International Guidelines For Machinery Breakdown Prevention

At Nuclear Power Plants

INTERNATIONAL GUIDELINES FOR

MACHINERY BREAKDOWN PREVENTION AT NUCLEAR POWER PLANTS

PUBLISHED ON BEHALF OF THE

NUCLEAR POOLS' FORUM

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Introductory Note:

These Guidelines have been developed by a Steering Committee representing nuclear insurers in consultation with mechanical and electrical machinery specialists. They have been approved by the undermentioned members of the Nuclear Pools' Forum for use by electric utilities.

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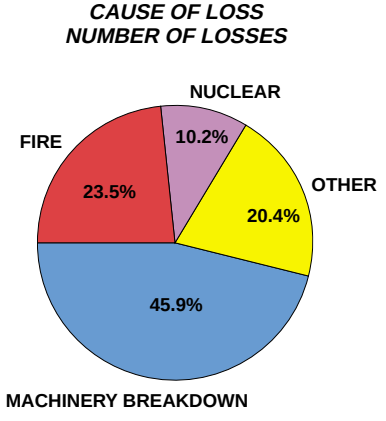
Preface

For over forty years, a specialized "branch" of the world-wide insurance industry, known as the nuclear insurance pools, has written property damage protection for nuclear facilities.

In countries insured through the nuclear insurance pools, an enviable record of operational safety has been attained. Nevertheless, electrical and mechanical equipment does breakdown occasionally. Although these failures do not necessarily compromise nuclear safety, they can cause significant damage to equipment and lead to a considerable loss of generating revenue.

Examples of machinery breakdown events that have occurred in recent years include turbine and generator failures, catastrophic failures of steam, condensate and feedwater piping, foreign material damage in primary and secondary systems affecting both electrical and mechanical systems, and catastrophic failures of transformers, load distribution centers and switchyard equipment. Additionally, machinery failures at power plants can cause major fires.



Of the property damage hazards insured by the nuclear insurance pools, the prevalence of electrical and mechanical machinery failures has led to an increasing demand by utilities for electrical damage, machinery breakdown and all-risk insurance.

Machinery breakdown insurance normally covers mechanical and electrical failures and is one of the most prominent causes of insured loss and one of the more costly. In recent years, losses from machinery breakdown are trending upward as a percentage of the total number of property damage losses.

These Guidelines are organized as a document for the insurance inspector. Each chapter summarizes the expected hazards in a nuclear plant and addresses operational, inspection and maintenance practices observed and proven to reduce insurance risk. For insurance purposes, plants are evaluated against the "best practices" standards, balancing such standards against relevant plant-specific approaches to operation, protection and maintenance.

A particular feature of these Guidelines is recognition of the benefits to both operator and insurer of performance-based maintenance programs over traditional time-based programs. Effective performance-based maintenance can reduce maintenance costs and outage duration. Improved knowledge and understanding of the condition of insured equipment also reduces the insurer's exposure to loss.

The protection and reduction of risk in the operation of pressure vessels and their associated systems is subject, in most countries, to statutory and other regulations where design, construction, operation and inspection are addressed by national codes and standards. As this topic is amply covered elsewhere, it is not discussed in these Guidelines.

In contrast, topics are included that are not generally addressed by nuclear regulatory authorities, whose emphasis is nuclear safety. The nuclear pools have seen, however, that all plant areas containing machinery are vulnerable to machinery breakdown losses. These Guidelines, therefore, should be of essential interest to both insurers and operators.

The Guidelines were developed from the experience of the nuclear pools and incorporate comments provided by nuclear operators. They reflect both broad and specific recommendations known to reduce exposure to potential plant damage. Insurers' application of the Guidelines assists underwriters in evaluating the insurability of an inspected facility and helps minimize insurance loss potential.

In May 1997, the nuclear insurance pools published the third edition of their "***International Guidelines for the Fire Protection of Nuclear Power Plants,"*** which addresses fire hazards at nuclear plants. Now, the ***"International Guidelines for Machinery Breakdown Prevention at Nuclear Power Plants"*** represents a companion volume with a similar purpose and objective.

Chapter 1 – Administration/Operating Programs

1.0 Organization, Qualifications and Responsibilities

1.1 Organization and Management

1.1.1 Machinery breakdown losses can be minimized through the development of quality operating, maintenance and training programs. These programs establish policy for the proper operation and maintenance of structures, systems and machinery, and the qualification and training of personnel.

1.1.2 The plant organization should be described in organizational charts, functional descriptions and position descriptions. Plant policies for programs discussed in these Guidelines should be established in writing and include:

1. The basis for policies
2. Formal endorsement by senior plant and corporate management
3. Assignment of responsibility and authority
4. Program goals
5. Commitment to periodic review of the program's effectiveness

1.1.3 The maintenance organization should include:

1. Program management
2. Engineering and systems support
3. Maintenance tracking and trending capability
4. Mechanical, electrical and I&C (instrumentation and control) maintenance
5. Planning, scheduling and outage management
6. Spare parts management
7. As Low As Reasonably Achievable (ALARA) coordination
8. Training and qualification management

1.1.4 The interface of maintenance with related functional groups should be defined. Related functional groups include:

1. Operations
2. Training
3. Health Physics
4. Quality Assurance/Control

5 Warehouse and Stores
6 Safety Review
7 Engineering

1.1.5 Engineers should be assigned responsibility for all aspects of specific plant systems and components.

1.2 Maintenance Administration

1.2.1 The maintenance program should incorporate a maintenance management system.

1.2.2 A master file of all machinery requiring maintenance should be developed and maintained.

1 The file should identify each piece of machinery, important manufacturer's information and maintenance requirements.
2 All plant equipment should be clearly labeled.

1.2.3 Procedural controls should be established for maintenance activities. A formal process to develop, classify, review, approve, maintain, modify and distribute maintenance procedures should be established.

1 Procedures should be developed, reviewed and formally approved under an interdisciplinary process to assure technical adequacy of related operational, training, safety, engineering, health physics, human factors and quality assurance issues.
2 The process for maintenance procedure development and individual maintenance procedures should be periodically audited by an independent quality assurance function.
3 Manufacturers' manuals, instructions, and drawings used to perform maintenance should be subject to the same level of review and control as internal maintenance procedures.
4 Procedures, manufacturers' manuals, instructions, and drawings used to perform maintenance should be controlled under a controlled document system that ensures the proper distribution and use of documents for maintenance activities.
5 Current information from regulators, insurers, manufacturers and operating experience should be identified and incorporated into the maintenance program.
6 Procedures should be reviewed at no more than two year intervals to assure they are accurate and appropriate.

1.2.4 Maintenance, test, operational and inspection data should be routinely analyzed for the evaluation of system performance and the identification of trends. The result of the analyses should be used to continuously improve the maintenance program and machinery performance. The following should be analyzed to measure and optimize maintenance program performance:

Machinery History

1 Repetitive failures
2 Failures resulting from program deficiencies
3 Mean time between failures
4 Spare parts availability/consumption

Test and Inspection Data

1 Degrading condition identified by trended test data
2 Appropriate test frequency
3 Appropriate maintenance frequency

1.3 Maintenance Activity Control

1.3.1 A process should be developed to control maintenance activities. The process should be defined by procedures that cover the following elements:

1. Initiation
2. Approval
3. Planning
4. Preparation
5. Execution
6. Post maintenance inspection and testing
7. Reporting

1.3.2 ALARA and industrial safety planning for maintenance activities should be conducted.

1.3.3 Manufacturers' and contractors' maintenance activities should be subject to the same administrative, procedural and activity controls as plant maintenance activities.

1.4 Training and Qualification

Plant management and staff should possess the skills, knowledge and abilities commensurate with their individual and collective responsibilities.

1.4.1 A training program should be established to develop and maintain a qualified, trained and skilled staff. The program should be:

1. Developed by qualified personnel, consistent with industry standards and practices and approved by management
2. Managed and implemented by qualified personnel
3. Fully documented
4. Subject to periodic quality assurance audits

1.4.2 The qualification and training program should contain the following elements:

1. Qualification criteria for each discipline and job level
2. Apprentice program
3. Requalification program
4. Continuous training program
5. Formal planning and scheduling of qualification and training activities

6 Documentation of qualification and training for each worker
7 Tracking system to ensure qualifications are current

1.4.3 Job descriptions for each type and level of position should establish requirements for training, qualification and experience needed.

1.4.4 A formal training program for plant and contractor personnel should include classroom and on-the-job training in plant design, systems and administrative controls as applicable to the job description. Training in plant administrative controls should include the following as applicable:

1 Radiation worker training
2 Reading of engineering drawings, schematics and system prints
3 Applicable licensing documents
4 Tagging and locked valve procedures
5 System valve and electrical line-up procedures
6 Work request and permit system
7 Maintenance programs and procedures
8 Surveillance testing programs
9 Quality assurance procedures
10 Health physics procedures
11 Fire protection procedures
12 Security procedures
13 Emergency plan preparedness
14 Foreign material exclusion program
15 Industrial safety procedures

1.4.5 The Training Program should be periodically evaluated to determine effectiveness.

1.4.6 Training facilities should be sufficient to support training programs. Consideration should be given to training on plant equipment mock-ups where possible.

1.4.7 The training program should ensure that radiation training is provided to all plant staff and contractors who will enter into controlled areas to ensure that they will follow recognized ALARA principles and practices.

1.4.8 To independently perform the duties of technician/maintenance person, an individual should possess experience in their speciality, knowledge of the significance and potential impact of their tasks on plant operations and a demonstrated ability to perform assigned tasks.

1 As appropriate, training in the following should be provided:

1 Procedure changes
2 New equipment or significant modifications to plant equipment
3 Plant and industry performance

2 Technician/maintenance persons should be formally qualified and certified by:

1 Written/oral examinations and on-the-job observations to evaluate knowledge and capabilities to perform tasks
2 Remedial training and testing
3 Final certification performed by the individual's supervisor or department manager
4 Periodic refresher training to maintain and enhance personal knowledge and competency

3 Individuals in training or apprentice positions should not be considered qualified for performing work independently. Work performed should be accomplished under the supervision and control of qualified personnel.

1.5 ALARA Program

1.5.1 Maintenance in radiation controlled areas should satisfy all regulatory requirements contributing to the ALARA program.

1.5.2 The radiation exposure to personnel should be monitored, recorded, available for review and should not exceed regulatory prescribed values.

1.5.3 To reduce radiation exposures, the use of remote surveillance and inspection equipment, including closed circuit television (CCTV) and video recording techniques, should be evaluated.

1.6 Chemistry Program

The role of the plant's chemistry program should be to:

1 Minimize the degradation rate of structural materials
2 Reduce the probability of corrosion by controlling key chemical and biological parameters
3 Minimize deposition of corrosion products on heat transfer surfaces

1.6.1 The chemistry program should ensure operation of the nuclear station within the plant's operating license. System and component manufacturers' recommendations should be implemented as appropriate. Sufficient parameters should be monitored to assure timely identification of abnormal conditions or deteriorating trends. Critical process parameters should be identified, and procedures should include:

1 Chemistry control specifications
2 Actions to be taken when monitored parameters are outside the allowed control bands
3 Sampling frequencies, prerequisites, location and sampling methods
4 Chemical additions, impurity removal and operational considerations
5 Reagent preparation, quality control and storage
6 Instrument calibrations and quality control
7 Analytical procedures and measurements
8 Chemical data recording, reporting and trending

1.6.2 Deviations from the chemistry program should require the review and approval of plant management.

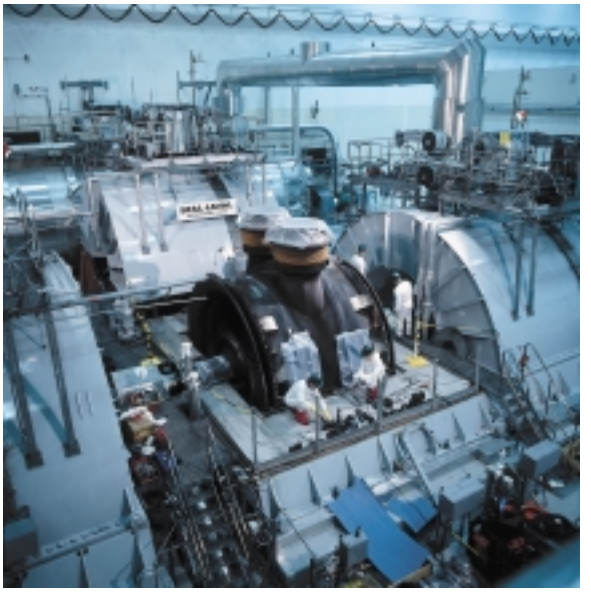
1.6.3 Chemistry data should be promptly recorded and reviewed. Recorded data should support timely interpretation, prompt comparison with acceptance criteria and notification when monitored critical parameters are outside allowable control bands.

1.6.4 A program should be established to trend critical, monitored chemistry parameters with the results reported and reviewed daily by plant management. Consideration should be given to on-line chemistry monitoring for critical process parameters.

1.6.5 A chemistry laboratory quality control program should be established to ensure that specified levels of precision and accuracy are achieved and to provide warning of degrading analytical equipment and human performance.

1.6.6 The storage and use of chemicals should be controlled to prevent improper use or inadvertent introduction into plant systems.

1.7 Foreign Material Exclusion (FME)



Entry of foreign material into plant systems and components is a significant factor contributing to machinery breakdown losses. FME related losses have produced major damage to equipment. Plant recovery can be extremely complicated and expensive because of the extraordinary measures that may need to be employed. Insured losses have frequently resulted from maintenance activities during or at the end of planned outages.

1.7.1 FME program elements should include:

1. Plant policy statement
2. Implementation procedures, departmental directives
3. Work instructions, FME provisions and controls

1.7.2 The FME policy should extend to all maintenance activities at the plant.

1.7.3 FME expectations should be reinforced as part of the maintenance training activities and include:

1. Workers being trained in basic FME practices
2. Information on nuclear industry FME related events
3. Job-specific FME training where appropriate
4. Use of mock-up facilities where available

1.7.4 There should be a high level of supervisory awareness and enforcement of FME standards during pre-job briefings and conduct of maintenance.

1. Supervisors should consistently reinforce FME expectations
2. FME issues should be discussed during pre-job briefings
3. Supervisors should inspect jobs frequently for FME compliance

1.7.5 Work planning and execution should incorporate recognized FME good practices:

1. Establish FME zones
2. Evaluate the work site for potential FME impact including painting, sealing, excavation and operations
3. Conduct inspections prior to starting work
4. Perform post-maintenance system flushes as needed

1.7.6 Physical barriers are an important feature preventing entry of foreign material. They should be subject to:

1. Strict material accountability
2. Engineered for the application
3. Distinctive visibility by color, material or marking
4. Post maintenance inspection

1.7.7 FME deficiencies should be reported and trended under the plant corrective action reporting system:

1. FME problems should be reported
2. Trending and assessment should be conducted
3. Root Cause assessments should be performed for FME events

1.8 Material Handling

A comprehensive material handling control program should apply to all material handling operations, including those conducted by contractors.

1.8.1 Procedures should be written to control how equipment is operated and maintained. Procedures should define and provide guidance for "critical moves" (i.e., operations that have the potential to affect safety or cause other unacceptable consequences). Critical moves should be engineered and planned.

1.8.2 Lifting classifications and their requirements should be defined. Consideration should be given to the characteristics of the load, equipment exposed to damage and the consequence of an accident.

1. Equipment should not be loaded beyond its rated value except for test purposes.
2. Mobile equipment, such as crawler cranes brought on-site by contractors, should be governed by the plant material handling procedures.

1.8.3 Inclement weather, such as high winds and thunderstorms, can cause a substantial increase in the risk of a materials handling loss. Weather-related precautions should be provided in written procedures.

1. Boom cranes should be parked and, if necessary, secured to prevent high wind velocities from causing damage. All crane booms exposed to high winds should be inspected for damage before being returned to service.
2. A weather warning system should be established.
3. Critical lifts should state the minimum acceptable weather conditions. Lifting should not be attempted unless there is sufficient time to complete it prior to the onset of inclement weather.

1.9 Quality Assurance Program

The Quality Assurance (QA) program should contain requirements for how work that may affect equipment operation, maintenance and performance is to be managed, performed and assessed. The program should include organizational structure, functional responsibilities and levels of authority. Quality assurance requirements should be defined in the following areas:

	AREA	EXAMPLE OF PROCEDURES, ACTIONS, RECORDS, ETC.
1	Nonconformance control and corrective actions	Routine inspections and reporting
2	Document control and records	Approval of documents, operating conditions of components
3	Performance indicators	Equipment unavailability
4	Planning	Work request systems
5	Working documents	Repair instructions
6	Housekeeping and cleanliness	Foreign material exclusion
7	Measuring and test equipment	Accuracy and precision
8	Normal, temporary and emergency operating procedures	Startup and shutdown
9	Verification following repair	Run-in following repair
10	Surveillance and testing	Detection of degradation
11	Equipment status and control	Reports on defective equipment
12	Temporary modifications	Documentation and removal of temporary modifications
13	Plant maintenance	Maintenance program and procedures
14	Plant modification and design control	Design change request, construction criteria
15	Condition monitoring	Vibration analysis, temperature monitoring
16	Review of operating experience	Evaluating and feedback of operating events
17	Procurement of services and equipment	Replacement item requirements
18	Handling and storing of equipment	Physical identification of items, preventive maintenance of spares

Chapter 2 – Maintenance Programs

2.0 Maintenance

Maintenance programs generally consist of corrective and preventive maintenance activities and equipment performance monitoring. The plant's work request authorization program should ensure repairs are identified, prioritized and planned, and that parts are available for repair. Maintenance records for components should be maintained to allow for retrieval and trending of component performance. Even the best nuclear power plant will experience component failures and the effects of human performance events. To prevent reoccurrence of failures, plant maintenance programs should have an event reporting process supported by a root cause analysis methodology.

2.1 Corrective Maintenance

Corrective maintenance activities include rework, repair or replacement of equipment or components that have failed or are not performing their intended function. A corrective maintenance program responds to equipment malfunction or failures that require corrective actions. Equipment failure should be documented and reviewed, and corrective actions should be identified.

2.2 Preventive Maintenance (PM)

Preventive maintenance activities are planned, periodic maintenance actions undertaken to maintain equipment within design operating conditions. These actions can be recommended by manufacturers of the equipment/components, based on historic reliability data and corrective maintenance trends.

The following elements of a PM program should be included:

1. Manufacturers' recommendations should be accurately reflected in maintenance procedures. Deviations from these recommendations should be documented and technically sound.
2. Manufacturers' reports on equipment failures and/or servicing should be reviewed.
3. Corrective maintenance experience should be reflected in the program.
4. All protective devices, instruments and controllers should be periodically calibrated and tested.

If the results of PM activities reveal deficiencies, these should be analyzed and corrected before the equipment is returned to service.

2.3 Root Cause Analysis

The root cause of an adverse condition, if eliminated, would prevent its recurrence. Root causes are identified by a formal Root Cause Analysis conducted to determine significant conditions including deteriorating programmatic, human performance, systematic and hardware trends.

1. All causes of significant machinery breakdowns should be identified by Root Cause Analysis.
2. The results of the Root Cause Analysis should be formally factored into maintenance program improvements to identify the causes of repetitive maintenance and appropriate corrective actions.

2.4 Equipment Performance Monitoring (EPM)

Equipment performance monitoring activities are used to measure and diagnose equipment conditions and component degradations. State-of-the-art diagnostic equipment can offer advantages to plant management in optimizing their maintenance programs. Where appropriate, EPM can be used to extend or eliminate time-based maintenance intervals.

1. Equipment performance monitoring priorities should be established.
2. The effectiveness of the Equipment Performance Monitoring Program should be periodically evaluated.

2.4.1 Vibration Monitoring

Vibration monitoring is an element of the EPM program used to identify problems of balance, alignment or bearing condition in plant rotating equipment. The program should:

1. Identify equipment to be monitored, the frequency and location of monitoring and the normal, alert and action ranges of vibration
2. Require increased frequency of monitoring and removal of equipment from service at elevated vibration levels
3. Describe required corrective actions
4. Trend vibration data
5. Review baseline vibration surveys
6. Ensure vibration measuring equipment is calibrated
7. Ensure that engineering:
    1. Assigns normal, alert and action ranges
    2. Recommends test intervals
    3. Designates vibration monitoring location and format
    4. Reviews and concurs with corrective actions for equipment
    5. Reviews vibration trends
    6. Reviews baseline vibration surveys

2.4.2 Lubricant Analysis

The physical condition of lubricants and the equipment they serve should be assessed by a lubricant analysis program.

1. The program should:
   1. Identify equipment to be monitored and monitoring frequency
   2. Trend oil conditions
   3. Evaluate the necessity to replace the oil in a component
   4. Aid in troubleshooting equipment problems
   5. Ensure compliance with lubricant specifications
2. Lubrication sampling requirements, including sample size, frequency, location and acceptance criteria for plant equipment, should be described in plant procedures.
3. Oil samples obtained for laboratory analysis should generally be obtained while the equipment is operating.
4. Ferrography techniques should be used to analyze lubricants for metal wear products and other particulates.
5. Changes in lubrication properties of grease should be monitored. Sensory tests such as color, odor and consistency are most often applied. Analyses should be performed on grease samples obtained from motor-operated valves.

2.4.3 Thermography

Thermography is a measurement of differential infrared radiation patterns to detect changes in equipment condition. It is performed during operation.

1. The plant thermography program should define the equipment to be monitored and the monitoring frequency.
2. Engineering involvement should include:
   1. Review and concurrence of corrective actions for equipment
   2. Periodic reviews of thermograph trends
   3. Reviews of all baseline thermograph surveys
3. Equipment scans should be performed during periods of high operational stress, such as high ambient temperatures, design loads, etc.
4. Semiannual infrared scans should be performed on large transformers, electrical bushings and insulators, breakers and electrical connections.
5. Survey results should be compared with baseline surveys or other accepted industry standards.
6. Abnormal thermography indications should be formally identified and technically evaluated.

2.4.4 Motor Operated Valve Testing

The motor operated valve testing program is used to measure and analyze key motor-operator parameters such as running current, voltage, stem thrust, limit and torque switch set points, and valve stroke times to identify degrading conditions. Program elements should include:

1. All corrective maintenance on motor operated valves should be reviewed. The responsible engineer should be appraised of any abnormal conditions or potential generic problems.
2. Procedures should specify torque and limit switch settings.
3. A data base should be maintained of current torque switch settings and other static and dynamic test data.

4. Baseline data for each motor operated valve should be established and test data trended.
5. Design calculations and dynamic test data should be reviewed to ensure the valves are adequately sized for the particular application. Abnormal test results should be reviewed.
6. Verification of the analytical methods used for functional acceptance of motor operated valves should include a review and analysis of static baseline and dynamic pressure test results for running load, required seating and/or unseating load and differential pressure load, etc.
7. Test results should be used to refine the analytical models and confirm motor operated valve operability at full design basis conditions, such as degraded voltage, that may not have been achieved during baseline and/or pressure testing.
8. Post-maintenance valve testing should be based on the corrective maintenance performed.
9. Maintenance schedules should be based on manufacturers' recommendations, periodic verification requirements and maintenance history.
10. Motor operated valve switch settings should be verified.
11. Postponed or waived preventive maintenance should be reviewed.
12. If testing results indicate that the maximum design thrust or torque limit is exceeded, an engineering evaluation should be performed.

2.4.5 Non-destructive Examination (NDE)

A wide variety of non-destructive test methods are used at nuclear power plants. These guidelines do not describe every method nor provide prescriptive requirements beyond using trained and qualified staff, reviewed and approved procedures, functional certification and calibration of examination equipment.

Test methods include:

Radiography (RT) to evaluate pipe for erosion/corrosion-induced wall thinning and for weld or base material defects.

Ultrasonic (UT) to evaluate erosion/corrosion, cracks, weld defects, bonding defects and wall thickness however, results are very operator-reliant unless computer-driven and interpreted accurately.

Eddy Current (ET) to detect and size defects in non-ferromagnetic tubing in heat exchangers.

Magnetic Particle (MT) to find surface and slightly subsurface defects in ferromagnetic materials using dry, wet or fluorescent particles.

Dye Penetrant (PT) to find surface defects in nonporous materials.

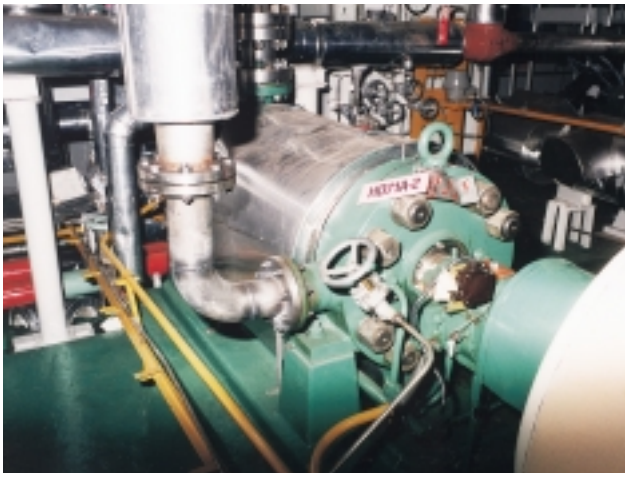
1. The NDE Program should be reviewed and approved by plant management. It should include the qualifications of examiners to perform the various tests and implementation procedures.
2. Quality Assurance management should ensure that NDE program(s) and procedures are developed, approved and administered.
3. Personnel should be trained, qualified and certified for the following functions:
    1. Performance of examinations
    2. Calibration of test equipment

2.4.6 Erosion/Corrosion Monitoring

1. A program should be established to identify and monitor high energy piping and critical equipment susceptible to erosion/corrosion.
2. Component selection for the Erosion/Corrosion Monitoring program should be based on industry experience, analytical modeling and relative ranking from previous examination results.
3. If a component fails to meet acceptance criteria, similar configurations should be checked.
4. If examination results require component replacement, a superior material should be used.

2.5 Surveillance Test Program (Safety Related Systems)

For safety related systems, a surveillance test program that meets the requirements of the operating license should be implemented by plant controlled and approved procedures.



1. Test acceptance criteria should be specifically defined in procedures.
2. Responsibilities for scheduling of surveillance tests, review of surveillance test data and establishing surveillance test acceptance criteria should be assigned.
3. Changes to the plant's operating license should be reflected in appropriate changes to the surveillance test program.
4. Failed surveillance tests should result in the appropriate notifications.

2.6 Surveillance Test Program (Non-Safety Related Systems)

Routine surveillance testing typically includes the testing of automatic pump starts, automatic pressure and flow regulators and other necessary automatic features designed into non-safety related systems. Testing should include verification of the automatic actuation set points and alarms.

2.7 Post-Maintenance Testing

Post-maintenance testing confirms the operability of a component or system and may establish a new performance baseline. Responsibility for test requirements, scheduling and acceptance criteria should be assigned. During unit outages, system configuration may not support such testing, resulting in a backlog of post-maintenance tests to be completed prior to the return to service of systems. A post-maintenance test coordinator should be assigned to determine test requirements, schedule testing and establish acceptance criteria for each test based on the maintenance performed and operability requirements.

1. All testing should be accomplished using approved procedures.
2. Test failures should be tracked.
3. Post-maintenance testing should be completed before returning the system/component to service.

2.8 Maintenance Facilities and Equipment

1. Adequate facilities should be provided for:
    1. Mechanical maintenance
    2. Electrical maintenance

3 I&C maintenance
4 Controlled storage of spare parts and consumables
5 Tool control and storage
6 Controlled storage and calibration of measurement and test equipment

2 Segregated and controlled storage may be required for quality, safety or radiological control purposes.

3 Workshops and other maintenance facilities should be adequate to ensure that maintenance can be performed at all times. The workshops should be segregated into the following areas:

1 Workshops in the controlled zone for regular maintenance on radioactive components
2 Workshops outside the controlled zone for preventive and corrective maintenance.

1 Mechanical workshop equipped for important machining operations
2 Welding workshop
3 Electrical workshop
4 Instrument workshop

2.9 Spare Parts/Material Control

Optimum stock level for spare parts should be maintained. Minimum quantities of individual spare parts should be defined and prompt reordering should be done when this threshold is reached. The limits should be reviewed periodically and adjusted on the basis of experience, outage planning, cost and lead time. A strategic spares program should be in place to prevent prolonged shutdown of the plant. Examples of strategic spares are: turbine and generator components and selected large pumps, motors and transformers.

If spare parts are no longer available or replacement components or suppliers have to be changed for technical or other reasons, an engineering evaluation should be undertaken to determine technical specifications and requirements for alternative spare parts providers.

2.9.1 Spare Parts Handling and Control

1 Spares should be individually identified and controlled to ensure that only correct items are used. Replacement parts and materials should be of at least the same quality as the original parts.

2 Material specification, procurement and issue should be subject to QA audit.

3 Items placed or removed from stores, including surplus material returned, should be documented so that the store's inventory is always accurate. The store's record system should also indicate the location of materials and parts in the warehouse or other designated storage areas.

4 The store's record system should also indicate the date of procurement and items whose shelf-life has expired. In those cases where the shelf-life has expired, the items should be discarded unless an engineering evaluation has approved use of the item.

5 Access to storage areas should be restricted.

2.9.2 Spare Parts Storage

1. Provisions should be made to prevent damage, deterioration or loss of spares and materials. Items should be stored in a manner that provides adequate protection but also allows easy removal. Critical items should be stored according to the manufacturers' recommendations.
2. Large components should normally be stored in the same orientation as when they are in service. This ensures that weight stresses will align in their designed-for orientation.
3. For sensitive items, special coverings or protective environments, such as an inert gas atmosphere or moisture and temperature control, should be provided. Such measures should also be applied to installed items subject to extended out-of-service conditions.
4. Preventive maintenance should be performed on items such as large rotating equipment and motors, including checking of heaters, changing of desiccants, rotating shafts, changing oil or other maintenance requirements as specified by the manufacturer.
5. Storage practices should ensure that:
    1. Corrosive chemicals are well segregated from equipment and metal stock.
    2. Flammables are properly stored in a separate protected area in accordance with the International Guidelines for the Fire Protection of Nuclear Power Plants.
    3. Radioactive material is properly stored, monitored and controlled.
    4. Stainless steel components are protected from halogens and from direct contact with other metals, particularly carbon steel.
    5. Relief valves, motors and other equipment are stored on their bases.
    6. Containers (boxes, barrels, crates) are stacked to reasonable heights and in accordance with manufacturer and storage instructions.
    7. Parts, materials and equipment are repacked or protection restored as required when removed from their original packing.
    8. Elastomers and polypropylene parts are not exposed to light.
    9. Machined surfaces are protected.
    10. Equipment internals are protected from the introduction of foreign materials.
    11. There is suitable segregation of essential and non-essential spares.

2.10 Measuring and Test Equipment

1. Measuring and test equipment should be periodically calibrated as required by plant procedures. These procedures should define:
    1. Responsibilities and qualification of staff
    2. Test procedures
    3. Test frequencies
    4. Acceptance criteria
    5. Test record requirements
2. Measuring and test equipment should be stored according to manufacturer's recommendations.
3. Control and calibration of measurement and test equipment should be specifically assigned and controlled by procedures.

Chapter 3 – Primary Circuit

3.0 General

Implementation of an in-service inspection (IS) program for nuclear plant primary circuit components, systems and support weldments is an important method to minimize equipment failures in the primary circuit. In-service inspections identify conditions, such as flaw indications, that are precursors to failures. These failures can include unacceptable indications that need to be repaired, leaks or structural failures that result in unanticipated plant shutdowns, or catastrophic ruptures that result in plant damage.

3.1 Program Guidelines

The following program guidelines should augment any regulatory mandated in-service inspection requirements:

1. The plant should have a formal primary circuit inspection program that provides for periodic verification of the mechanical integrity of primary circuit components and supports.
2. All weldments and heat affected zones associated with vessels, piping, pumps, valves, heat exchangers, steam separators or generators, core support structures and internals forming part of or connected to the primary cooling circuit should be periodically inspected.
3. Pressure vessel supports and attachment welds should be included in the scope of the primary circuit inspection program.
4. All inspection plans and procedures used in the inspection process should be subject to approval by the regulatory authority.
5. An individual should be assigned responsibility for the inspection program. This individual should have experience in nuclear component design, non-destructive examination and fracture mechanics.
6. The primary circuit inspection program should contain the following major elements:
    1. A clear definition of regulatory or other jurisdictional authority requirements.
    2. An inventory of all safety significant pressure retaining welds by location and safety class.
    3. An inventory of all heat exchanger (including steam generator) tubes and associated welds.
    4. An inventory of all reactor vessel internal welds.
    5. An inventory of all pressure vessel support and attachment welds.
    6. A listing of inspection intervals or frequencies.
    7. A compiled data base cataloguing each weld, the results of inspections, any flaw like indications and any repairs.

3.2 Inspection Preparation

1. Procedures should provide for the necessary preparation and training of all personnel involved with the inspection or maintenance of primary circuit components.

2 Minimum qualification requirements of individuals performing the inspections should be defined.

3 Training and actual inspection of primary circuit components should include strategies that maintain radiation exposures ALARA.

4 Provision should be made for the safe removal, storage and re-installation of all materials that require removal for access to primary circuit components for inspection.

3.3 Inspection Methods

Specific inspection methods should be based on regulatory or other jurisdictional authority requirements.

1 Surface defects may be detected by magnetic particle, dye penetrant or eddy current.

2 Subsurface defects may be detected and characterized by radiography, ultrasonic testing or acoustic monitoring.

3 Hydrostatic pressure testing should be performed periodically based on the recommendations and requirements of jurisdictional authorities and whenever a pressure boundary is breached. The test pressure should be based on jurisdictional requirements.

4 Inspections should be conducted with the latest state-of-the-art equipment and methodologies.

3.4 Inspection Results

1 The inspection program should describe the processes and procedures by which any flaw indications are identified, benchmarked (acceptance criteria) and evaluated.

2 The inspection program should provide guidance for development of repair procedures for flaw indications. When tube plugging is required, the repair procedures should consider relevant industry experience.

3 The repair process should be reviewed and approved by station management.

4 Inspection results should be recorded, retained and subject to the plant's quality assurance process.

5 When component replacement is necessary, original design specifications should be used in the procurement (design, fabrication and testing) of the replacement.

3.5 Equipment Performance Monitoring

During operation, the use of EPM equipment to monitor component and structural integrity should be evaluated. The utilization of CCTV and video recording methods should be considered in addition to diagnostic equipment that has detection and monitoring capabilities. For diagnostic equipment, such as loose parts monitoring systems or acoustic emission systems, consideration should be given to:

1 Correct and efficient location of detectors

2 Calibration and sensitivity of detectors

3 Ability of detectors to function in adverse environmental and radiological areas

Chapter 4 – Main Turbine and Support Systems

4.0 General

Turbine operating hazards are addressed by operational restrictions, protective devices and dismantle/operating inspections. The limited availability of on-line diagnostic monitoring devices results in a significant reliance on dismantle inspections.

4.1 Operating Hazards

The turbine is protected from operating hazards by compliance with operating restrictions and by employing a variety of protective devices. The primary operating hazards are monitored and protection provided by the Turbine Supervisory Instrumentation system (TSI). Operating hazards are evaluated during both operating and dismantle inspections and are described in the following sections.

4.1.1 Overspeed

Overspeed should be prevented by at least two independent protection devices with different set points that actuate to trip the turbine stop and control valves as well as the non-return valves (NRV) in the extraction steam lines. The overspeed protection devices should be testable with the unit in service. Tests should be performed periodically in accordance with manufacturer's recommendations. In case of test failure, corrective actions should be implemented promptly.

4.1.2 Lubrication Failure

Supervision of the turbine to protect against loss of lubrication includes lube oil header pressure monitoring, lube oil temperature monitoring of each bearing drain, bearing metal temperature monitoring and lube oil cooler outlet temperature monitoring. In addition, sight glasses should be installed in the drain lines of each bearing to allow verification of oil flow.

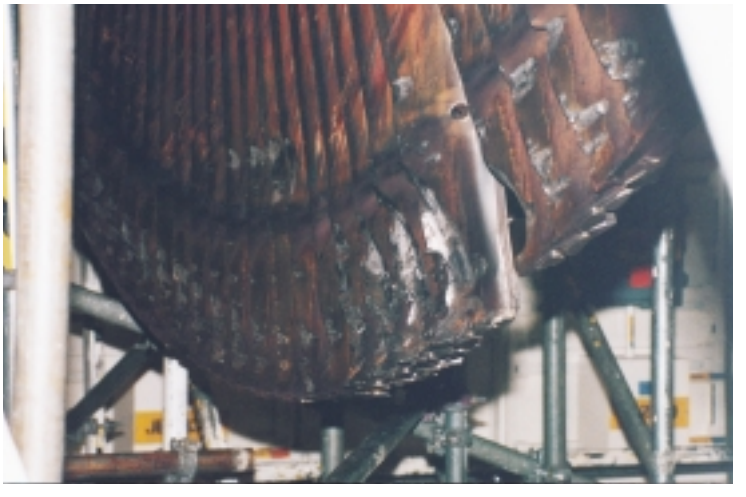
4.1.3 Thrust Bearing Failure

Rotor axial position should be monitored by a system designed to detect small changes in position of the thrust bearing collar relative to the casing. Changes in the thrust collar position will indicate thrust bearing wear, overloading, failure or other conditions causing the rotor to move relative to the casing. Rotor movement relative to stationary components of the machine can result in rubbing damage.

4.1.4 Differential Expansion

Startup, load transients and shutdown of the turbine must be controlled to avoid axial interference between rotating and stationary components during periods when temperature differences between rotor and casing are at the maximum. Differential expansion should be monitored.

4.1.5 Blade and Rotor Failure



Blade and rotor failures are generally due to design deficiencies and/or corrosive attack. Blade failures due to design deficiencies stem from situations where steam flow causes blades to vibrate at a frequency close to a resonance for the blade, resulting in fatigue failure. Corrosive attack on blades or rotors is of lesser concern because of the chemistry and material controls associated with the steam, condensate and feedwater systems. Blade damage may also result from thrust or journal bearing problems that allow the turbine rotor to move axially or radially, causing contact of rotating and stationary components.

4.1.6 High Turbine Exhaust Pressure and Temperature

Turbine exhaust pressure and temperature should be monitored, and the turbine should be unloaded if the exhaust pressure exceeds manufacturer's operating limits. In addition, an automatic turbine trip should be actuated if the exhaust pressure reaches limits that present dangerous operating conditions for the low pressure blades. This condition typically results from a loss of or degraded condenser vacuum.

4.1.7 Stall/Flutter

Main turbine stall/flutter is an unsteady flow condition in which the elastic deformation of a blade couples with its aerodynamic loading to produce a sustained nonsynchronous (not associated with the rotational frequency of the rotor) blade vibration. This is a destructive mode of turbine blade

vibration that is brought about by operating the turbine under conditions of high condenser back pressure. Operating limits for stall/flutter based on manufacturer's recommendations should be established.

4.1.8 High Eccentricity

Eccentricity occurs when rotors are slightly bent due to extended periods of standstill or non-uniform temperature distribution when turning gear operation has been interrupted. Normally such eccentricity will be reduced to acceptable levels when the unit is placed on turning gear. The turbine should not be rolled on steam when values for eccentricity are not within prescribed limits, since bent rotors can result in high vibrations and consequential damage when passing the first critical speed. Eccentricity should be monitored.

4.1.9 High Vibration

High vibration may be an indication of a significant problem and therefore must be rapidly addressed to prevent or mitigate damage. Since the stiffness and damping of the rotor-bearing system is different in the vertical and horizontal directions, the installation of sensors in both directions is recommended. The vibration level of each bearing should be monitored and trended. Operators should be trained in the proper response to indications of high vibration. The automatic high vibration trip should be enabled (operable) to mitigate consequential damages. Turbine high vibration alarm and trip set points should be in accordance with the manufacturer's recommendations. Consideration should be given to setting individual alarm set points for each bearing in accordance with a baseline developed from historical vibration levels.

4.1.10 Torsional Vibration

Torsional vibration can occur where minor electrical grid disturbances cause phase unbalances and unbalanced currents in generators, which ultimately results in double frequency load pulsations on the turbine-generator rotor system. If the natural frequency and vibration mode of the turbine blades is near this double frequency, a sharp resonance resulting in large torsional displacement and high stresses can occur, leading to blade failures. The turbine manufacturer should be consulted to ascertain susceptibility to torsional vibration. Where the turbine manufacturer has recommended inspection and/or torsional testing, these actions should be completed as soon as possible. The most effective corrective action for torsional vibration is to de-tune the turbine-generator unit away from the natural double frequency vibration. This is done by changing the mass and/or stiffness of the rotor system. Calculated resonant frequencies should be sufficiently far from the double grid frequency to demonstrate minimal risk from torsional vibration. Frequency mode shape analysis should be based on contemporary computer codes. This analysis is also obtainable from torsional tests under certain circumstances.

4.1.11 Turbine Water Induction

Water induction to the turbine can result in severe blade damage, distortion of turbine shells, bending of turbine rotors and surface cracks on high temperature components. To prevent turbine water induction, design features are provided in the feedwater heating and drain systems.

4.2 Protective Devices and Trip Logic

1 The protective devices for turbine operating hazards should be functionally tested for operability and calibrated in accordance with manufacturer's recommendations. The following are examples:

1 Low condenser vacuum (local and remote monitoring indication with alarm and automatic turbine trip)
2 Thrust bearing monitoring (remote monitoring indication with alarm and automatic turbine trip)
3 Journal bearing temperature (oil and metal) with remote monitoring indication with alarm
4 Mechanical overspeed (automatic turbine trip)
5 Electrical overspeed (automatic turbine trip)
6 Emergency DC power supply
7 Low lube oil pressure (local and remote indication with alarm and automatic turbine trip)
8 Low lube oil tank level (local indication with remote alarm)
9 High lube oil temperature (cooler outlet) with local and remote indication and alarm
10 Auxiliary lube oil pump run indication
11 Emergency lube oil pump (DC) run indication
12 Control oil pressure high and low indication and alarm, automatic turbine trip on low control oil pressure
13 Low hydraulic control oil (HCO) pressure indication, alarm and automatic turbine trip
14 High/Low HCO temperature alarm
15 Differential expansion (remote monitoring indication with alarm)
16 Turbine shell expansion (remote monitoring indication)
17 Eccentricity (remote monitoring indication with alarm)
18 Bearing/shaft vibration (remote continuous monitoring with alarm and automatic turbine trip)
19 Seal steam high/low pressure indication and alarm
20 Seal steam condenser vacuum indication
21 Seal steam exhaust fan on/off indication
22 High MSR level (local and remote indication with alarm and automatic turbine trip)
23 MSR drain tank level control valve indication
24 MSR outlet steam temperature/pressure indication (local and remote)
25 High turbine exhaust temperature alarm

2 Surveillance testing of trip solenoid valves, condenser vacuum, low bearing oil pressure, thrust bearing (rotor position) and oil pressure test of mechanical overspeed trip should be performed in accordance with manufacturer's recommendations.
3 TSI calibration frequencies should be based on historical reliability data for the equipment installed on the particular unit.
4 Periodic channel checks should be performed for all TSI.
5 Alarm and trip values for TSI should be formalized and provided in alarm response procedures.
6 Lube oil, control oil and HCO lines and connections (transmitters, solenoid operated valves, servos) should be inspected during operator tours for leakage and vibration.
7 Alarm and trip settings should be within specified limits.
8 Any instrumentation and monitoring devices that are out-of-service should be evaluated for their impact on system function.
9 Local turbine instrumentation readings should be compared to control room and other remote instrumentation. Any deviations should be noted and reconciled.
10 Records for vibrations and differential expansions for the last several startups and shutdowns should be reviewed.

4.3 Turbine Operating Inspections

1. Turbines should be operated within the limits specified by the manufacturer (pressures, temperatures, load, vacuum, vibrations, etc.). Any deviations from operating limits or normal operating characteristics should be evaluated for further investigation (subsequent dismantle or special inspections).
2. Turbine performance monitoring should be established to trend variables such as pressures, temperatures, steam chemistry, heat rate and steam/condensate flows where change would predict potential wear, deterioration, leakage and movement.
3. High vibration will occur at critical speeds during startup as well as during shutdowns. Therefore, operation at critical speeds should be minimized. Vibration may also change as bearing lube oil and generator seal oil temperatures change, depending on the position of turbine control valves, condenser vacuum, generator load, generator cooling and bearing alignment and wear.
4. Alarm response procedures for high vibration should include the following:
    1. Alarm and trip set points
    2. Critical speeds and vibration levels to be expected
    3. Verification of main lubricating oil temperatures
    4. Verification of generator load
    5. Actions to be taken on increasing vibration levels, manual trip set points and any other conditions necessary to trip the turbine (duration of vibration, step vs. ramp changes in vibration levels, etc.)
    6. Local and remote verification of elevated vibration conditions
5. Differential expansion of the rotor and casing should be monitored and maintained within manufacturer's specifications to prevent interference between rotating and stationary components. Particular care should be taken during startup and load transients.
6. Thermal strain results from differential heating of turbine components. Main turbine warming temperatures should be monitored during heat up and load transients with deviations evaluated.
7. Bearing oil and metal temperatures should be monitored during turbine operation, particularly during turbine roll.
8. Support systems surveillance data should be periodically reviewed:
    1. Main lube oil system and conditioning (including sampling results/chemistry)
    2. HCO system (including sampling results/chemistry)
    3. Turbine control and protection system
    4. Turbine Supervisory Instrumentation (TSI)
    5. Gland steam system
    6. Exhaust hood spray
    7. Extraction steam including Non-Return Valves (NRV)
    8. Moisture Separator Reheater (MSR)
    9. Lift pump system
    10. Turning gear system
    11. Condenser vacuum and main cooling water systems
9. The availability of DC power to emergency equipment should be verified each shift (batteries and chargers).

4.4 Turbine Dismantle Inspections

4.4.1 Pre-Dismantle

1. Comprehensive reviews of turbine performance should be conducted prior to planned outages. The scope of the review should include:
    1. Instrumentation calibration/overhaul report
    2. Turbine maintenance repair/overhaul report
    3. Nondestructive examination test reports
    4. Technical (manufacturer's) information bulletins and industry experience
    5. Work requests
    6. Surveillance test results for protective systems
    7. Turbine efficiency data
    8. Evaluation of any trends and/or sudden changes in recorded vibration readings
2. Necessary spare parts and consumables should be ordered well in advance of the inspection period in accordance with the required procedures for material procurement. Control of these materials should be part of outage planning.
3. Material handling equipment (cranes, slings, hoists, hooks, etc.) should be functionally tested and meet specifications.
4. The turbine, turbine valves and all auxiliary equipment should be inspected for evidence of steam, oil or water leakage.
5. Shims and casing hold-down bolts should be checked.
6. Piping should be checked for excessive vibration.
7. Piping supports and hangers should be checked for correct position, apparent looseness, broken attachment welds or missing hardware.
8. All turbine valves and safety devices should be tested in accordance with manufacturer's recommendations.

4.4.2 Dismantle Inspections

Turbine dismantle inspections may range from complete dismantling of the turbine to only minor access being required in support of specialized inspections (endoscopic/boroscopic). Turbine dismantle inspection frequency should consider manufacturer's recommendations. There should be a foreign material exclusion program in effect that includes system/equipment closeout following maintenance.

1. Casings should be inspected for evidence of cracking or other distress, erosion, and casing joints for evidence of leakage, erosion or warping. Inspections should include NDE of casings and fasteners.

2 Journals and bearings should be inspected for wear, rubbing, scoring, babbitt unbonding, grooving, wiping, cracks, electrical discharge, discoloration, clearance, etc.

3 Packings and seals should be inspected for evidence of excessive wear and for deformation and clearance.

4 Stationary and rotating blades should be inspected for cracks, looseness, distortion, clearances, corrosion, dents, erosion, foreign object damage, rubbing or broken, cracked or missing shroud bands or lashing wires.

5 Couplings should be inspected for signs of distress, corrosion cracks and alignment. Coupling bolts should be checked for hardness and elongation.

6 Turbines should be inspected for signs of erosion or deposits due to poor steam quality.

7 NDE inspection should be done on blades and blade roots, wheels and steeple areas as required by the manufacturer's programs.

8 Shrink disk LP turbine rotors of some manufacturers are prone to stress corrosion cracking (SCC), a potential problem that could result in a catastrophic disk failure during operation of the unit. NDE inspections should be done on critical areas of these rotors in accordance with the manufacturer's recommendations.

9 In all cases, references should be made to previous examinations of the same item to determine the progress of wear and tear, deterioration, erosion or corrosion.

10 The proper attachment of the bearing pedestals to the bedplate and the tightness of the foundation bolts should be verified. Freedom of movement of the keys as well as of the sliding ability of the thrust bearing should be checked.

11 Casing keys in the guides should be checked for freedom of movement and proper lubrication.

12 Visual inspection of the turbine should be performed to ensure no foreign material remains in the turbine.

4.4.3 Post-Dismantle Inspections

1 The operability of all turbine valves and safety devices should be verified.

2 Trip set points should be verified to be within specified values.

3 When maintenance work invasive to the mechanical overspeed trip mechanism has occurred, an actual overspeed trip test should be performed.

4 Overspeed trip tests should be performed at a minimum of once per refueling cycle. It should be verified by actual overspeed that the overspeed trip functions are within the manufacturer's recommended specifications.

5 A post-dismantle review should be performed and should include:

1 Critical parts that have been replaced or modified with reasons for changes determined.

2 Components scheduled for replacement or repair at future outages.

3 A review of the manufacturer's dismantle inspection results/report including recommendations for future dismantle inspections.

4 An evaluation of which manufacturer's recommendations were implemented and those that were not. Reasons for not implementing recommendations should be reviewed.

5 Manufacturer's technical information communications and status.

6 A review of inventory of spare parts and consumables.

4.5 Turbine Steam and Bypass Valves

These valves are employed during unit startup, operation, shutdown, turbine trip or load rejection. This is a critical function given the level of inertial forces, material stresses and overall energy characteristics of an operating turbine. These are fast-acting valves with hydraulic actuators required for opening against heavy spring force and/or steam pressure. Since these valves operate in a high

temperature and pressure environment, valve wear and fatigue is expected under normal operating conditions. Therefore, periodic routine maintenance and surveillance must be performed to ensure reliable operation.

4.5.1 Operational Inspections

1. The turbine stop (throttle), control (governor), intercept and reheat stop valves should be tested periodically in accordance with the manufacturer's recommendations.
2. The proper operation of accessible valves should be observed by operators locally at the turbine and in the control room. Sufficient remote indication (valve position, steam flows) should be available to verify valve stroke.
3. Valve functional testing should be controlled by procedure, and all manufacturer's recommendations should be observed.
4. Electrical test circuit interlocks should be periodically tested either during operation or shutdown.
5. Valve position indication instrumentation should be periodically calibrated.
6. Leak-off lines and gland steam extraction lines should be periodically checked for evidence of excessive leakage. Any isolation valves associated with these lines should be verified in the proper position for operation.
7. Associated piping supports and hangers should be periodically inspected for correct position, missing hardware, cracked welds and other signs of distress.

4.5.2 Outage Inspection

1. All valves should be inspected to the manufacturer's recommendations and should consider the specific function, service and results from previous inspections.
2. Inlet steam strainer baskets should be inspected during dismantle.
3. Valve inspection and maintenance should include hydraulic actuator units, including pistons, housings, fittings and seals. Inspection and maintenance activity should not introduce contaminants into the HCO fluid. Maintenance requiring further dismantlement should be conducted as necessary.
4. Valve linkages should be inspected for signs of damage.
5. Valve tolerances should be verified.
6. Valve operability tests should be conducted after prolonged periods of non-use, such as shutdowns, and after any physical inspection, maintenance activity, modification or replacement.
7. Valve operability tests should be performed following any significant thermal transient.
8. Bypass valve and HCO accumulators should be tested to ensure operability.

4.6 Lube Oil Inspections

1. Pumps should be disassembled, inspected, refurbished as necessary, tested and returned to service as recommended by the manufacturer.
2. Pump and motor vibrations and alignment should be monitored as necessary.
3. Lube oil coolers should be inspected and cleaned according to the manufacturer's recommendations.
4. Lube oil cooler tube integrity should be verified periodically.
5. Screens, meshes and filters should be inspected.
6. All instrumentation (pressure switches, flow switches, etc.) with automatic start and trip functions should be inspected, calibrated and tested in accordance with the manufacturer's recommendations.

7 Lube oil cooler temperature control valves should be inspected and functionally calibrated.

8 Differential pressure switches, transmitters or indicators associated with screens and filters in the lube oil system should be periodically inspected, calibrated and tested.

9 Instruments for level and temperature indication and alarms on the lube oil reservoir and lube oil storage tanks should be periodically inspected, calibrated and tested.

10 Main control room and local control panel alarm lights should be tested each shift to ensure operability. The initiating devices for these alarms should be periodically inspected, calibrated and tested.

11 The auto start features of the various lube oil system pumps should be tested. Automatic start indication and alarm functions should be monitored in the main control room.

12 Lube oil inlet and outlet temperatures and storage tank and reservoir levels should be recorded by operators as part of their rounds and trends should be noted.

13 Lube oil header pressure should be recorded by operators as part of their rounds, and deviations should be noted.

14 Lube oil should be sampled periodically to determine compliance with manufacturer's recommended parameters. Oil that does not meet specifications should be replaced or reconditioned.

15 Drains associated with the lube oil system should be equipped with threaded caps.

4.7 Bearing Inspections

1 Bearing oil inlet and outlet temperatures should be monitored and recorded by operators and results should be trended.

2 Bearing babbitt temperatures should not exceed values recommended by manufacturers. Temperature alarm settings should be set according to operating experience.

3 Bearing vibration should be continuously monitored and trended.

4 Thrust Bearing Wear Detector (TBWD) should be tested and calibrated. The readings should be logged and trended for indications of abnormal wear or thrust bearing loading.

5 Turbine trip functions associated with the TBWD devices should be operable.

6 Following bearing reassembly, the bearing oil inlet pressure should be checked and compared with historical data.

4.8 Turning Gear

1 The turning gear should be manually turned before engagement to ensure that the turbine-generator rotors are free from obstruction.

2 The turning gear linkage should be inspected for evidence of cracking and excessive wear.

3 Solenoid valves should be functionally tested on a routine basis.

4 Turning gear and oil lift pump pressure switches, indicating devices and alarms should be calibrated and functionally tested on a routine basis.

5 Oil lift pump filters should be cleaned periodically.

6 Actual shaft lift at each bearing should be checked, recorded and trended.

7 Oil lift pump pressures should be monitored locally (if available).

8 Lift oil pressures should be compared with historical data.

9 When the turbine-generator is on turning gear, it should be inspected. Audible noise can indicate possible internal damage.

10 The power consumption of the turning gear motor should be trended.

11 The turning gear should be dismantled periodically according to the manufacturer's recommendations.

12 The automatic turning gear should be functionally tested at each outage.

4.9 Hydraulic Control Oil (HCO) Inspections

1. The following should be checked daily:
    1. HCO system for leaks
    2. Filter status and differential pressures
    3. HCO pump suction strainers
    4. Differential pressure of back-up filter
    5. Accumulator pressure (if local instrumentation is installed). If no instrumentation is provided, the pressure should be tested and verified to be within manufacturer's recommendations.
2. The following should be done as recommended by the manufacturer:
    1. Air dryer desiccant check (if applicable).
    2. Standby HCO pump test (auto start feature).
    3. Test of a representative sample of HCO fluid against manufacturer's recommended values. Test for:
        1. Specific gravity
        2. Water content
        3. Chlorine content
        4. Particle count
        5. Neutralization number (resistivity)
3. The following should be done periodically:
    1. Clean HCO pump suction strainer.
    2. Change HCO filters and HCO backup filters when maximum recommended pressure drop is reached.
    3. Change filter elements as recommended by manufacturer.
    4. Reactivate air dryer alumina when saturated with water.
    5. Check and trend motor current of HCO pumps.
4. The following should be done periodically during refueling outages:
    1. Ensure that replacement filters, gaskets, and seals are compatible with HCO fluid.
    2. Calibration of HCO instrumentation.
    3. Maintenance/testing of solenoid valves (The valves should be included in the plant's PM program).
    4. Refurbish or replace the overspeed and emergency trip solenoid valves.
    5. Clean, inspect and perform NDE or vacuum/pressure tests of HCO coolers.
    6. The HCO system should be flushed and cleaned as recommended by the manufacturer.
    7. Lubricate HCO pump motors and couplings.
    8. Refurbish or replace HCO pumps on a regular frequency as recommended by the manufacturer.

4.10 Extraction Steam and Drains

4.10.1 Operations

1 Turbine and extraction line drain valves should be power operated. These valves should be set to open automatically on a turbine trip and be remotely operated from the control room.

2 Extraction line drain valves should open automatically on high-high level in the associated heater.

3 The mechanical and electrical operation of power operated drain valves should be tested according to manufacturer's recommendations. This test may be accomplished by operating the valves from the control panels and observing indicating lights. Actual valve stroke/position verification should also be conducted.

4 An operational test of the extraction steam line power operated non-return check valves (including all solenoid valves, air supply, etc.) should be performed according to manufacturer's recommendations. This test should also verify actuation of the associated extraction line drain valves.

5 Alarm Response Procedures (ARPs) should identify actions to be taken on receipt of a condensate or feedwater heater high level alarm.

6 Upon a turbine trip, the operator should ensure that all power operated non-return check valves close.

7 If any condensate/feedwater heaters automatically isolate, the extraction steam should be isolated to out-of-service condensate/feedwater heaters, and turbine load should be adjusted in accordance with manufacturer's recommendations.

4.10.2 Maintenance

1 The heater level control valves (normal and alternate) should be subject to periodic loop calibrations. Level control loop calibrations should include the level transmitter, level controller and valve positioner (including valve stroke verification).

2 The corrective maintenance/failure history of the heater level control valves and emergency dump valves (to the condenser) should be reviewed periodically. The results of this review should be used to determine preventive maintenance requirements/schedules.

3 The control logic for any extraction steam line automatic shutoff valve and any drain valve should be periodically tested. This test should include the complete control loop, including valve actuation/position, and should verify actuation of the associated extraction line drain valve.

4 Heater level switches, including alarm verifications, should be periodically calibrated.

5 Periodic preventive maintenance should be performed on the power operated non-return check valve.

6 The extraction steam lines should be periodically inspected for erosion/corrosion damage.

4.11 Moisture Separator Reheaters

4.11.1 Operations

1. An operational test of the power operated non-return check valves (including solenoid valves, air supply, etc.) should be performed according to manufacturer's recommendations.
2. Upon a turbine trip, procedures should call for the operator to ensure that all power operated non-return check valves are closed.
3. Positive isolation of the tube bundles from heating steam must be assured until the turbine generator reaches the specified load for reheater activation.
4. Controlled admission of heating steam to the tube bundle is required in order to avoid excessive thermal shock.
5. MSR-to-MSR differential temperature should not exceed the temperatures recommended by the turbine manufacturer. Operating procedures should require verification of MSR temperatures prior to turbine roll and during staged heatup.
6. Alarm Response Procedures (ARPs) should identify trip functions and actions to be taken on receipt of an MSR drain system high level alarm.
7. ARPs should identify actions to be taken upon a reheater tube leak detection alarm/ identification.
8. Upon a turbine trip, the operator should ensure that the reheat steam supply isolates.
9. MSR thermal performance should be routinely monitored, trended and evaluated.
10. Reheat steam flow and/or differential pressure should be routinely monitored, trended and evaluated for leak detection purposes.
11. Reheater outlet temperature should be routinely monitored, trended and evaluated.

4.11.2 Maintenance

1. MSR drain tanks level control valves (normal and alternate) should be subject to periodic loop calibrations. Level control valve loop calibrations should include transmitter, level controller and valve positioner (including valve stroke verifications).
2. The corrective maintenance/failure history of the MSR drain tank level control valves should be reviewed periodically. The results of this review should be used to determine preventive maintenance requirements/schedules.
3. MSR drain tank level switches, including alarm verifications, should be periodically calibrated.
4. MSR high level turbine trip logic should be periodically calibrated.
5. Periodic preventive maintenance should be performed on the power operated non-return check valves located in the extraction lines to the MSRs.
6. Reheat steam loading valves should be subject to periodic loop calibration.
7. Heater tubes should be tested for integrity.

4.11.3 Dismantle Inspection

A dismantle inspection should be performed on each MSR as recommended by the manufacturer. The following should be considered.

1. Manways and covers should be cleaned and inspected for erosion.
2. U-bends and supports should be inspected for alignment, bowing and interference.
3. Impingement baffle, tube bundle headers, pass partitions, vessel internal structures and inlet/ outlet nozzles should be inspected for erosion, corrosion and cracking.
4. First and second stage reheater tubes should be tested (vacuum, pressure or eddy current).

5 A random sample of the outlet header tube-to-tubesheet welds of both stages should be dye penetrant/magnetic particle tested. Should indications be found, the sample size should be expanded.

6 Moisture separator drain tanks and reheater drain tanks should be subject to periodic visual inspection and cleaning.

7 The vessel and welds should be NDE tested as recommended by the manufacturer.

8 A material control program should be established to ensure that foreign materials are not left in the MSR, associated drain tanks or interconnected piping.

4.12 Steam Seal Inspections

1 All indications, controls and protective devices should be monitored, functionally tested and maintained in accordance with the manufacturer's guidelines. Deviations should be technically justified.

2 Shaft seals should be inspected periodically; springs that hold the packing rings in place should be checked for cracks and proper function.

4.13 Exhaust Hood Spray

4.13.1 Operation

Alarm Response Procedures (ARPs) should identify actions to be taken upon an Exhaust Hood high temperature alarm.

4.13.2 Maintenance

1 The temperature control valve, including the temperature sensor, should be loop calibrated on a regular frequency.

2 Calibration of the high exhaust hood temperature indication, including corresponding alarms, should be performed on a regular frequency.

Chapter 5 – Secondary Circuit

5.0 General

The secondary circuit consists of the condensate and feedwater heaters, main condensers and miscellaneous heat exchangers.

5.1 Condensate and Feedwater Heaters

5.1.1 Operations

1. Controlled admission of heating steam to the tube bundle is required in order to avoid excessive thermal shock.
2. Alarm Response Procedures (ARPs) should identify trip functions and actions to be taken upon a heater high level alarm.
3. ARPs should identify actions to be taken if a heater tube leak is identified.
4. Thermal performance of each heater should be monitored and trended.

5.1.2 Maintenance

A dismantle inspection should be performed on each heater as recommended by the manufacturer. The following should be considered.

1. Heater tubes should be visually inspected for erosion/corrosion and other damage.
2. U-bends and supports should be inspected for alignment, bowing and interference.
3. Impingement baffle, tube bundle headers, pass partitions, vessel internal structures and inlet/outlet nozzles should be inspected for erosion, corrosion and cracking.
4. Heater tubes and tube-to-tubesheet welds should be tested for integrity.
5. Heater drain tanks should be subject to periodic visual inspection and cleaning.
6. Covers should be cleaned and inspected for erosion.
7. The vessel and welds should be NDE tested as recommended by the manufacturer.

5.2 Main Condenser

5.2.1 Operations

1. Condensate conductivity should be continuously monitored at several locations in the condensate/feedwater cycle. Increased conductivity should activate an alarm in the main control room. If conductivity exceeds a prescribed level, the turbine should be tripped.
2. Thermal performance of the condensers should be monitored and trended.

5.2.2 Maintenance

1. Cleaning and inspection should be based upon manufacturer's recommendations and operating experience.
2. Condenser tubes should be visually inspected for erosion/corrosion and other damage.
3. Impingement baffle, tube bundle supports, pass partitions, internal structures and inlet/outlet nozzles should be inspected for erosion, corrosion and cracking.
4. A random sample of the tubes should be tested for integrity. If abnormalities are found, the sample size should be expanded.
5. Corrosion protection (epoxy and/or rubber coating) should be visually inspected for defects.
6. Cathodic protection should be inspected and replaced as necessary.

5.3 Miscellaneous Heat Exchanger Maintenance

The frequency for inspections of heat exchangers depends on the cooling medium, tube material, operating experience and importance of the heat exchanger. The following should be considered:

1. The tubes of the heat exchanger should be visually inspected for erosion/corrosion and other damage.
2. Depending on the size of the heat exchanger, the entire heat exchanger or only a random sample of the tubes should be integrity tested. If abnormalities are found, the sample size should be expanded.
3. Tube bundle supports, pass partitions, internal structures and inlet/outlet nozzles should be inspected for erosion, corrosion and cracking.
4. Corrosion protection (epoxy and/or rubber coating) should be visually inspected for defects.
5. Cathodic protection should be inspected and replaced as necessary.

Chapter 6 – Large Pumps

6.0 General

Large pumps in these guidelines generally refers to high monetary value pumps or pumps with nuclear safety significance, including:

1. Primary heat transport pumps
2. Reactor/steam generator feedwater pumps
3. Main condenser cooling water pumps (main circulating water pumps)
4. Heater drain transport pumps
5. Condensate transfer pumps
6. Nuclear safety related pumps

6.1 Operation

A test program should be developed to ensure that centrifugal pumps operate as close as possible to the pump curve supplied by the manufacturer. Manufacturer's recommendations should be closely followed for allowable pump performance characteristics.

6.2 Operating Hazards

Operating and maintenance programs should be developed to respond to the following pump operating hazards:

1. Cavitation
2. Wear of impeller sealing rings
3. Bearing wear
4. Gland leakage or mechanical seal leakage
5. Shaft bending or warping
6. Impeller wear or damage

Most premature pump shutdowns are related to seal and bearing failures. Seal failure is usually caused by:

1. Incorrect installation: refer carefully to the manufacturer's recommendations
2. Overheating: perhaps loss of cooling or flushing water
3. Change of state of pumped fluid - e.g., from a liquid to a vapor

Bearing failure may be caused by:

1. Incorrect installation: refer carefully to the manufacturer's recommendations
2. Loss of lubricant
3. Contamination of lubricant

4 Excessive lubrication - e.g., too much grease or oil
5 Overheating: loss of secondary cooling, vibration, misalignment, radial or axial thrust

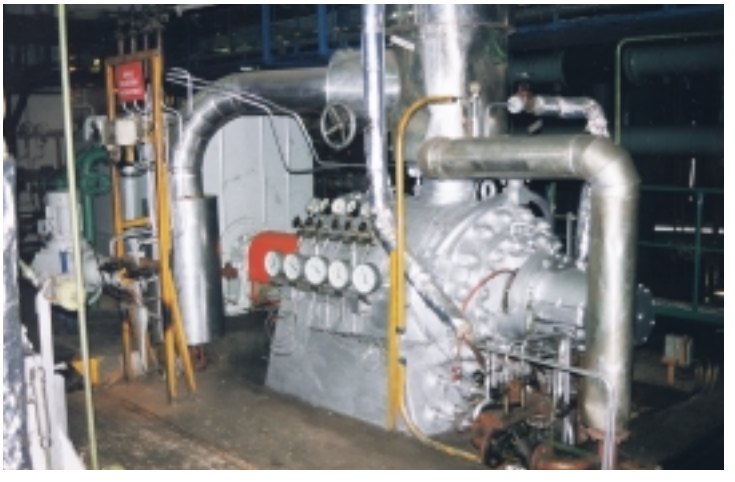
6.3 Operating Inspections

Operating personnel should be present at the pump during startup, if conditions permit. The following conditions should be checked as applicable:

1 Vibration
2 Unusual noise levels
3 Overheating
4 Seal leakage
5 Suction and discharge pressures
6 Oil levels/temperature/pressure/flow/filter status
7 Seal water temperature/pressure/flow

6.4 Equipment Performance Monitoring

1 On-line monitoring should be installed on large primary and secondary circuit pumps, depending on importance and ease of accessibility. Parameters monitored should follow the manufacturer's recommendations. The following should be considered:



1 Suction and discharge temperatures
2 Suction and discharge pressures
3 Internal clearance between impeller and volute
4 Shaft deflection
5 Shaft axial movement
6 Vibration
7 Flow rates
8 Bearing temperatures
9 Bearing oil temperature
10 Bearing oil pressure
11 Shaft speed
12 Stuffing box or mechanical seal condition

2 On-line monitoring may be used for alarm annunciation only or, depending on importance, alarm annunciation followed by pump shutdown. All readings should be recorded and trended.

1 Baseline values should be established as soon as possible for newly installed pumps.
2 Regular recorded vibration and lubricant analysis should be performed on all large pumps.

Chapter 7 – Safety Devices for Overpressure Protection

7.0 General

Safety devices for overpressure protection (devices) include:

1. Safety Valves
2. Relief Valves
3. Safety Relief Valves
4. Rupture Disk Devices

A written procedure should be established for procurement, installation, inspection, test, maintenance and repair of all safety devices for overpressure protection.

7.1 Definitions*

1. Safety Valve - An automatic pressure relieving device actuated by the static pressure upstream of the valve and characterized by full opening pop action. It is used for gas or vapor service.
2. Relief Valve - An automatic pressure relieving device, actuated by the static pressure upstream of the valve, that opens further with the increase in pressure over the opening pressure. It is used primarily for liquid service.
3. Safety Relief Valve - An automatic pressure-actuated relieving device suitable for use either as a safety valve or relief valve, depending on application.
4. Rupture Disk Device - A non-reclosing pressure relief device actuated by inlet static pressure and designed to function by the bursting of a pressure retaining disk.

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7.2 Deadweight Safety Valves

Deadweight (weight and lever) safety valves should not be used.

7.3 Installation

1. Devices should be installed in conformance with the manufacturer's instructions and meet jurisdictional requirements where appropriate.
2. Safety Valves and Safety Relief Valves installed on boilers or pressure vessels should be installed in the upright position with the valve spindles vertical.
3. There should be no intervening block or isolating valves between the pressure source and the device unless this is specifically allowed for by the jurisdictional authority. There should be no intervening block or isolating valve between the device and the atmosphere.
4. Where rupture disks or a combination of rupture disks and re-closing devices are installed, it should be verified that jurisdictional requirements are met.
5. Where rupture disk devices are installed on a valve outlet, the intervening space must be equipped with a pressure gauge, a try-cock or tell-tale indicator to indicate signs of leakage past the valve.

6. Drainage device(s) should be connected to the discharge pipe.
7. Verify that safety valves are installed in the upright position.
8. Verify that inlet piping and discharge piping is not smaller than the device inlet and outlet size, respectively.
9. Verify that there are no intervening valves between the device and the pressure source unless specific jurisdictional requirements are met.

7.4 Operating Hazards

A number of operating hazards may exist. Operating and maintenance procedures should address these hazards, as appropriate:

1. Discharge of high pressure/high temperature fluids
2. Reaction damage due to inadequately supported discharge pipes
3. Valve body deformation due to inadequately supported discharge pipes, reaction or expansion loads
4. Blockage of discharge pipes by water, ice or debris
5. Build-up of foreign deposits on valves
6. Corrosive attack on the seating surfaces of the valves, resulting in adhesive film
7. Valve drainage pipes or orifices blocked
8. Unauthorized lift pressure or blowdown setting adjustment
9. Build-up of vessel content deposits on disks
10. Corrosion of disk, causing rupture below designed pressure setting
11. Fatigue or creep, causing rupture below designed pressure setting

7.5 Operating Inspections

The following operating inspections should be performed:

1. Examine devices for signs of leakage or, where devices are not accessible, verify by examining operating parameters, e.g., tailpipe temperature readings.
2. Where possible, visually ensure that all drainage pipes and orifices are free and clear.
3. Where possible, confirm that seals are intact and show no evidence of tampering.
4. Actuation of any safety device should be logged, and a root cause analysis should be performed for any unplanned actuation.

7.6 Preventive Maintenance

Preventive Maintenance procedures should conform to the manufacturer's recommendations. The following should be considered:

1. Regular manual testing at periods prescribed by the manufacturer and/or the jurisdictional authority, modified by operating experience. Manual testing should not be attempted when the steam pressure is less than 75% of the set pressure of the lowest set valve.
2. Manufacturer and/or jurisdictional advice should be sought before employing "lift assist" devices for on-line testing of safety valves.
3. Regular check of all discharge pipe support arrangements.
4. Regular check to ensure that valve is not gagged.
5. Regular check of intact seals on spring and blowdown setting adjustment points.
6. Verify that all drainage pipes and orifices are free and clear.
7. Periodic removal, refitting and re-setting of all safety and pressure relief valves, as prescribed by the manufacturer and/or the jurisdictional authority.

8 This work should be undertaken only by an authorized valve repair shop working to a stringent, independently audited, quality assurance program. Adjustment setting seals should be applied only by the valve repair shop or their authorized representative. Safety Valve tests should establish the set (opening) pressure and the closing pressure of the valve.

9 Individual testing and maintenance records should be kept for each valve.

7.7 Dismantle Inspections

Component dismantle inspections should be conducted in accordance with manufacturers' recommendations and the jurisdictional authorities' requirements.

Chapter 8 – Main Electrical Generator and Support Systems

8.0 General

Three major inspection types are addressed in this chapter; operating, dismantle and robotic. Operating inspections are enhanced when diagnostic equipment is used. The use of on-line diagnostic equipment represents a significant maintenance tool. This does not diminish the importance of installed mechanical and electrical protective devices, instrumentation, alarms and routine operational surveillance. Together, these features of a properly protected generator contribute to component reliability, reduced maintenance costs and minimized insurance risk.

8.1 Operating Hazards

The generator is protected from electrical hazards by compliance with operating restrictions and by employing a variety of relaying schemes. Mechanical hazards are addressed during operating, dismantle and robotic inspections and, in some cases, by diagnostic monitoring equipment.

8.1.1 Electrical Hazards

Most generator electrical hazards (transients and faults) cause sudden increases in stator currents, with subsequent excessive temperature. Also common to these hazards are severe mechanical shocks caused by increased mechanical (magnetic) forces that could cause damage to end turns, blocking, winding insulation and possible shocks to the turbine-generator coupling and shaft.

8.1.1.1 Stator Overheating

Stator overheating is caused by overload, cooling system failure, or short-circuiting. Overheating will deteriorate insulation and lead to faulting.

8.1.1.2 Stator Ground Faults

Stator ground faults are caused by the deterioration of stator winding insulation, either by aging, overheating or mechanical deterioration, such as insulation migration or stator bar vibration.

8.1.1.3 Stator Phase-to-Phase Faults

Faults between any two phases in the winding can result in extensive damage to the winding and stator. These faults are usually caused by mechanical damage to insulation, similar to that causing ground faults, or by vibration at the end windings.

8.1.1.4 Field Ground Faults

Field ground faults cause electrical imbalances. One fault will cause no problem since the circuits are isolated, but two faults may cause a short resulting in unbalanced radial forces in the rotor. When a double ground exists, part of the field windings will be shorted through the shaft, causing magnetic or thermal imbalances.

8.1.1.5 Loss of Field

Loss of excitation causes rotor overheating unless the generator load breakers are opened quickly. The degree of heating is a function of the initial load, the manner in which the field is lost and overspeed (generator operation as an induction motor). Armature current increases as terminal voltage decreases and is accompanied by high rotor currents. High rotor currents cause high temperatures particularly across the wedges and retaining rings. Overheating of the end portions of the stator core may also result (low excitation).

8.1.1.6 Unbalanced Armature Current

Unbalanced armature current produces negative sequence currents in the stator and induces circulating currents on the surface of the rotor and in the rotor wedges. The current's magnitude depends on the degree of imbalance and armature currents. Localized heating is produced at the wedge joints, retaining ring fits and rotor surfaces.

8.1.1.7 Synchronization Errors

Synchronization errors occur when the generator is out-of-phase with the system. These cause high torques in the stator and can lead to extensive mechanical damage, depending on the degree of phase error. Generator design standards do not generally require that a machine be able to withstand the currents and mechanical forces created during incorrect phasing or synchronizing.

8.1.2 Mechanical Hazards

8.1.2.1 Retaining Rings

Retaining rings are highly stressed components that are subject to loosening at operating speed or to fracturing due to stress corrosion cracking, which may lead to failure. Water leakage can cause stress corrosion and needs to be prevented through inspection of fittings, maintenance of differential pressures between hydrogen and cooling systems and moisture elimination. Every effort should be made to prevent exposure of 18Mn-5Cr retaining rings to moisture.

8.1.2.2 Cooling Fan Fractures

Cooling fan fractures can be caused by resonant vibration. Inspection for blade and attachment degradation or discontinuities should be done during periodic inspection and NDE. Distortion of the gas flow passages should also be evaluated.

8.1.2.3 End Windings

Bracing or supports can be loosened and weakened by generator vibration and forces caused by system faults. This weakening can cause insulation wear, leading to more severe faults.

8.1.2.4 Hydrogen Seals

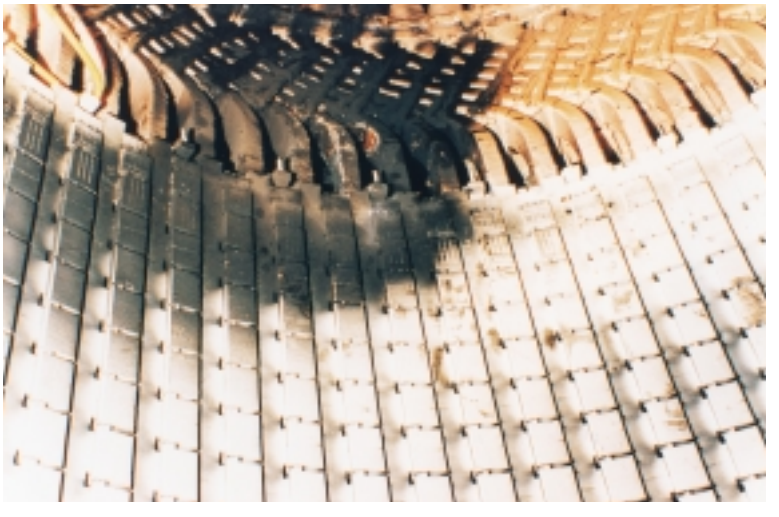
Incorrect operation of the Hydrogen Seal Oil System or inadequate maintenance can result in excessive hydrogen leakage or ingress of oil into the operating generator. Hydrogen seals should be thoroughly inspected during dismantle inspections of the generator. The seal should be completely disassembled, cleaned and refurbished as necessary. Reassembly should ensure proper axial and radial clearances. Differential pressures between hydrogen and the seal oil system should be maintained and monitored. Oil ingress into the generator can result in the need to rewind the stator due to excessive bar vibration. The generator should be removed from service if hydrogen leakage exceeds the manufacturer's recommendations.

8.1.2.5 Stator Winding Leaks

Stator winding leaks have occurred in liquid cooled generators (usually detected during hydraulic, capacitance or high potential testing) resulting in water penetration of the stator bar groundwall insulation. A periodic check or on-line instrumentation to detect excessive hydrogen flow in the stator cooling water system should be employed. The generator should be removed from service if hydrogen leakage exceeds manufacturer's recommendations.

8.1.2.6 Damage From Foreign Material

Foreign material will likely be introduced into the generator during dismantle inspections. Operating the generator with this foreign material present will damage the stator core, windings, end windings and rotor. A foreign material exclusion program should be strictly implemented during inspection and maintenance of the generator.



8.2 Protective Devices and Trip Logic

The protective devices for the mechanical and electrical hazards should be functionally tested for operability and calibrated in accordance with the manufacturer's recommendations. The following are examples:

Bearing vibration detectors and trip logic
Stator core resistance temperature detectors and thermocouples
Over voltage and ground fault relays
Overcurrent relays
Loss of generator field relaying equipment
Negative sequence current relays
Synchronization check relays

Core condition monitors
Dew Point monitors
End Winding vibration monitors
Leak detection systems
Flux probes
Partial discharge (radio-frequency) monitors

8.3 Operating Inspections

During normal operations the generator is most stressed by the combination of mechanical, electrical and magnetic forces.

1 Increased surveillance should be accomplished when monitored parameters exceed normal ranges. Required action limits should be established. Instrumentation should be periodically calibrated and trip devices functionally tested. The parameters to be monitored may include:

1. Stator voltage and current
2. Field voltage and current
3. Megawatts and megavars
4. Power factor
5. Vibration (end turn, bearings, shaft)
6. Field ground detection
7. Field temperature
8. Hydrogen pressure, moisture and purity
9. Dew point
10. Differential pressures (stator water to H_2 gas, H_2 cooler cooling water to H_2 gas, seal oil to H_2 gas)
11. Hydrogen temperature
12. Cooling water temperature to and from hydrogen coolers
13. Hydrogen temperature to and from coolers
14. Frequency
15. Stator cooling water flow, pressure and temperature (liquid cooled stator)
16. Stator RTD temperature
17. Stator cooling water conductivity
18. Stator slot gas discharge temperatures (gas cooled stator)
19. Core condition monitor
20. Partial discharge monitor
21. Shorted turns monitor
22. Stator leak monitoring system
23. Flux probe

2 Periodic operating inspections should include:

1. A visual inspection of the overall installation and operation of the generator, generator protection system and associated circuit breakers.
2. Instrumentation for loading, temperatures, pressures and vibrations.
3. Identification of any unusual noises and/or vibrations.
4. A review of general housekeeping in the surrounding area. Evidence of excessive dirt, dust, moisture, oil, fumes or inadequate ventilation should be noted.
5. A check for evidence of sparking or chattering of brush assemblies.
6. An inspection for evidence of sparking and wear of slip rings.
7. Evaluation of seal oil, stator (rotor) cooling and hydrogen cooling (pressure, temperature and flow).

8. A check that calibrations of protective devices and instrumentation are up to date.
9. Verification that manufacturer's operating parameters are not exceeded.
10. Proper function of the shaft grounding system.

8.4 Generator Dismantle Inspections

During rotor removal and replacement, care must be exercised to avoid damaging core punchings, stator windings, bearings, collectors, rotor, bearing journals or retaining rings. The rotor should be protected from moisture and an FME program implemented. A review of prior dismantle inspection reports should be performed to identify issues to be addressed/evaluated during the dismantle inspection.

8.4.1 Pre-dismantle

A comprehensive review of the main electrical generator and support systems' performance should be periodically conducted and trending accomplished. This review should include:

1. Instrumentation calibration reports
2. Electrical test reports
3. Generator maintenance repair/overhaul reports
4. Circuit breaker and relay maintenance, calibration and coordination reports
5. Infrared thermal imaging reports
6. Non-destructive examination test reports
7. Technical information bulletins
8. Work requests
9. Surveillance test results for support systems and protective systems
10. Robotic inspection reports
11. Operator logs for abnormal conditions
12. Review of manufacturers' service and operating experience reports

8.4.2 Dismantle Inspection

When the main electrical generator is dismantled for periodic inspection the following should be reviewed:

1. A check for loose or missing stator wedges. Examination for burns, wear or unusual signs of damage. A check of loose coils in the slot.
2. Evidence of moisture, water leakage, dirt, abrasions, oil or grease on the stator (armature) winding or main terminal connections should be noted. Stator structural parts should be inspected for evidence of hot spots or damaged punchings. Insulated bolts should be tested for deterioration. Verification of clamping fixture tightness should also be performed.
3. A check of insulation surfaces for cracks, flaking, powdering, tape migration and signs of corona.
4. Inspection of blocking ties and coil support rings in the stator.
5. Inspection of stator iron for hot spots or mechanical damage.
6. Inspection of stator for loose through-bolts or core iron.
7. A bearing check for effects of wear, temperature and/or lubrication.
8. Shaft ground testing.
9. Fan blower non-destructive examination (NDE) and proper installation.
10. Examination of the shaft performed per manufacturer's requirements.
11. Retaining rings and end discs non-destructive examination (NDE) and inspection for evidence of moisture, stains, pitting and hot spots. 18Mn-5Cr retaining rings should be completely

examined (interior and exterior surface) and the station should implement an effective moisture protection program for 18Mn-5Cr retaining rings or replace with 18Mn-18Cr retaining rings. If retaining rings are subjected to moisture (high dew points), reinspect the interior and exterior surfaces to verify no cracking or pitting has occurred.

12 An examination for hot spots, movement or distortion of field coils, leakage and end winding blocking on the rotor should be performed. Ventilation ducts, wedging and contact surfaces between wedges, retaining ring and rotor body should be examined.

13 Rotor surfaces such as journals and coupling surface should be inspected for wear or pitting. The collector rings and field leads should be cleaned and inspected and hydrogen seal integrity verified.

14 Check the shaft for scoring, rubbing, discoloration, excessive wear and oxidation.

15 A coupling check for elongation or galling of bolt holes and inspection for cracking between bolt holes.

16 The rotor should be properly laid up, with proper protection from moisture and contaminants upon removal.

17 Maintenance should be performed on generator main leads per manufacturer's recommendations.

18 Material handling equipment should be functionally tested and should meet specifications for the lifts to be performed.

19 The stator lead box and terminal bushing should be thoroughly inspected for cracks and looseness. Cooling passageways should be visually inspected and signs of deterioration of insulation and blocking evaluated.

20 A complete inspection of hydrogen seals should be conducted. This includes dismantle, cleaning and refurbishing or replacement. Shaft and seal ring wearing surfaces should be carefully inspected for pitting, alignment and wear.

21 All generator monitoring and protective instrumentation should be checked and calibrated.

22 The generator support systems maintenance should be performed in accordance with manufacturer's recommendations and operating experience.

23 Alignment checks should be performed if alignments were altered during disassembly.

24 Visual inspection of the generator should be performed to ensure no foreign material remains in the stator.

8.4.3 Post-Dismantle Inspections

After completion of the dismantle inspection, the following should be considered:

1 The operability of all generator support systems should be verified.

2 Trip set points should be verified to be within specified values.

3 A post-dismantle review should be performed and should include:

1 Critical parts that have been replaced or modified, with reasons for changes determined.

2 Components scheduled for replacement or repair at future outages.

3 A review of the final manufacturer's dismantle inspection results/report including recommendations for future dismantle inspections.

4 An evaluation of which manufacturer's recommendations were implemented and those that were not. Reasons for not implementing recommendations should be reviewed.

5 Manufacturer's technical information communications and status.

6 A review of inventory of spare parts and consumables.

8.5 Robotic Inspections

Effective generator robotic inspection capabilities have been developed. Robotic capability allows for inspection of the generator without rotor removal and with minimal disassembly. Additionally, nondestructive examination of retaining rings and rotor teeth can be accomplished. Verification of core torque, winding hydraulic integrity, wedge tightness and enhanced visual inspection can also be supported. Electrical testing and support systems maintenance is performed as it would during a dismantle inspection. Robotic inspections are particularly effective when operating inspections are supported with on-line diagnostic monitoring for component condition assessments.

1. The generator manufacturer should confirm the availability of effective robotic inspection equipment.
2. Support system maintenance and electrical testing should be completed according to manufacturer's recommendations.

8.6 Electrical Testing

The following electrical tests should be conducted on the main electrical generator. The test results should be trended and compared to previous electrical test results. The trend is considered more important than the absolute value of a single test. The manufacturer's recommended electrical test regimen should be evaluated.

Insulation Resistance measures the condition of the insulation between the conductor and the ground. Low values indicate moisture, dirt or damaged insulation. Test voltages should be higher than the generator rated voltage, preferably by a factor of two. All insulation resistance readings should be temperature corrected. Insulation resistance of the stator and field windings, bearings and hydrogen seal insulation should be tested.

Polarization Index test provides additional information on the condition of insulation between the conductor and ground. Polarization Index is the ratio of insulation resistance for ten minutes and one minute. Low polarization index readings indicate wet or dirty windings.

Stator Resistance Temperature Detector Element Copper resistance and ground insulation testing to ensure calibration, connections and insulation condition are satisfactory.

Field and Stator Windings Copper Resistance to check for poor connections and breaks.

DC Leakage Current measurements for detection of contamination and or deterioration should be considered if Polarization Index values are low.

Hydraulic integrity of water cooled stator windings should be verified if the generator manufacturer has experienced leakage with stator bars and/or hydraulic connections.

8.6.1 Dismantle/Robotic Inspection Electrical Testing

In addition to the routine electrical testing completed during refueling/maintenance outages, the following electrical tests should be accomplished in conjunction with a dismantle (field removed from stator bore) or robotic inspection. The manufacturer's electrical test regimen should be followed.

Electromagnetic Core Imperfection Detection/Ring or Loop Test to detect potential areas of elevated temperature due to shorts across the core laminations.

Wedge Tightness Evaluation to detect deterioration or looseness in the wedging support system for the stator bars. Typically the core wedge tightness is mapped.

Stator Winding AC Over potential Test to verify integrity of the groundwall insulation integrity and readiness for return of the generator to commercial service.

Partial Discharge Testing to detect localized deterioration in the stator winding insulation.

Frequency Response Testing of the end windings to verify that resonance will not occur during operation.

Pole Balance/Air Gap Flux Probe to verify the integrity of field inter-turn insulation.

Stator Bar Cooling Medium (water/gas) Flow Testing to verify sufficient flow for bar cooling.

8.7 Hydrogen Cooling System

1. Periodic hydrogen leak testing should be performed.
2. Hydrogen leakage rates should be trended and evaluated.
    1. A calibrated, properly operating H_2/air/CO_2 analyzer should be used to monitor vent paths to determine atmospheric conditions within the generator during purging.
    2. The analyzer should be calibrated with known concentrations of H_2/air/CO_2 prior to gas exchange evolutions.
3. Hydrogen cooler performance should be evaluated periodically and trended to determine the need for cleaning/maintenance.
4. The hydrogen coolers should be periodically cleaned and subjected to NDE evaluations.
5. The hydrogen cooling water temperature control valve (and actuator) should be periodically maintained and tested.
6. Hydrogen cooler cooling water flow rates should be monitored.
7. Hydrogen cooler temperature control valve operation should be set to maintain generator cooling gas relative humidity.
8. Performance of the hydrogen dryers should be monitored. Hydrogen dryers are considered an important system especially when supporting generators with 18Mn-5Cr retaining rings.
9. Instrumentation, control equipment and annunciator inputs associated with the hydrogen gas, cooling and dryer components should be functionally tested and calibrated including annunciator verifications.
10. Operator rounds should include verification of normal operations including channel checks of instruments.
11. Hydrogen pressure, purity, and the core monitor should be periodically checked during operator rounds. These parameters should be alarmed to the control room.

8.8 Stator/Rotor Cooling Water

1. The temperature and/or pressure control valves and actuators should be subject to periodic preventive maintenance.
2. Water pressure should be maintained in the generator below hydrogen pressures.
3. Cooling water to the heat exchangers should be maintained at a lower pressure than the stator water.
4. All annunciators, instrumentation (local and control room) and automatic features (i.e., pump starts) should be periodically calibrated and functionally tested, including alarm verification.
5. Operator rounds should typically include verifying the following parameters for normal system operation: (including channel checks of instruments, where possible)

1. Flow
2. Conductivity/chemistry
3. Discharge pressure
4. Filter status and differential pressure(s)
5. Demineralizer flow and differential pressure(s)
6. Temperature
7. Tank level/pressure
8. Generator leak detection

6. Pump performance should be monitored and trended.
7. Periodic cleaning and pressure testing should be performed on stator cooling water heat exchangers.
8. The following procedures should address normal/abnormal conditions:

1. System startup
2. System shutdown
3. Pump start testing (automatic pump starts)
4. Pump operational rotation
5. High conductivity
6. High temperature
7. Low flow/pressure
8. High and low tank level
9. Operations necessary for removing or placing demineralizers in service
10. Operations necessary for removing or placing stator cooling water heat exchangers in service with the main generator on-line
11. System drainage
12. Leak detection

9. Strainers (if installed) should be periodically inspected and cleaned.
10. Periodic demineralizer resin and filter changeouts should be accomplished.
11. All generator protection circuits involving stator cooling water should be periodically calibrated and functionally tested.
12. Pressure control valves (if provided) should be equipped with mechanical stops to prevent the valve from fully closing, thereby removing all cooling water from energized stator windings.

8.9 Hydrogen Seal Oil

1. Temperature and pressure control valves (regulators) should be monitored and maintained.
2. Relief valves should be tested.
3. Check valves should be tested.
4. Seal oil coolers should be cleaned and tested.
5. Air/hydrogen detraining sections and/or float traps, drain regulators and defoaming and vacuum tanks should be visually inspection, cleaned and maintained.
6. Automatic functions such as pump starts, alternate oil supplies and/or automatic regulator operation should be tested.
7. Pump performance should be monitored and trended.
8. The following procedures should address normal/abnormal conditions:

1. System startup
2. System shutdown
3. Pump start testing
4. Surveillance tests

5 Seal oil low pressure
6 Seal oil high temperature
7 High and low tank levels
8 Loss of seal oil
9 Loss of hydrogen extraction ventilator

9 All annunciators and instrumentation (local and control room) should be periodically calibrated and tested.

10 Drains associated with the seal oil system should be equipped with threaded caps.

8.10 Isolated Phase Bus Duct Cooling

1 Fans, motors, filters and heat exchangers should be subject to periodic preventive maintenance.

2 All annunciators (local and/or control room) and instrumentation should be subject to periodic calibration, including alarm verifications.

3 Operator rounds should include normal operational verifications of the bus duct cooling system.

4 The following procedures should address normal/abnormal conditions:

1 System startup
2 System shutdown
3 Fan automatic start testing
4 Fan operational rotation
5 High temperature/low flow
6 Loss of bus duct cooling/ventilation
7 Hydrogen infiltration into the isolated phase bus ducts

5 Failure of the cooling/ventilation system should be alarmed to the main control room.

6 Surge arresters connected to the isolated phase bus duct system should be explosion-proof and the casings equipped with pressure reliefs.

7 The isolated phase bus duct system should be equipped with hydrogen detectors to ensure hydrogen ingress into system is detected.

Chapter 9 – Electrical Transformers (oil-filled)

9.0 General

There is no recognized single indicator to accurately predict transformer failure. The use of gas-in-oil testing results, infra-red thermography, transformer oil screening, electrical testing and preventive maintenance of the transformer's constituent parts provide a good foundation for an effective transformer loss prevention program.

1. One engineer (or department) should have overall responsibility for the large oil-immersed transformer program. Responsibilities should include:
    1. Establishing or reviewing the scope of maintenance and testing tasks
    2. Ensuring completion of maintenance and testing
    3. Evaluating operational and performance data

9.1 Operating Hazards

9.1.1 High Oil Temperature

Transformer components and systems should be operated such that:

1. Energized transformer tank oil temperature is maintained within the range of 45°C to 85°C
2. Winding hot-spot temperature is limited to 100°C

9.1.2 Static Electrification of Oil

Oil Static-Electrification relates to the electrostatic charging tendency of dry transformer oil flowing across dry cellulose insulation and press-board inside a large transformer. Both shell-form and core-form transformers can be susceptible to the problem.

1. Manufacturer's advice should be sought to determine if transformers are susceptible during power operations and backfeeding.
2. Procedures should address oil pump and fan sequencing for susceptible transformers such that minimal fans/pumps operate below 40°C and all pumps/fans operate above 80°C.
3. Periodically perform an oil test for static charge buildup or electrostatic charging tendency. If a transformer is found to exhibit a high or steadily increasing ECT (electrostatic charging tendency):
    1. Trend the relationship between moisture-in-oil, level, oil temperature and ECT, and
    2. Reduce the pump impeller size, or
    3. Install more and smaller displacement oil pumps.

9.1.3 Power Backfeeding

During backfeed, with the generator and its neutral ground isolated, the generator bus may be left without a system neutral ground (when the main transformer is delta-wound). Such a system is only grounded by its capacitance to ground and is vulnerable to severe transient over-voltages. Excessive transient over-voltages may result from switching operations or intermittent faults. Special protection devices may need to be installed during backfeed operations. Procedures should be developed to activate needed backfeed protection relays prior to backfeed and to isolate backfeed protection relays prior to putting the generator back in service.

9.1.4 Geomagnetically Induced Currents

Geomagnetic storms are naturally-occurring phenomena that can adversely affect 50-Hz and 60-Hz AC electric power systems. Cyclic variations in solar sunspot activity cause transient disturbances in the earth's dipole magnetic field. Charged particles (released by the sun in the form of a solar-flare) interact with the earth's rotating magnetic field and induce a variable DC electric potential across the earth's surface. This varying DC voltage induces a quasi-DC current within "long" transmission and distribution lines. This quasi-DC current is known as GIC (geomagnetically induced current).

A plant may be susceptible to GIC influences if:

1. GIC is not included in the design rating of the transformers, or
2. If the following three conditions exist:
    1. It is located in northern latitudes and plant transmission lines are located in areas of igneous rock formation
    2. There are long stretches of transmission lines oriented north-south
    3. There are single-phase transformers.

The station should determine the susceptibility of the transformers to GIC. If the transformers are susceptible to GIC, procedures should be established to respond to the GIC potential.

9.1.5 Overexcitation Prevention

Overexcitation can cause a transformer failure. Overexcitation causes winding hot-spots, cellulose overheating and stray eddy-current heating of metal surfaces. Transformers should be designed to operate at 110% of rated secondary voltage at zero load. There should be a transformer overexcitation trip for large oil-filled power transformers set at 125% (or less) overexcitation based upon volts-per-hertz detection relays.

9.1.6 Lightning/Surge Protection

Surge arresters provide the first level of protection for the transformer. Surge arresters are needed to preserve the surge withstand capability (i.e., overvoltage) of electrical power and control circuits. They should prevent an external electrical surge from overloading or faulting the device they protect.

1. Surge arresters should be provided for the protection of plant components and maintained in accordance with manufacturer's recommendations.
2. Surge arresters should be periodically tested to verify dielectric capability.

9.2 Operating Inspections

Periodic inspection of transformers should be incorporated into the preventive maintenance program. The following inspections should be performed:

1. Transformer tank oil level
2. External grounding straps
3. Transformer inert gas blanket pressure
4. Signs of any mechanical or relay safety device actuation
5. Thermometer and gauge operation
6. In-line oil monitoring equipment operation
7. Transformer oil coolers, pumps and fans
8. Pneumatic circuit breaker gas pressure
9. Transformer and circuit breaker bushings
10. Lightning and surge arresters
11. Desiccant conditions

9.2.1 Winding Temperature Operational Limits

1. Transformer winding hot-spot temperature alarm should be set at a maximum of 110°C.
2. Transformers should be sized to handle at least 110% of rated load at 0.9 power factor.
3. Cooling equipment should be sequenced to maintain winding temperatures within manufacturer's recommendation.

9.2.2 Protective Relays

1. Protective relays should be provided to:
   1. Isolate external electrical faults or transients from affecting the transformer.
   2. Isolate a faulted transformer from affecting the rest of the electrical system.
2. These devices, including alarm functions, should be periodically calibrated and tested.

9.2.3 Grounding Grid Integrity

The grounding system design should ensure protection against damage due to lightning strikes, touch and step voltages in outdoor areas, circulating ground currents and buried structures. Ground voltages may be transferred into and out of the station by buried piping, cable ground and neutral wires, control cable shields, telephone lines, railroad tracks and other metal structures.

1. The following should be performed periodically:
   1. Visual inspection of ground straps.
   2. Ground continuity testing of the grounding system.
   3. Evaluation of cathodic protection system relative to grounding grid coupling.
   4. Evaluation of voltage risers between plant grounding grid and substation grounding grids.

9.3 Preventive Maintenance

9.3.1 Dissolved Gas Monitoring

Dissolved gases in transformer oil are an indicator of degradation of the cellulosic insulation around the windings, deterioration of the insulating oil, or both. Gas chromatography is used for detection and measurement of dissolved gases and provides indication of incipient fault conditions. Once the type of fault is diagnosed, appropriate actions should be taken to minimize the incipient condition from progressing to a through-fault.

1. A representative sample of oil should periodically be taken from the transformers and analyzed.
2. If continuous in-line dissolved gas detection and monitoring is installed:
    1. Equipment should be installed and calibrated to manufacturer's specifications.
    2. Local readings of the in-line dissolved gas detection system should be taken periodically, recorded and trended.
    3. Manual samples should be taken concurrent with the operation of the in-line system before it is used exclusively for detecting dissolved gases.
    4. Periodically, an oil sample should be taken and analyzed, using laboratory methods for dissolved gases, and a cross-comparison should be performed of in-line equipment data to laboratory analysis.
    5. Alarms based upon key gas concentrations should be established.
    6. Alarm response procedures should be established including the request for manual sampling.
3. If sampling for dissolved gases is performed manually:
    1. For main station transformers without indications of a problem, sampling and analysis frequencies for dissolved gases and moisture should be based upon manufacturer's recommendations and national standards.
    2. The sampling procedure should ensure that accurate, representative samples of oil in the transformer are taken. The following should be considered:
        1. Sample containers should be clean and moisture-free.
        2. The use of galvanized fittings in the sampling stream should be avoided.
        3. Before sampling, the sample valve should be adequately flushed.
        4. Care should be taken in drawing samples to prevent contamination (dirt, moisture, etc.).
        5. Disposal of sample wastes.
        6. Each sample should be labeled with:
            1. Date of sample
            2. Oil temperature
            3. Electrical load
            4. Transformer serial number
    7. Oil samples should be protected from sunlight.
4. As part of the dissolved gas analysis program, action levels with associated sample frequencies and corrective actions should be established.
    1. Exceeding a single gas concentration limit (except acetylene or CO_2 / CO ratio) is not cause to initiate the sampling and corrective actions required by the next condition level, nor should progressive corrective actions be delayed until all limits are exceeded. Any sudden or unexplained increase in any one gas should be evaluated, as should the ratio among the combustible gases.

2 If the oil test limits are exceeded, there should be a re-sampling. If the results of the re-sample agree with the initial test results, the maintenance and operational history of the transformer should be reviewed and the manufacturer's advice sought.

5 Dissolved gas sample results should be trended. The following should be considered:

1 Individual combustible gas
2 Gas ratios, including CO_2 / CO ratio
3 Rate of change of gassing
4 Nitrogen usage rate
5 Load on the transformer at the time of the sample
6 Temperature of oil at time of sample
7 Determine water-in-oil at the specific sample temperature

9.3.2 Fans, Oil Coolers and Oil Pumps

Fans, oil coolers and oil pumps should be periodically inspected, tested and cleaned.

9.3.3 Bushing and Insulator Cleaning

The ability of bushings/insulators to function properly depends on their physical integrity (lack of cracks, oil leaks, etc.) and on the lack of foreign material deposited on their surfaces. Manufacturer's recommendations should be followed for inspection and cleaning of bushings and insulators.

9.3.4 Transformer Tank Internal Inspections

Internal inspections should only be performed when suspected problems have been identified through preventive maintenance testing results, since there is potential to do harm to the transformer once the oil is drained and it is exposed to moisture and oxygen under atmospheric conditions. The transformer manufacturer should be consulted regarding precautions to be taken, including implementation of a foreign material exclusion program.

9.4 Electrical Testing

1 Transformers should be electrically tested in accordance with manufacturer's recommendations. The following electrical tests should be considered:

1 Transformer core ground and insulation resistance:
2 Transformer polarity/phase/ turns ratio.
3 Single-phase exciting current
4 Winding resistance
5 Insulation resistance/ polarization index
6 Winding power factor
7 Winding capacitance

2 Instrument transformers should be tested in accordance with manufacturer's recommendations for accuracy and differential relaying protective features.

3 Where possible, bushing-type CTs (current transformers) should be tested for polarity, winding and lead resistance, exciting current and turns ratio.

4 Voltage transformers should be tested for ratio and phase angle.

5 Proof testing of large oil-filled transformers, related instrument transformers and electrical bushings should be performed in accordance with manufacturer's recommendations.

6 Bushings should be electrically tested in accordance with manufacturer's recommendations. Power factor and capacitance tests should be considered.

Chapter 10 – Switchyard and Electrical Equipment

10.0 General

Failure of power transmission equipment may be significant from both an economic and a safety standpoint. Reliable and redundant power supplies to nuclear safety systems must be provided at all times. Off-site power sources to the nuclear station should be physically separate and backed up by separate and independent on-site safety-related power supply systems.

1 A minimum of two independent and physically separate electrical circuits should be available from the off-site transmission system to the on-site safety-related electrical distribution system.

1 Design and location of the grid connections should be arranged such that a single failure occurrence inside one electrical power supply system cannot cause an interruption of all grid connections.

2 Load assignment should be such that the safety actions of each group are redundant and independent.

2 Emergency and spare grid connections may be common for several units. In this case their capacity should be sufficient to supply emergency power to all these units in parallel.

3 The electrical circuits should be designed and arranged to support performing maintenance on a circuit breaker without taking down the line or losing electrical redundancy.

4 Separate and independent on-site AC generation sources, each of sufficient rating (voltage, frequency and power) to supply power to their safety-related electrical distribution systems, should be provided in the event of failure of all off-site power supplies.

5 Design and protection of the switchyard and electrical equipment should fulfill the following requirements:

1 Switchyard equipment should be designed to withstand the worst expected environmental conditions for the location (storm, ice, earthquake, salt, dust, etc.).

2 Voltage and frequency limited to values necessary for safe operation of all connected electrical loads.

3 Short circuit and overload currents limited according to the requirements of all connected electrical loads.

4 Transient voltage, frequency and current caused by normal operation should not trip the protection devices nor start automatic switch-over to the emergency power supply (including emergency diesel generators).

5 The current-transformer (CT) ratio should be sized large enough so that the CT secondary current does not exceed 20 times the rated current under the maximum symmetrical primary fault current.

6 Responsibilities for switchyard operation and maintenance should be defined and should address the following:

1. Equipment clearance process
2. Work planning and scheduling interface
3. Nuclear Plant Control Room notifications
4. Emergency work

10.1 Operating Hazards

1. Protection against voltage variations, frequency variation, voltage or current harmonics, and short-circuit currents should be provided. Transformers and electrical circuits are fault-protected by the action of mechanical and electrical devices. They are normally triggered into action by relays. Relay response under distorted conditions may result in some of the following effects:

   - Relays operate slower and/or with higher pickup values
   - Static under-frequency relays are susceptible to substantial changes in operating characteristics
   - Changes are normally small at 5% harmonic content or less
   - Over-voltage and over-current relays exhibit different changes in operating characteristics
   - Operating torques of relays are sometimes reversed
   - Balanced beam impedance relays show both overreach and underreach, depending on the distortion
   - Harmonics sometimes impair the high-speed operation of differential relays

2. The grounding system design should ensure protection from lightning strikes, “touch-and-step” voltages in outdoor areas, circulating ground currents and buried structures. Substation structures are generally protected from lightning by an overhead ground wire and mast system, while “touch-and-step” voltage protection is provided by bonding the structure and equipment to the ground mat.

3. Many disturbances and damages to electrical equipment are caused by abnormally high voltage surges; the most severe over-voltages are caused by lightning and switching surges. Surge protection should be provided. The surge arresters should be situated as close as possible to the equipment to be protected.

   1. Substation equipment should be protected from over-voltage damages by the following methods:

      1. Use of surge arresters
      2. Equipment-neutral grounding
      3. Proper selection of equipment impulse insulation level
      4. Careful study of the expected switching-surge levels

10.2 Operating Inspections

Periodic inspection of switchyard equipment is part of an effective preventive maintenance program. Aging and service wear effects can be readily identified during periodic inspection and testing. Inspected switchyard equipment should include:

1. Electrical connections, wiring and grounding straps should be adequately secured and undamaged. Circuit breaker bulk oil tank heaters or SF6 gas/seal heaters should be operational.
2. Pneumatic circuit breaker gas pressure is adequate to operate breaker (if called upon to actuate); record any gas additions performed.
3. Transformer and circuit breaker bushings:
    1. Surfaces do not show signs of partial discharge or corona.
    2. Gaskets are not discolored, loose or deteriorating.
    3. Oil levels are adequate.
4. Deluge fire protection system spray head orientation is proper.
5. Lightning and surge arrester surfaces and electrical cabling are proper.
6. Lightning strike counters are electrically connected and functional (if applicable).
7. Tasks to be performed periodically:
    1. Record circuit breaker operation counter.
    2. Record circuit breaker gas compressor running time and cycling frequency.
    3. Record gas compressor oil levels.
    4. Monitor desiccant condition.
8. Transformers should be visually inspected.

10.3 Electrical Testing

Manufacturer's recommendations, component aging studies, component importance measures derived from probabilistic safety assessments and analysis of past maintenance may help to determine electrical testing intervals for equipment. The following should be considered:

1. Thermography of switchyard equipment
2. Testing of transformers
3. Calibration and functional test of instruments and relays
4. Inspection and testing of circuit breakers, including consideration of:
    1. In-service electrical circuit breaker timing tests.
    2. Bushing-to-bushing contact resistance measurements.
    3. Power factor testing (including SF6 circuit breakers with grading capacitors, but not single contact SF6 circuit breakers).
    4. Manufacturer's recommendations when performing major dismantle maintenance.
5. Calibration and testing of protective relays and interlocks.
6. Inspection and testing of instrument transformers.
    1. Where possible, bushing-type CTs (current transformers) should be tested for polarity, winding and lead resistance, exciting current and turns ratio. Ensure that the exciting current does not exceed 125% of the typical curve value; only maintain voltages long enough to take readings.
    2. Voltage transformers should be tested for ratio and phase angle.
    3. Dry transformers should be internally inspected for cleanliness and subjected to an insulation resistance/power factor test.
7. The following should be considered for oil-impregnated, paper-insulated, capacitance-graded bushings used on large transformers and circuit breakers.
    1. For uncoated porcelain bushings: power factor and capacitance test.
    2. For coated bushings: if periodic testing is applicable, follow manufacturer's recommendations.

8 Periodically perform voltage and current harmonic signatures on AC electrical buses. This should also be done when major new non-linear loads (e.g., solid-state motor controllers) are introduced to the bus or when new protective relay technology is introduced, such as solid-state devices replacing electro-mechanical devices. Re-evaluate allowable transformer loading and protective relay response when harmonic content changes significantly.

9 Metal-oxide semiconductor surge arresters should be periodically tested to verify dielectric capability.

10 The grounding system design should ensure protection from lightning strikes, "touch-and-step" voltages in outdoor areas, circulating ground currents and buried structures.

1 Periodic visual inspection of the ground straps.

2 Periodic station ground continuity tests.

3 Periodic evaluation of cathodic protection system relative to grounding grid coupling. (Measures should be taken to avoid any stray current interference problems to cathodic protected structures which are electrically isolated from the ground mat.)

4 Periodic ground-mat studies should be performed to determine if a ground-mat will limit the neutral-to-ground voltages during ground faults.

5 Periodic evaluation of voltage risers between plant grounding grid and substation grounding grids.

1 Tin-coated bare copper cable should be used to minimize the potential difference between steel structures and the ground cable.

2 If the switchyard is outside the generating station ground grid, at least 2 connections should be made between the two ground systems.

6 Periodic testing of earth resistance ground. This should also be performed when major changes in relay technology are introduced, such as converting from electro-mechanical relays to solid-state relays, or when energy efficient solid-state motor controllers are installed on large load motors.

10.4 Mechanical Maintenance

Manufacturer's recommendations, component aging studies, component importance measures derived from probabilistic safety assessments and analysis of past maintenance may help to determine testing intervals for equipment. The following should be considered:

1 Inspection and testing of circuit breakers

1 Periodically:

1 Sample tank oil and perform screening tests on oil-filled circuit breakers.

2 Sample the moisture in the gas of SF_6 and air-blast circuit breakers.

3 Except for SF_6 circuit breakers, remotely cycle the circuit breaker to exercise the mechanical seals (this may be omitted if the breaker has automatically operated during an annual interval).

4 Inspect circuit breaker compressed gas system for erosion and corrosion.

2 Functionally test operation and perform minor maintenance per manufacturer's recommendations, including:

1 Sonic or Freon leak detection on air-operated or SF_6 circuit breakers

2 Lubricate mechanical components

3 Bushing-to-bushing contact resistance measurements

3 Perform major dismantle maintenance per manufacturer's recommendations.

2 Periodically clean electrical bushings and insulators. If protective coatings are applied, follow manufacturer's recommendations.

Chapter 11 – Large Motors and Emergency Generators (>1MWe)

11.0 General

The large motor/generator monitoring program should address:

1. Visual inspection
2. Equipment dismantle following component failure to determine cause
3. Trending of mechanical and electrical test results from operational surveillance
4. Oil/grease analysis.

11.1 Operating Hazards

Synchronization of the generator out-of-phase can cause major damage to the generator. Recent industry experience has indicated that most motor breakdowns result from:

1. Bearing-related failures 44%
2. Stator-related failures 26%
3. Rotor-related failures 8%

Other industry data bases show that mechanical failures occur twice as frequently as electrical failures.

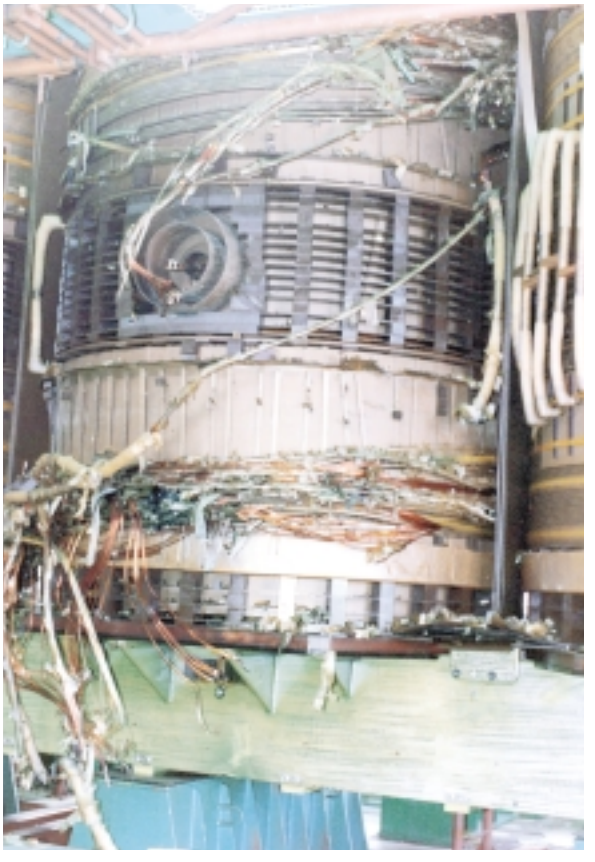
Not all electric motors in a nuclear power plant will be subject to the full scope of the electrical motor/generator preventive maintenance program. Selected components may be designated as run-to-failure. A priority schedule for the motor/generator test program should exist to address the priority of safety-related and power-generation-limiting motors and generators.

11.2 Operating Inspections

1. Inspections, testing and preventive maintenance should be in accordance with manufacturer's recommendations. The following operational data should be considered for trending:
    1. Supply voltage
    2. Running current
    3. Speed
    4. Bearing temperature
    5. Winding temperature
    6. Frequency
    7. Power
    8. Battery system condition
2. Routine operating surveillance of motors should include verification of operating oil level, checks for oil leakage, air cooling passageway obstructions and a check for normal sound and odor.
3. Visual inspection of the motor end-winding region should be accomplished with the motor de-energized to allow observation of the winding ties and evidence of loose coils, such as dusting in the coil support regions of the motor.
4. The motor may be disassembled for inspection.

5 Alignment checks will be necessary when high vibration is apparent or if maintenance resulted in changes in alignment.

11.3 Electrical Testing



No one electrical test is considered the best available for motor or generator testing. Diagnostic electrical tests are specific to the area of investigation. The absolute value of a single electrical test is considered less revealing than the trend over time. Alert and Action levels should be identified for the monitored parameters and electrical test results. Specific requirements including increased frequency of monitoring and removal of equipment from service should be defined. Periodic electrical testing with trending of electrical test results should be accomplished for critical motors and emergency electrical generators. The following electrical tests should be considered for inclusion in the test program:

Insulation Resistance measures the condition of the insulation between the conductor and the ground. Low values indicate moisture, dirt or damaged insulation. Test voltages should be higher than rated voltage preferably twice rated. All insulation resistance readings should be temperature corrected.

Polarization Index Test provides additional information on the condition of insulation between the conductor and ground. Polarization Index is the ratio of insulation resistance for ten minutes and one minute. A ratio of two or more indicates suitability for service and a failure of the test typically indicates wet or dirty insulation. Recommended values depend on the class of insulation.

Current Analysis can show the presence of cracked or broken rotor bars. Manufacturing defects should be determined with an initial benchmark test. Large pump motors equipped with heavy flywheels can develop rotor winding problems because of their long acceleration time with high starting currents.

DC High Potential is a more thorough test on the condition of the insulation between conductor and ground and is typically used on motors with rated voltage above 4kV. Step voltage test is considered the most effective with the performer of the test capable of detecting impending failure of the motor prior to actual failure (allowing abortion of the test prior to failure). This is a controlled overvoltage test with voltage increments applied over time and leakage current measured.

Winding Resistance Test is performed to detect high resistance connections before they develop into connection or winding failure. This will also detect imbalances between phase windings.

Partial Discharge Testing indicates voids in the insulation, which relates to insulation deterioration.

11.4 Diagnostic Testing

Several other electrical tests may be conducted to diagnose deteriorating trends in motor/generator performance. The following provides a list of diagnostic tests for consideration:

1. **AC High Potential:** Overvoltage test to measure leakage current
2. **Power Factor Test:** AC Test to measure insulation power factor
3. **Dissipation Factor and Capacitance Tests:** AC Test to measure dissipation capacitance
4. **Partial Discharge:** AC test to measure corona
5. **Electromagnetic Core Imperfection Detection Test (EL-CID):** Test for shorted stator core laminations
6. **Rotor Winding Integrity Test**
7. **Surge Comparison Test:** Test of the turn-to-turn insulation
8. **Vibration Analysis**

Chapter 12 – Emergency Prime Movers

12. 0 General

The emergency power system provides an independent supply of power to ensure the availability and operability of safety systems. The emergency power system includes an electrical generator driven by a prime mover, usually a diesel engine or gas turbine. Normally this entire system is subject to close regulatory scrutiny.

12.1 Operating Hazards

Significant machinery breakdown damages may occur as a result of any of the following:

1. Synchronization out of phase
2. Loss of lubrication or cooling
3. Water leakage into cylinder(s)
4. Overspeed
5. Uneven thermal expansion
6. Local overheating
7. Stall flutter
8. Foreign material ingestion
9. Poor quality fuel

12.2 Operating Inspections

12.2.1 Diesels

1. The following should be monitored, recorded and trended:
    1. Lube oil temperature, level, pressure and differential pressure across filter
    2. Cooling water temperature, pressure, flow, and level
    3. Fuel pressure, level and differential pressure across filter
    4. Crankcase mist detector
    5. Engine speed
    6. Starting air system pressure
    7. Exhaust gas temperature
2. The following operating and technical aspects should be considered:
    1. The cooling water and the lube oil should be pre-heated to the required minimum values, automatic temperature adjustment of the cooling water and warming of the jacket by means of a heater and circulation pump.
    2. The crankcase ventilation should prevent the introduction of foreign material. Overpressure protection should be provided.
    3. Run-down of the diesel should be accomplished with sufficient time to allow even cool-down.

12.2.2 Gas Turbines

1 The following should be monitored, recorded and trended:

1 Vibration
2 Combustion air filter differential pressure
4 Compressor pressure and temperature
5 Exhaust gas temperature
6 Cooling air flow
7 Lubricant pressure and temperature
8 Bearing temperature
9 Fuel pressure

2 The following operating and technical aspects should be considered:

1 The engine should be protected from condensation. If necessary, warm, dry air should be blown into the turbine.
2 Filtered combustion air and high quality fuel should be used to minimize high temperature corrosion.
3 Lube oil should be pre-heated.

12.3 Maintenance

Maintenance of the engine and auxiliary systems (e.g., cooler, pumps, compressors, cases) should be performed in accordance with regulatory requirements, manufacturers' recommendations, operational experience and equipment performance monitoring.

12.3.1 Dismantle Inspections

Dismantle inspections should be conducted in accordance with the manufacturers' recommendations.

12.3.2 Gas Turbine Partial Inspections

During partial inspections, all vital and hot components and safety devices should be checked in accordance with manufacturers' recommendations.

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