure of Main Feedwater Check Valves Causes Loss of Feedwater System Integrity and Water Hammer Damage," Information Notice 86-01, January 6, 1986.

(4) U.S. NRC, "Safety-Related Motor-Operated Valve Testing and Surveillance, 10CFR50.54-(*f*)," Generic Letter 89-10, June 28, 1989.

(5) U.S. NRC, "Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings," IE Bulletin 85-03, November 15, 1985.

(6) U.S. NRC, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," Generic Letter 88-14, August 8, 1988.

(7) U.S. NRC, "Failures of Air-Operated Valves Affecting Safety-Related Systems," Information Notice 88-24, May 13, 1988.

(8) U.S. NRC, "Potential Loss of Motor Control Center and/or Switchboard Function Due to Faulty Tie Bolts," Information Notice 88-11, April 7, 1988.

(9) U.S. NRC, "Inappropriate Application of Commercial Grade Components," Information Notice 87-66, December 31, 1987.

(10) U.S. NRC, "Failure of Westinghouse W-2 Type Circuit Breaker Cell Switches," Information Notice 87-61, December 7, 1987.

(11) U.S. NRC, "Failure of Westinghouse W-2 Type Circuit Breaker Cell Switches," Supplement 1 to Information Notice 87-61, May 31, 1988.

(12) U.S. NRC, "Effect of Circuit Breaker Capacitance on Availability of Emergency Power," Information Notice 88-50, July 18, 1988.

(13) National Electrical Manufacturers Association, "Procedures for Field Inspection and Performance Verification of Molded-Case Circuit Breakers Used in Commercial and Industrial Applications," NEMA Standard AB2-84, (withdrawn).

(14) Institute of Electrical and Electronics Engineers, "Recommended Practice of Design of Reliable Industrial and Commercial Power Systems," IEEE Standard 493-1980.

(15) U.S. NRC, "Modified Enforcement Policy Relating to 10CFR 50.49 Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants," Generic Letter 88-07, April 7, 1988.

(16) Electric Power Research Institute, "Application Guidelines for Check Valves in Nuclear Power Plants," EPRI Project RP-2233-20, Palo Alto, CA, October 1987.

(17) U.S. NRC, "Check Valve Inservice Testing Program Deficiencies," Information Notice 88-70, August 29, 1988.

(18) U.S. NRC, "Stress Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design," Bulletin 89-02, July 19, 1989.

(19) U.S. NRC, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," Generic Letter 87-06, March 13, 1987

(20) Electric Power Research Institute, "Application Guidelines for Check Valves in Nuclear Power Plants," Final Report, EPRI NP-5479, January 1988.

NRC FORM 335 (2-89) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

1. REPORT NUMBER (Assigned by NRC. Add Vol., Supp., Rev., and Addendum Numbers, if any.)

NUREG/CR-5812
BNL NUREG-52309

2. TITLE AND SUBTITLE

Managing Aging in Nuclear Power Plants: Insights from NRC Maintenance Team Inspection Reports

3. DATE REPORT PUBLISHED

MONTH	YEAR
December	1993

4. FIN OR GRANT NUMBER

A 3270

5. AUTHOR(S)

A. Fresco, M. Subudhi, W. Gunther, E. Grove and J. Taylor

6. TYPE OF REPORT

Final

7. PERIOD COVERED (Inclusive Dates)

8. PERFORMING ORGANIZATION – NAME AND ADDRESS (If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)

Engineering & Testing Group
Department of Advanced Technology
Brookhaven National Laboratory
Upton, NY 11973

9. SPONSORING ORGANIZATION – NAME AND ADDRESS (If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission,

Division of Engineering
Office of Nuclear Regulatory Research
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

10. SUPPLEMENTARY NOTES

11. ABSTRACT (200 words or less)

A plant's maintenance program is the principal vehicle through which age-related degradation is managed. From 1988 to 1991, the NRC evaluated the maintenance program of every nuclear power plant in the United States. Forty-four out of a total of 67 of the reports issued on these in-depth team inspections were reviewed for insights into the strengths and weaknesses of the programs as related to the need to understand and manage the effects of aging on nuclear plant systems, structures, and components. Relevant information was extracted from these inspection reports and sorted into several categories, including Specific Aging Insights, Preventive Maintenance, Predictive Maintenance and Condition Monitoring, Post Maintenance Testing, Failure Trending, Root Cause Analysis and Usage of Probabilistic Risk Assessment in the Maintenance Process. Specific examples of inspection and monitoring techniques successfully used by utilities to detect degradation due to aging have been identified.

The information also was sorted according to systems and components, including: Auxiliary Feedwater, Main Feedwater, High Pressure Injection for both BWRs and PWRs, Service Water, Instrument Air, and Emergency Diesel Generator Air Start Systems, and emergency diesel generators, electrical components such as switchgear, breakers, relays, and motor control centers, motor operated valves and check valves. This information was compared to insights gained from the Nuclear Plant Aging Research (NPAR) Program. Attributes of plant maintenance programs where the NRC inspectors felt that improvement was needed to properly address the aging issue also are discussed.

12. KEY WORDS/DESCRIPTORS (List words or phrases that will assist researchers in locating the report.)

Nuclear Power Plants-Aging; Reactor Components-Aging; Reactor Components-Failures; PWR Type Reactors-Maintenance; Reactor Components-Service Life; Risk Assessment; Auxiliary Water Systems, Valves, Electrical Equipment, Feedwater Diesel Engines, US NRC

13. AVAILABILITY STATEMENT

Unlimited

14. SECURITY CLASSIFICATION

(This Page)
Unclassified

(This Report)
Unclassified

15. NUMBER OF PAGES

190

16. PRICE

NRC FORM 335 (2-89)

Printed
on recycled
paper

Federal Recycling Program

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

SPECIAL FOURTH-CLASS RATE
POSTAGE AND FEES PAID
USNRC
PERMIT NO. G-67

120555139531 1 1AN1RV19R
US NRC-OADM
DIV FOIA & PUBLICATIONS SVCS
TPS-PDR-NUREG
P-211
WASHINGTON DC 20555