NUREG-0824

Integrated Plant Safety Assessment
Systematic Evaluation Program

Millstone Nuclear Power Station, Unit 1

Northeast Nuclear Energy Company

Docket No. 50-245

Draft Report

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

November 1982

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ABSTRACT

The Systematic Evaluation Program was initiated in February 1977 by the U.S. Nuclear Regulatory Commission to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) an assessment of how these plants compare with current licensing safety requirements relating to selected issues, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

This report documents the review of the Millstone Nuclear Power Station, Unit 1, operated by Northeast Nuclear Energy Company (located in Waterford, Connecticut). Millstone Nuclear Power Station, Unit 1, is one of ten plants reviewed under Phase II of this program. This report indicates how 137 topics selected for review under Phase I of the program were addressed. Equipment and procedural changes have been identified as a result of the review. It is expected that this report will be one of the bases in considering the issuance of a full-term operating license in place of the existing provisional operating license.

CONTENTS

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

ACRONYMS AND INITIALISMS

ABT	automatic bus transfer
ACRS	Advisory Committee on Reactor Safeguards
APRM	average power range monitor
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
BTP	Branch Technical Position
BWR	boiling-water reactor
CB&I	Chicago Bridge and Iron Company
CCW	closed cooling water
CFR	Code of Federal Regulations
CS	core spray
DBE	design-basis event
DER	design electrical rating
ECCS	emergency core cooling system
ESF	engineered safety feature(s)
ESWS	emergency service water system
FSAR	Final Safety Analysis Report
FTOL	full-term operating license
FWCI	feedwater coolant injection
GDC	General Design Criterion(a)
GE	General Electric Company
GTG	gas turbine generator
HEPB	high energy pipe break
IAC	instrumentation ac
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
IREP	Integrated Reliability Evaluation Program
IRM	intermediate range monitor
ISI	inservice inspection
LER	licensee event report
LOCA	loss-of-coolant accident
LPCI	low-pressure coolant injection
LWR	light-water reactor
MCC	motor control center
MCPR	minimum critical power ratio
MDC	maximum dependable capacity
MHC	mechanical-hydraulic control
MOV	motor-operated valve
MPA	multiplant action
mph	miles per hour
MSIV	main steam isolation valve
MSL	mean sea level
MWe	megawatt-electric
MWt	megawatt-thermal
NNECo	Northeast Nuclear Energy Company
NRC	U.S. Nuclear Regulatory Commission
OBE	operating-basis earthquake

ORNL	Oak Ridge National Laboratory
PMH	probable maximum hurricane
PMP	probable maximum precipitation
POL	provisional operating license
PRA	probabilistic risk assessment
psi	pounds per square inch
psig	pounds per square inch gage
PWR	pressurized-water reactor
RBCCW	reactor building closed cooling water
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	Regulatory Guide
rpm	revolutions per minute
RPS	reactor protection system
RWCU	reactor water cleanup
SALP	Systematic Assessment of Licensee Performance
SAR	safety analysis report
SEP	Systematic Evaluation Program
SER	safety evaluation report
SRP	Standard Review Plan
SSE	safe shutdown earthquake
STS	Standard Technical Specification
TMI	Three Mile Island
UHS	ultimate heat sink
USI	unresolved safety issue

SUMMARY

The Systematic Evaluation Program (SEP) was initiated by the U.S. Nuclear Regulatory Commission (NRC) to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

The review compared the as-built design with current review criteria in 137 different areas defined as "topics." The "Definition" and other information for each of these topics appear in Appendix A. During the review, 51 of the topics were deleted from consideration by the SEP because a review was being made under other programs (Unresolved Safety Issue (USI) or Three Mile Island (TMI) Action Plan Tasks), or the topic was not applicable to the plant; that is, the topic was applicable to pressurized-water reactors rather than to boiling-water reactors or the items to be reviewed under that topic did not exist at the site. The topics deleted because they were being reviewed under either the USI or TMI programs are listed in Appendix B, and the topics deleted because they did not apply to the plant are listed in Appendix C. The status of the USI and TMI tasks will be addressed in a provisional operating license conversion safety evaluation report. That report will be issued following completion of the SEP Integrated Plant Safety Assessment Report (IPSAR) and with IPSAR will be available for considering the conversion of the Millstone Unit 1 provisional operating license to a full-term operating license.

Of the original 137 topics, 86 were, therefore, reviewed for Millstone Unit 1; of these, 48 met current criteria or were acceptable on another defined basis. No modifications were made by the licensee during topic review. References for correspondence pertaining to safety evaluation reports (SERs) for each of the 86 topics appear in Appendix E.

The review of the remaining 38 topics found that certain aspects of plant design differed from current criteria. These topics were considered in the integrated assessment of the plant, which consisted of evaluating the safety significance and other factors of the identified differences from current design criteria to arrive at decisions on whether backfitting was necessary from an overall plant safety viewpoint. To arrive at these decisions, engineering judgment was used as well as the results of a limited probabilistic risk assessment study. This study and staff comments are in Appendix D.

Table 4.1 summarizes the staff's backfitting positions reached in the integrated assessment. In general, backfit requirements fell into one or more of the following categories: (1) equipment modification or addition, (2) procedure development or Technical Specification changes, (3) refined engineering analysis or continuation of ongoing evaluation, and (4) no backfit modifications necessary. For these categories, 6 topics primarily require equipment modification or addition; 12 topics primarily require procedure development or

changes; and 18 topics primarily require refined engineering analysis or continuation of an ongoing evaluation. Seven topics do not require any backfitting. Several topics had issues that fell into one or more of the above categories.

Safety improvements are being planned as a result of the integrated assessment and are listed below. Some safety improvements have already been implemented by the licensee. These are discussed in Section 4 but are not listed below. The following descriptions summarize the backfit actions addressed by the integrated assessment. The sections in this report relating to the issue are given in parentheses.

SAFETY IMPROVEMENTS AGREED TO AND TO BE IMPLEMENTED BY THE LICENSEE AS A RESULT OF SEP

These improvements fall into three categories. The first category comprises hardware modifications or additions that the licensee has agreed to make and that are required by the NRC. The second category comprises procedural or Technical Specification changes that become part of the operating license. The third category comprises additional engineering analysis followed by corrective measures where required. These three categories are listed below, and the issues are discussed in sections of this report given in parentheses.

Category 1, Equipment Modifications or Additions Required by NRC

(1) Provide protection against tornado missiles of systems and components required to ensure the capability to safely shut down the plant (4.7).

(2) Install an independent pressure interlock for the reactor water cleanup system inboard suction isolation valve (4.18).

(3) Install administratively controlled mechanical locking devices in specified containment isolation valves (4.20.1).

(4) Provide adequate isolation between the reactor protection system (RPS) and its power supply (4.25.2).

(5) Bypass gas turbine generator (GTG) light-off speed and generator excitation speed trips under accident conditions (4.28.1).

(6) Bypass GTG high lube oil temperature trip under accident conditions (4.28.2).

(7) Bypass gas turbine electrical generator specified trips under accident conditions (4.28.4).

(8) Install specified battery status alarms (4.30).

Category 2, Technical Specification Changes and Procedure Development

The staff's position regarding Technical Specification changes is that the proposed Technical Specification changes may be submitted all together following the completion of the integrated assessment. The licensee should submit within 90 days after the issuance of the Final Integrated Plant Safety Assessment

Report a request for an amendment of the operating license to change the facility Technical Specifications.

(1) Revise the flood emergency procedures to address the topic concerns and implement the revised procedures (4.1.6).

(2) Revise procedures to include inspection of floodwalls and floodgates (4.6.2).

(3) Develop and submit an improved inspection program for water control structures (4.6.3).

(4) Inspect turbine and propose inspection frequency based on results (4.8).

(5) Review and implement emergency procedures, including steps to proceed to cold shutdown condition from outside the control room (4.17).

(6) Revise Technical Specifications to incorporate Regulatory Guide 1.56 limits for chlorides (4.19.1).

(7) Develop procedures for the isolation of the specified containment isolation remote manual valves (4.20.3).

(8) Develop and implement procedures to protect Class 1E systems from a degraded grid voltage condition (4.27).

(9) Revise Technical Specifications to require battery service discharge tests (4.29).

Category 3, Additional Engineering Evaluation

It is the staff's position regarding additional engineering evaluation that all evaluations and corresponding backfits and schedule for backfit implementations be submitted within the established schedules, as documented in the appropriate report sections and summarized in Table 4.1. These evaluations are as follows:

(1) Determine the effects of probable maximum hurricane (PMH) wave inleakage and identify any necessary corrective actions (4.1.1).

(2) Provide analysis of PMH wave structural effects (4.1.1).

(3) Identify measures needed to protect against the effects of a PMH surge flooding of the intake structure (4.1.2).

(4) Determine the adequacy of roofs subjected to ponding resulting from the local probable maximum precipitation (PMP) (4.1.7).

(5) Evaluate the structural capability of the piles supporting the turbine building (4.2.1).

(6) Evaluate the structural capability of the piles supporting the GTG (4.2.2).

(7) Conduct soil investigation in the area of the safety-related water pipelines where they may be underlain by peat (4.2.3).

(8) Perform a volumetric inspection of all Class 1 and 2 piping, pumps, and valves and Class 2 vessels not volumetrically inspected previously. Document in Final Safety Analysis Report (FSAR) update (4.3.1).

(9) Identify and replace, if necessary, the components that do not meet fracture toughness requirements. Document in FSAR update (4.3.2).

(10) Evaluate the design of Class 1, 2, and 3 valves on a sampling basis, upgrade if necessary. Document in FSAR update (4.3.3).

(11) Analyze the design safety margins of the specified pumps. Document in FSAR update (4.3.4).

(12) Evaluate the design of the specified tanks. Document in FSAR update (4.3.5).

(13) Provide an analysis of the reactor building steel structures above the operating floor to resist tornado loads if capacities differ from those calculated by the staff, and propose corrective actions, if necessary (4.4.1).

(14) Submit analyses demonstrating capability to achieve and maintain safe shutdown of Units 1 and 2 in case of a tornado-induced failure of the stack (4.4.2).

(15) Determine the effects of failure of nonqualified structures and identify any corrective actions that may be necessary (4.4.3).

(16) Determine the adequacy of the components not enclosed in qualified structures and identify any corrective actions that may be necessary (4.4.4).

(17) Determine the adequacy of roofs of Category I structures (4.4.5).

(18) Demonstrate that wind loads were properly combined with other specified loads or identify any necessary corrective action (4.4.6).

(19) Demonstrate the appropriate consideration of groundwater hydrostatic forces on a sampling basis (4.5.2).

(20) Evaluate the improvement in turbine control valve availability associated with full-closure testing and feasibility of conducting such tests (4.8).

(21) Submit an analysis of cascading pipe breaks inside containment (4.9.1).

(22) Provide specified information about the jet impingment model used in the analysis of pipe breaks inside containment (4.9.2).

(23) Provide an analysis of the potential for and consequences of pipes whipping into the drywell liner (4.9.3).

(24) Submit a review of the specified jet impingement analysis of pipe breaks outside containment (4.10.2).

(25) Provide a plan to implement the results of the SEP Owners Group Qualification of Cable Trays Program (4.11.6).

(26) Evaluate the adequacy of original design criteria on a sampling basis for specified structural elements and the adequacy of existing structures to resist new loads and load combinations; provide information requested in Topics II-3.B, II-4.F, III-2, III-3.A, and III-6 that has been deferred to Topic III-7.B (4.12).

(27) Demonstrate proper setting of thermal-overload trip setpoints of specified motor-operated valves and discuss operating experience of those valves (4.14).

(28) Evaluate the sensitivity of the leakage detection systems in conjunction with Topic III-5.A (4.16.1).

(29) Incorporate Regulatory Guide 1.56 conductivity limits or provide justification for not doing so (4.19.1).

(30) Incorporate in the Technical Specifications procedural requirement for maintaining a minimum reserve capacity of the reactor water cleanup system demineralizers or provide justification for not doing so (4.19.2).

(31) Demonstrate that leakage detection exists in systems containing specified remote manual conainment isolation valves and that the operating stations are located in accessible areas (4.20.3)

(32) Review isolation capability of two lines and implement modifications if necessary (4.20.7).

(33) Demonstrate that the space coolers in the core spray system and low-pressure coolant injection system pump rooms are not essential (4.21.1).

(34) Evaluate the existing automatic bus transfers and identify corrective actions to ensure that faulted loads would not be transferred (4.23.1).

(35) Install appropriate interlocks in the specified manual bus transfers or provide justification for not doing so (4.23.2).

(36) Conduct test to determine if existing isolation between specified safety and control systems is adequate; propose corrective actions if necessary (4.25.1).

(37) Revise Technical Specifications to reduce battery outage limits or provide justification for not doing so (4.30).

(38) Demonstrate that the equipment serviced by specified ventilation systems is unaffected by the lack of ventilation resulting from a loss-of-offsite-power event and that the hydrogen combustion limit in the battery rooms will not be reached (4.32.2).

(39) Provide information on the space coolers for the feedwater coolant injection and diesel generator areas (4.32.3).

(40) Demonstrate that sufficient ventilation can be provided to the equipment in the intake structure in a timely manner in case of a loss-of-offsite-power event (4.32.4).

SAFETY IMPROVEMENTS REQUIRED BY THE STAFF AND TO WHICH THE LICENSEE DOES NOT AGREE

The staff has determined that the following improvements or analyses are required, but the licensee has either not responded to or specifically disagrees with the staff position. These issues are identified below and are discussed in the sections of the report given in parentheses.

(1) Demonstrate the structural integrity of valves in small piping subjected to seismic loads (4.11.2).

(2) Provide an analysis of the recirculation pump snubber supports (4.11.7).

(3) Provide a seismic analysis of the reactor vessel internals (4.11.8).

(4) Provide at least one leakage detection method that is qualified to a safe shutdown earthquake and is testable during operation (4.16.1).

(5) Install a second valve and administratively controlled mechanical locking devices on both, on specified lines penetrating the containment (4.20.2).

(6) Increase the surveillance frequency of specified reactor protection system (RPS) channels (4.24.1).

(7) Revise Technical Specifications to meet the Standard Technical Specifications requirements for RPS channel functional test frequency (4.24.2).

(8) Implement a preventive maintenance program of the GTG if none exists, improve the existing one, or provide justification for not doing so (4.28.3).

(9) Implement the BWR Standard Technical Specifications limit for primary coolant activity (4.35, 4.36).

TOPIC SAFETY EVALUATION REPORTS

Copies of this report and the associated safety evaluation reports for the 86 topics listed in Appendix E are available for public inspection at the NRC Public Document Room, 1717 H Street, N.W., Washington, D.C. 20555 and at the Waterford Public Library, Rope Ferry Road, Route 156, Waterford, Connecticut 06385. Copies of this report are also available for purchase from sources indicated on the inside front cover.

The review of the 86 topics was performed by the NRC staff and contractors listed in Appendix G. The members of the Integrated Assessment Team performing the integrated assessment of the 38 topics that did not meet current criteria are as follows.

D. Persinko--Project Manager, Integrated Assessment, Millstone Unit 1
J. Villadoniga--Nuclear Engineer, Spanish assignee to NRC/SEPB
J. J. Shea--Project Manager, Millstone Unit 1
M. Rubin--Risk Assessment Analyst
J. Shedlosky--Senior Resident Inspector, Millstone Unit 1

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INTEGRATED PLANT SAFETY ASSESSMENT
SYSTEMATIC EVALUATION PROGRAM
MILLSTONE NUCLEAR GENERATING STATION, UNIT 1

1 INTRODUCTION

1.1 Background

In the late 1960s and early 1970s, the U.S. Atomic Energy Commission's (now Nuclear Regulatory Commission) scope of review of proposed power reactor designs was evolving and somewhat less defined than it is today. The requirements for acceptability evolved as new facilities were reviewed. In 1967, the Commission published for comment and interim use proposed General Design Criteria for Nuclear Power Plants (GDC) that established minimum requirements for the principal design standards. The GDC were formally adopted, though somewhat modified, in 1971, and have been used as guidance in reviewing new plant applications since then. Safety guides issued in 1970 became part of the Regulatory Guide Series in 1972. These guides describe methods acceptable to the staff for implementing specific portions of the regulations, including certain GDC, and formalize staff techniques for performing a facility review. In 1972, the Commission distributed for information and comment a proposed "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," now Regulatory Guide 1.70. It provided a standard format for these reports and identified the principal information needed by the staff for its review. The Standard Review Plan (SRP, NUREG-75/087) was published in December 1975 and updated in July 1981 (NUREG-0800) to provide further guidance for improving the quality and uniformity of staff reviews, to enhance communication and understanding of the review process by interested members of the public and nuclear power industry, and to stabilize the licensing process. For the most part, the detailed acceptance criteria prescribed in the SRP are not new; rather they are methods of review that, in many cases, were not previously published in any regulatory document.

Because of the evolutionary nature of the licensing requirements discussed above and the developments in technology over the years, operating nuclear power plants embody a broad spectrum of design features and requirements depending on when the plant was constructed, who was the manufacturer, and when the plant was licensed for operation. The amount of documentation that defines these safety-design characteristics also has changed with the age of the plant--the older the plant, the less documentation and potentially the greater the difference from current licensing criteria.

Although the earlier safety evaluations of operating facilities did not address many of the topics discussed in current safety evaluations, all operating facilities have been reviewed more recently against a substantial number of major safety issues that have evolved since the operating license was issued. Conclusions of overall adequacy with respect to these major issues (e.g., emergency core cooling system, fuel design, and pressure vessel design) are a matter of record. On the other hand, a number of other issues (e.g., seismic considerations, tornado and turbine missiles, flood protection, pipe break effects inside containment, and piping whip) have not been reviewed against today's acceptance criteria for many operating plants, and documentation for them is incomplete.

1.2 Systematic Evaluation Program Objectives

The Systematic Evaluation Program (SEP) was initiated by the U.S. Nuclear Regulatory Commission (NRC) in 1977 to review the designs of older operating nuclear reactor plants in order to reconfirm and document their safety. The review provides (1) an assessment of the significance of differences between current technical positions on safety issues and those that existed when a particular plant was licensed, (2) a basis for decidi , on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

The original SEP objectives were:

(1) The program should establish documentation tha' shows how the criteria for each operating plant reviewed compare with current criteria on significant safety issues, and should provide a rationale for acceptable departures from these criteria.

(2) The program should provide the capability to make integrated and balanced decisions with respect to any required backfitting.

(3) The program should be structured for early identification and resolution of any significant deficiencies.

(4) The program should assess the safety adequacy of the design and operation of currently licensed nuclear power plants.

(5) The program should use available resources efficiently and minimize requirements for additional resources by NRC or industry.

The program objectives were later interpreted to ensure that the SEP also provides safety assessments adequate for conversion of provisional operating licenses (POLs) to full-term operating licenses (FTOLs). The final version of this report and a POL conversion safety evaluation report that will address the status of all applicable generic activities (TMI and USI), including those that formed the basis for deletion of specific SEP topics, will form a part of the basis for the Commission's consideration of the license conversion.

Many of the plants selected for review were licensed before a comprehensive set of licensing criteria had been developed. They include five of the oldest nuclear reactor plants and seven plants under NRC review for the conversion of POLs to FTOLs. The pla ts to be considered under the original Phase II program were

(1) Yankee Rowe (FTOL PWR)
(2) Haddam Neck (FTOL PWR)
(3) Millstone 1 (POL BWR)
(4) Oyster Creek (POL BWR)
(5) Ginna (POL PWR)
(6) LaCrosse (POL BWR)

(7) Big Rock Point (FTOL BWR)
(8) Palisades (POL PWR)
(9) Dresden 1 (FTOL BWR)
(10) Dresden 2 (POL BWR)
(11) San Onofre (POL PWR)

The SEP review of Dresden Unit 1 has been deferred because the plant is undergoing an extensive modification and is not scheduled for restart before June 1986. Therefore, the total number of plants being reviewed for Phase II is 10.

1.3 Description of Plant

The Millstone Nuclear Generating Station, Unit 1, located in New London County, Connecticut, is a boiling-water reactor (BWR) designed by General Electric. The licensee is the Northeast Nuclear Energy Company (NNECo). NNECo filed the application for a construction permit and operating license in November 1965. The construction permit was issued in May 1966. The initial submittal of the Final Safety Analysis Report was filed in March 1968, and the initial provisional operating license was issued on October 26, 1970. On September 1, 1972 the licensee applied for a full-term operating license. The licensed thermal power rating currently is 2,011 megawatts-thermal (MWt). The Millstone Unit 1 primary coolant system consists of the reactor vessel, recirculation system, main steam system, and isolation condenser. A diagram of the major components of the primary coolant system is provided in Figure 1.1.

The reactor is a single-cycle, forced-circulation, boiling-water reactor producing steam for direct use in the steam turbine. The reactor vessel contains internal components, which include the necessary equipment for separating steam and water flow paths.

The recirculation system provides for forced flow through the reactor core to facilitate heat removal capability. The system consists of 2 external loops with motor-driven centrifugal pumps and 20 jet pumps located in the reactor pressure vessel. Water that is separated from the steam in the reactor vessel mixes with water provided by the feedwater system, is drawn from outside the core, passes through the recirculation pumps, and is discharged back into the reactor below the core area at high velocity through the jet pumps. The action of the jet pumps mixes the high velocity water with water in the reactor vessel, recirculating the water through the core. This serves to increase the heat removal capability of the water. The water then flows upward through the core where boiling produces a steam-water mixture.

The main steam system directs the steam generated in the reactor vessel to the turbine generator for conversion to electrical power. The steam-water mixture travels from the reactor core, through the steam-separating equipment into the four main steam lines. The steam then passes through the main steam lines to the turbine. Included in the main steam system are the relief and safety valves, which provide overpressure protection for the reactor vessel and associated piping systems. The relief valves are also designed to rapidly depressurize the reactor vessel so that the low-presssure portion of the emergency core cooling systems will function. The reactor relief valves are located upstream of

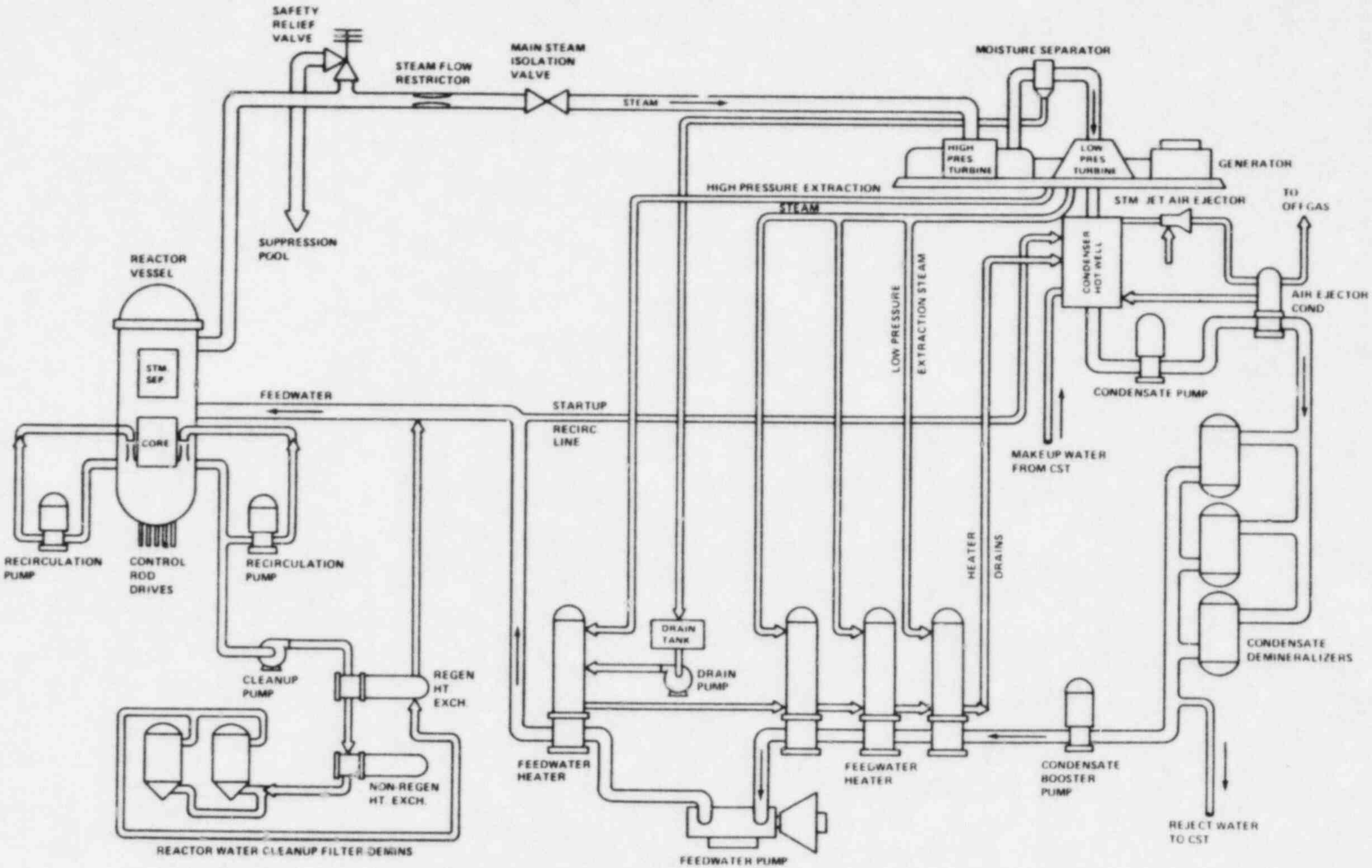

Figure 1.1 Millstone Nuclear Generating Station, Unit 1 -- primary coolant system

the first isolation valve and discharge directly to the pressure-suppression pool; the safety valves are located on the steam lines inside the primary containment and discharge to the drywell atmosphere.

The isolation condenser system will provide reactor core cooling if the reactor should become isolated from the main condenser because of closure of the main steam isolation valves. The isolation condenser operates by natural circulation. During operation steam flows from the reactor, condenses in the tubes of the isolation condenser, and flows back to the reactor by gravity.

The containment systems provide a multibarrier pressure-suppression containment composed of a primary containment, the pressure-suppression system, and a secondary containment, the reactor building.

The primary containment system is designed to (1) provide a barrier that will control the release of fission products to the secondary containment and (2) rapidly reduce the pressure in the containment resulting from a loss-of-coolant accident. The system consists of a drywell, which houses the reactor vessel and recirculation loops; the pressure-suppression pool, which contains the large volume of water used to condense the accident steam release; and the connecting vent systems. The drywell, which is in the shape of a light bulb and is constructed of steel plate, varies in diameter from 34 ft 2 in. to 64 ft; the spherical section is approximately 64 ft high, and overall the drywell is approximately 100 ft high. The shell thickness varies from approximately 11/16 to 2-3/4 in. The pressure-suppression chamber is a steel pressure vessel in the shape of a torus with an inside diameter of 29 ft 6 in., a water volume of approximately 91,000 cubic feet, and an air volume of approximately 117,000 cubic feet.

The reactor building is designed to provide containment during reactor refueling and maintenance operations when the primary containment system is open. The building will also provide secondary containment when the primary containment is required to be in service. The reactor building consists of the monolithic reinforced concrete floors and walls enclosing the nuclear reactor, primary containment, and reactor auxiliaries, and the building superstructure, which consists of concrete walls and builtup roof decking.

1.4 Summary of Operating History and Experience

The Millstone Unit 1 plant received a provisional operating license on October 26, 1970, achieved initial criticality on the same date, and began commercial operation in December 1970. The reactor has a licensed thermal power of 2,011 MWt and a design electric rating of 660 megawatts-electric (MWe).

1.4.1 Summary of Oak Ridge National Laboratory Report

1.4.1.1 Introduction

From 1971 through 1981, the reactor availability factor at Millstone Unit 1 averaged 76.1% and the unit capacity factor averaged 61.6%. The cumulative values were 77.1% and 64.4%, respectively, both of which are above average for commercial nuclear power plants. The reactor availability factor fell below 70% in only 2 years, 1973 and 1981. The major unit shutdowns in 1973 were for refueling and for feedwater sparger replacement. These two shutdowns combined for over 5 months of downtime. In 1981, two shutdowns, for refueling and for balancing of the turbine, again combined for over 5 months of downtime.

The operating history review focused on data evaluation that was divided into two segments: (1) evaluation of forced shutdowns and power reductions and (2) evaluation of reportable events. Design-basis events (DBEs), which are defined in the NRC's Standard Review Plan (NUREG-0800), are failures that initiate system transients and challenge engineered safety features. In the forced shutdown and power reduction segment, the review identified DBEs and recurring events that might indicate a potential operating concern. In the reportable event segment, which included environmental events and radiological release events, the review identified significant events and recurring events that might indicate a potential operating concern. Significant events were either DBEs or events with a loss of engineered safety function.

1.4.1.2 Forced Shutdowns and Power Reductions

Of the 172 forced shutdowns and power reductions between 1971 and 1981 at Millstone, 55 were DBEs of 1 of the 12 following types:

(1) turbine trip (33)
(2) steam pressure regulator failure resulting in increased steam flow (3)
(3) steam pressure regulator failure resulting in decreased steam flow (3)
(4) loss of normal feedwater (3)
(5) inadvertent opening of a safety or relief valve (3)
(6) increased feedwater flow (2)
(7) loss of external electric load (2)
(8) inadvertent closure of main steam isolation valve (MSIV) (2)
(9) decreased feedwater temperature (1)
(10) loss of condenser vacuum (1)
(11) reactor recirculation pump trip (1)
(12) recirculation controller malfunction resulting in decreased recirculation flow (1)

Of the 55 DBEs, 47 were the result of equipment failure. Human error caused the remaining eight events. In all DBEs, the engineered safety features operated properly to mitigate the transient.

DBEs averaged five occurrences per year over the operating history at Millstone Unit 1. The largest number of events in a single year (25) occurred in 1971. Since 1977, the average number of DBEs per year has been about three. The frequency of occurrence of each type of DBE is consistent with the experience of other plants except for turbine trips. The primary cause of turbine trips (21 of 33 events) was problems with moisture separator drain tank level control during power changes. The level control problem occurred less frequently over time causing 14 events in 1971 and 1 event in 1981.

1.4.1.3 Reportable Events

In the reportable event segment of the operating history review of Millstone Unit 1, 320 events were reviewed. The trend for the number of reportable event reports submitted by Millstone Unit 1 is generally upward; the peak years are 1977, 1979, and 1981, with 38, 36, and 44 events, respectively. The causes of reportable events have been primarily inherent equipment failures, which contributed to 55% of all reported events. Human error (including administrative, design, fabrication, installation, maintenance, and operator error) caused 44% of the reported events. Other causes, such as adverse environmental conditions, were responsible for the remaining 1%. There is no apparent trend in the causes of reported events.

Of the 320 reported events, 13 are considered significant:

(1) loss of emergency power (6)
(2) loss of emergency core cooling system (1)
(3) turbine bypass valve failed open (1)
(4) failure of control rod drive accumulators (1)
(5) failure of the isolation condenser (1)
(6) hydrogen explosion (1)
(7) unplanned criticality (1)
(8) recirculation pumps trip without alarm (1)

The major contributor to the significant events was human error, which caused 10 of the 13 events. The remaining three events were caused by equipment failures of diesel generator components. All but three of the significant events have occurred since 1976.

Failure of the emergency power system was a major cause of significant events. On two occasions in 1976, the gas turbine generator failed when the isolation condenser was inoperable. The gas turbine is one of two emergency power supplies at Millstone Unit 1. In the event of a loss of offsite power, the feedwater coolant injection system and one loop of the low-pressure coolant injection and core spray systems would have been lost in addition to the isolation condenser (letters, Mar. 22, 1976 and Mar. 29, 1976). During a loss of offsite power in 1976, the gas turbine again failed to run. The unit's diesel generator was the sole source of ac power (letter, Aug. 24, 1976). On December 1, 1977, both emergency power sources were lost simultaneously (letter, Dec. 12, 1977). Two potential emergency power system failures were discovered during design reviews in 1979 and 1981. The possibility existed to lose emergency power to emergency cooling systems by either the failure to sense a power loss or a single relay failure disabling both the gas turbine and diesel generators (letters, Sept. 27, 1979 and Apr. 20, 1981).

1.4.1.4 Recurring Events

The following five types of recurring events were noted during the two segments of the operating history review:

(1) partial loss of emergency power
(2) excessive cooldowns
(3) pipe cracks
(4) isolation condenser valve failures
(5) MSIV failures

The emergency power system at Millstone Unit 1 consists of one diesel generator and one gas turbine generator. If normal power to the plant is lost, the gas turbine is the sole power source for the feedwater coolant injection (FWCI) system. The gas turbine generator failed to start or run for its entire mission 24 times. As discussed earlier, many of these failures occurred when redundant power systems or systems redundant to the FWCI system were not operable.

Millstone Unit 1 experienced five excessive thermal transients in eight blowdowns because of safety and relief valve failures. The cooldown rates during the transients ranged from 105°F/hr to 450°F/hr. The first of these events occurred in 1971. Since 1975, the transients have recurred at a rate greater than one every 2 years and continue to be an ongoing problem.

Millstone Unit 1 reported eight instances of pipe cracks. Cracks appeared in feedwater spargers, head spray piping, main steam line supports, and condenser nozzles. Pipe cracking found at Millstone is typical of the generic problems found in many BWRs.

A variety of problems caused nine isolation condenser failures between 1970 and 1979. In seven of the nine events, a supply valve opened too wide, or failed to open, and caused an isolation condenser system failure. On one occasion, a valve transferred open and initiated the isolation condenser system. The final event occurred because a return valve failed to close. The problems with the isolation condenser valves appear to have been solved, since the last reported occurrence was September 4, 1979.

There were 10 failures of the main steam isolation valves (MSIVs). The causes for MSIV failures were either (1) poor quality control air to the pilot valves or (2) binding of MSIV stems with valve stem packing. These failure mechanisms have the potential to affect more than one MSIV at a time and continued to occur despite corrective actions.

1.4.2 Operating Experience, January 1 Through November 1, 1982

The unit operated through September 11, having experienced three reactor trips during 1982. The eighth refueling outage started on September 11, 1982. Gross electrical generation has been restricted to approximately 625 MWe from the normal 684 MWe since June 1981 when the turbine fourteenth (L-1) stages were removed. Capacity and service factors, computed for the year through September, are 79.5% and 91.2%, respectively. Cumulative capacity and service factors for the life of the unit are 62.8% and 71.9%, respectively.

Three reactor trips occurred on February 11, April 13, and July 31, 1982. The first was due to the occurrence of low reactor water level when a feedwater regulating valve air operator failed at 90% power. The second, a manual scram, followed spurious actuation of the anticipated transient without scram (ATWS) system and the opening of recirculation pump motor-generator field breakers. DC power was secured to an ATWS division during ground isolation procedures. The third trip again resulted from spurious actuation of the ATWS system; its power supplies shut down simultaneously when the dc supply line reached an overvoltage setpoint. This occurred during a voltage transient resulting from a full-load reject.

Major evolutions being accomplished during the present refueling outage include (1) the outstanding torus structural modifications, (2) replacement of the turbine fourteenth (L-1) stage discs and buckets, (3) replacement of a section of isolation condenser steam supply piping found with a crack in a weld-heat-affected zone, (4) installation of a clamp because cracks were found in a core spray sparger at a junction box, (5) replacement of the scram discharge volume instrument volume with two redesigned instrument volumes, (6) replacement of jet pump beams because of cracking, and (7) replacement of safety-related GE-type HFA relays following the discovery of a potentially generic common-mode failure resulting from melting Lexan coil spools.

1.4.2.1 Regulatory Performance, January 1 Through November 1, 1982

A management meeting was held with the licensee on November 3, 1982 to discuss the findings of the NRC Systematic Assessment of Licensee Performance (SALP), which was conducted in accordance with NRC Manual Chapter 0516. The review included the licensee's performance with the objective of improving regulatory programs and performance and was based on activities from September 1, 1981 through August 31, 1982. The SALP Board concluded that the licensee's operational and regulatory performance was generally acceptable and directed toward safe operation.

The SALP Board's conclusions for each of nine functional areas were categorized as follows:

Category 1

Reduced NRC attention may be appropriate. The attention and involvement of the licensee's management are aggressive and oriented toward nuclear safety; the licensee's resources are ample and effectively used so that a high level of performance with respect to operational safety or construction is being achieved.

Category 2

NRC attention should be maintained at normal levels. The attention and involvement of the licensee's management are evident and are directed toward nuclear safety; the licensee's resources are adequate and are reasonably effective so that satisfactory performance with respect to operational safety or construction is being achieved.

Category 3

Both NRC and licensee attention should be increased. The attention and involvement of the licensee's management are acceptable and are directed toward nuclear safety, but weaknesses are evident; the licensee's resources appeared strained or not effectively used so that minimally satisfactory performance with respect to operational safety and construction is being achieved.

The following functional areas were evaluated and found to be Category 1:

(1) plant operations
(2) radiological controls
(3) maintenance
(4) surveillance
(5) fire protection

(6) emergency preparedness
(7) security and safeguards
(8) refueling - preparation and planning
(9) licensing activities

Twenty-two events have been reported through November 1, 1982 by the licensee event report (LER) system. Of these, 15 were due to component failure, 2 to personnel errors, and 1 to design. Both of the LERs resulting from personnel errors were concerned with inoperable plant vent stack radiation monitor or monitor recorders.

A potentially generic common-mode failure in General Electric-type HFA relays resulting from melting coil spools was reported. Two-stage Target Rock safety/relief valves failed to open at 103% of set pressure when pressure was increased on a slow ramp. Cracking was found at one core spray sparger junction box. Problems with the gas turbine generator were reported in three LERs, and set-point drift was reported in four LERs.

2 REVIEW METHOD

2.1 Overview

The Systematic Evaluation Program (SEP) review procedure represents a departure from the typical NRC staff reviews conducted to support the granting of a construction permit or operating license for a new facility or a license amendment for an operating facility. A typical licensing review starts with the submittal by the utility of a safety analysis report (SAR) that describes the design of the proposed plant. The staff reviews the SAR on the basis of the Standard Review Plan (SRP), Regulatory Guides, and Branch Technical Positions (found in the SRP) that constitute current licensing criteria. The guidelines in the SRP represent acceptable means of complying with licensing regulations specified in Title 10 of the Code of Federal Regulations (10 CFR).

The SEP was initiated by NRC, and not by the licensee as part of an application for a license or request for a license amendment. The SEP procedure involves several phases of data gathering and evaluation so that an integrated assessment of the overall plant safety can be made. The various phases and their interrelationships are described below.

2.2 Selection of Topic List

A list of significant safety topics was derived from existing safety issues during Phase I of the program. More than 800 items were considered in the development of the original list; however, a number of these were found to be duplicative in nature or were deleted for other reasons. Categories of topics that were deleted for other reasons are (1) those not normally included in the review of light-water reactors, (2) those related either to research-and-development programs or to the development of analytical evaluation models and methodology, and (3) those that are reviewed on a periodic basis in accordance with current criteria (for example, fuel performance). The topics retained numbered 137; these were arranged in groups corresponding to the organization of the SRP. A "definition" was prepared for each topic to ensure a common understanding. This definition plus a statement of the safety objective for the review and the status of the review at that time is contained in Appendix A for ease of reference.

During the course of this review, the number of topics that applied to all plants was reduced further because some topics were being reviewed generically under either the Unresolved Safety Issues (USIs) program or the Three Mile Island (TMI) NRC Action Plan; also, duplicates found within the SEP topics were deleted. Appendix B shows these topics along with the corresponding USI, TMI task, or SEP topic referenced. The basis for deletion appears in Appendix A under the individual topics. The current status of USI and TMI Action Plan Item reviews applicable to SEP will be discussed in a POL conversion safety evaluation report that will be issued following completion of the integrated assessment.

Plant-specific deletions other than those common to all SEP plants were made to account for nonapplicability of particular topics to Millstone Unit 1. The plant-specific topics that were removed for Millstone Unit 1 and the basis for deletion are shown in Appendix C.

For Millstone Unit 1, this process resulted in 86 topics from the topic list that formed the SEP review. The final list of 86 topics that were reviewed appears in Section 3.1.

The milestones in the review of the SEP program and the Millstone Unit 1 plant are shown in Table 2.1.

2.3 Topic Evaluation Procedures

Each SEP topic in Section 3.1 was reviewed to determine whether the corresponding plant design was consistent with current licensing criteria such as regulations, guides, and SRP review criteria, or the equivalent of such criteria. Safety evaluation reports (SERs) for all 86 topics were issued to document the comparison with current licensing criteria and to identify potential areas for backfitting. References for letters regarding the individual topic SERs are contained in Appendix E. These documents describe the detailed evaluations where conclusions are summarized in this report.

Topics were evaluated by one of two methods:

(1) The NRC staff reviewed and formally issued an SER to the licensee. This SER was termed a draft because it was only one input element to the evaluation. The purpose of the draft SER was to verify the factual accuracy of the described facility and to allow the licensee to identify possible alternate approaches to meeting the current licensing criteria. After a review of the licensee's comments on the draft SER, factual changes were incorporated as needed, proposed alternatives were reviewed, and the SER was issued in final form.

(2) The licensee submitted a safety analysis report and the staff issued a final SER based on a review of this submittal.

After completion of the topic evaluation, the disposition of each topic was grouped according to one of the following results:

(1) The plant is consistent with current licensing criteria and the topic review is considered complete. If the plant does not meet current licensing criteria, but the present design is equivalent to current criteria, the topic is also considered complete. A justification for this conclusion is provided in the topic SER. The topics in this category are identified in Section 3.1 of this report by an asterisk.

(2) The plant is not consistent with current licensing criteria, but the licensee has implemented design or procedural changes that the staff finds acceptable. Although the licensee committed to certain design or procedural changes during the course of the topic reviews for Millstone Unit 1, none were actually implemented; therefore, the differences were not considered resolved in the topic review. None of the topics fell into this category.

Table 2.1 Topic list selection and resolution

ORIGINAL PHASE I TOPIC LIST
800

Many of these topics were deleted because they were duplicative in nature, were not normally included in the review of light-water reactors, were related to research-and-development programs, or were reviewed on a periodic basis in accordance with current criteria.

FINAL LIST OF PHASE I TOPICS REVIEWED DURING PHASE II
137 (see Appendix A)

Of the 137 topics, 20 were deleted because they were being reviewed generically under either the Unresolved Safety Issues (USIs) program or the Three Mile Island (TMI) NRC Action Plan (see Appendix B).

REMAINING TOPICS AFTER DELETION OF USIs AND TMI-RELATED TOPICS
117

Of the remaining 117 topics, 31 were deleted because the topics did not apply to Millstone Unit 1 (see Appendix C).

FINAL NUMBER OF TOPICS REVIEWED FOR MILLSTONE UNIT 1
86 (see Section 3.1 and Appendix E)

TOPICS THAT MET CURRENT CRITERIA OR WERE ACCEPTABLE ON ANOTHER DEFINED BASIS
48 (see Section 3.1)

TOPICS THAT MET CURRENT CRITERIA OR WERE ACCEPTABLE ON ANOTHER DEFINED BASIS AFTER MODIFICATIONS MADE DURING TOPIC REVIEW
0

TOPICS CONSIDERED FOR BACKFIT IN THE INTEGRATED ASSESSMENT
38 (see Table 4.1 and Sections 4.1-4.36)

(3) The plant is not consistent with current licensing criteria, and the differences from these criteria are to be evaluated as potential candidates for backfitting. If the staff determines the difference is of immediate safety significance, action is taken to resolve the issue promptly. No issues at Millstone Unit 1 required that prompt action be taken. If the difference is not of immediate safety significance, the resolution is deferred to the integrated plant safety assessment to obtain maximum benefit from coordinated and integrated backfitting decisions. The SEP evaluation of all 86 topics led to the conclusion that 38 topics were not consistent with current licensing criteria. All of these topics were considered in the integrated safety assessment and appear in Section 4.

2.4 Integrated Plant Safety Assessment

The objective of the integrated plant safety assessment is to make balanced and integrated decisions on backfitting current licensing criteria to SEP facilities. Factors considered important in reaching decisions on backfitting include safety significance, radiation exposure to workers, and, to a lesser extent, implementation impact and schedule.

A meeting was held with the licensee to discuss these factors as they related to the differences identified during the SEP review between actual facility design and current licensing criteria and to obtain the licensee's views on safety significance and possible corrective actions.

These factors were considered in reaching a decision on backfitting and are discussed in Section 4 for each identified difference between actual facility design and current licensing criteria. Because these factors sometimes rely on judgment, risk assessment techniques were used to the extent possible to supplement the staff's judgments concerning safety significance. The probabilistic risk assessment (PRA) performed by Sandia National Laboratories, along with comments by the staff, appears in Appendix D. For reasons given in Appendix D, only certain topics could be readily analyzed by a PRA. Of a total number of 38 topics considered in the integrated assessment, 20 were evaluated assisted by PRA techniques.

3 TOPIC EVALUATION SUMMARY

3.1 Final Millstone Unit 1-Specific List of Topics Reviewed

Listed below are the 86 topics that were reviewed for Millstone Unit 1. The topics with asterisks are those for which the plant meets current criteria or was acceptable on another defined basis:

TOPIC	TITLE
II-1.A*	Exclusion Area Authority and Control
II-1.B*	Population Distribution
II-1.C*	Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities
II-2.A*	Severe Weather Phenomena
II-2.C*	Atmospheric Transport and Diffusion Characteristics for Accident Analysis
II-3.A*	Hydrologic Description
II-3.B	Flooding Potential and Protection Requirements
II-3.B.1	Capability of Operating Plant To Cope With Design-Basis Flooding Conditions
II-3.C	Safety-Related Water Supply (Ultimate Heat Sink (UHS))
II-4*	Geology and Seismology
II-4.A*	Tectonic Province
II-4.B*	Proximity of Capable Tectonic Structures in Plant Vicinity
II-4.C*	Historical Seismicity Within 200 Miles of Plant
II-4.D*	Stability of Slopes
II-4.F	Settlement of Foundations and Buried Equipment
III-1	Classification of Structures, Components, and Systems (Seismic and Quality)
III-2	Wind and Tornado Loadings
III-3.A	Effects of High Water Level on Structures

TOPIC	TITLE
III-3.C	Inservice Inspection of Water Control Structures
III-4.A	Tornado Missiles
III-4.B	Turbine Missiles
III-4.C*	Internally Generated Missiles
III-4.D*	Site-Proximity Missiles (Including Aircraft)
III-5.A	Effects of Pipe Break on Structures, Systems, and Components Inside Containment
III-5.B	Pipe Break Outside Containment
III-6	Seismic Design Considerations
III-7.B	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria
III-7.D*	Containment Structural Integrity Tests
III-8.A	Loose-Parts Monitoring and Core Barrel Vibration Monitoring
III-8.C*	Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance
III-10.A	Thermal-Overload Protection for Motors of Motor-Operated Valves
III-10.C*	Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves
IV-1.A*	Operation With Less Than All Loops in Service
IV-2	Reactivity Control Systems Including Functional Design and Protection Against Single Failures
IV-3*	BWR Jet Pump Operating Indications
V-5	Reactor Coolant Pressure Boundary (RCPB) Leakage Detection
V-6*	Reactor Vessel Integrity
V-10.A*	Residual Heat Removal System Heat Exchanger Tube Failures
V-10.B	Residual Heat Removal System Reliability
V-11.A	Requirements for Isolation of High- and Low-Pressure Systems
V-11.B*	Residual Heat Removal System Interlock Requirements

TOPIC	TITLE
V-12.A	Water Purity of BWR Primary Coolant
VI-1*	Organic Materials and Postaccident Chemistry
VI-2.D*	Mass and Energy Release for Postulated Pipe Break Inside Containment
VI-3*	Containment Pressure and Heat Removal Capability
VI-4	Containment Isolation System
VI-6*	Containment Leak Testing
VI-7.A.3	Emergency Core Cooling System Actuation System
VI-7.A.4	Core Spray Nozzle Effectiveness
VI-7.C*	Emergency Core Cooling System (ECCS) Single-Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves
VI-7.C.1	Appendix K--Electrical Instrumentation and Control Re-Reviews
VI-7.C.2*	Failure Mode Analysis (Emergency Core Cooling System)
VI-7.D*	Long-Term Cooling Passive Failures (e.g., Flooding of Redundant Components)
VI-10.A	Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing
VI-10.B*	Shared Engineered Safety Features, Onsite Emergency Power, and Service System For Multiple-Unit Stations
VII-1.A	Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices
VII-1.B*	Trip Uncertainty and Setpoint Analysis Review of Operating Data Base
VII-2*	Engineered Safety Features System Control Logic and Design
VII-3	Systems Required for Safe Shutdown
VII-6*	Frequency Decay
VIII-1.A	Potential Equipment Failures Associated With Degraded Grid Voltage
VIII-2	Onsite Emergency Power System (Diesel Generator)
VIII-3.A	Station Battery Capacity Test Requirements

TOPIC	TITLE
VIII-3.B	DC Power System Bus Voltage Monitoring and Annunciation
VIII-4*	Electrical Penetrations of Reactor Containment
IX-1*	Fuel Storage
IX-3	Station Service and Cooling Water Systems
IX-5	Ventilation Systems
IX-6*	Fire Protection
XIII-2*	Safeguards/Industrial Security
XV-1	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve
XV-3	Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)
XV-4*	Loss of Nonemergency AC Power to the Station Auxiliaries
XV-5*	Loss of Normal Feedwater Flow
XV-7*	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break
XV-8*	Control Rod Misoperation (System Malfunction or Operator Error)
XV-9*	Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate
XV-11*	Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)
XV-13*	Spectrum of Rod Drop Accidents (BWR)
XV-14*	Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory
XV-15*	Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve
XV-16	Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment
XV-18	Radiological Consequences of Main Steam Line Failure Outside Containment

TOPIC	TITLE
XV-19*	Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary
XV-20*	Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)
XVII*	Operational Quality Assurance Program[1]

3.2 Topics for Which Plant Design Meets Current Criteria or Was Acceptable on Another Defined Basis

As listed in Section 3.1.

3.3 Topics for Which Plant Design Meets Current Criteria or Equivalent Based on Modifications Implemented by the Licensee

During the topic reviews for Millstone Unit 1, the licensee committed to certain design changes, procedural changes, or analyses to resolve differences identified. However, none of these actions were implemented; therefore, no topic was considered resolved before the integrated assessment. Consequently, all of the differences identified during the topic reviews and the commitments made by the licensee are discussed in the context of the integrated assessment in Section 4.

[1]The Operational Quality Assurance Program was reviewed according to the criteria specified for operating reactors in 1974 (see Appendix A). NRC has recently approved the licensee's Quality Assurance Program ND-QA-1, Rev. 4A, by letter dated April 9, 1982.

4 INTEGRATED ASSESSMENT SUMMARY

Table 4.1 shows the list of topics considered in the integrated assessment, whether Technical Specification requirements or backfit are needed, and whether or not the licensee proposes to backfit. The licensee's proposed corrective actions are identified in his letter dated September 22, 1982. A more detailed description of each topic with identified differences from current licensing criteria follows.

The differences from current licensing criteria identified in this section were derived from staff safety evaluation reports referenced in Appendix E.

A limited probabilistic risk assessment (PRA) has been performed for Millstone Unit 1 for 20 SEP topics with identified differences from current licensing criteria. The limited PRA was performed by using the Millstone Unit 1 PRA developed for the Interim Reliability Evaluation Program (IREP) and calculating the change in risk associated with the identified differences. Preliminary results of the Millstone Unit 1 IREP were considered in the review of individual differences, where applicable.

The draft IREP study is still undergoing NRC review. Substantial changes are not expected; however, any modifications to the IREP results will be evaluated to assess their impact on the conclusions reached in the integrated assessment.

4.1 Topic II-3.B, Flooding Potential and Protection Requirements; Topic II-3.B.1, Capability of Operating Plants To Cope With Design-Basis Flooding Conditions; Topic II-3.C, Safety-Related Water Supply (Ultimate Heat Sink (UHS))

10 CFR 50 (GDC 2), as implemented by SRP Sections 2.4.2, 2.4.5, 2.4.10, and 2.4.11 and Regulatory Guides 1.59 and 1.27, requires that structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as flooding. The safety objective of these topics (II-3.B, II-3.B.1, and II-3.C) is to verify that adequate operating procedures and/or system design are provided to cope with the design-basis flood.

The site grade elevation varies from 14.0 ft to above 15 ft mean sea level (MSL). During the staff's review of the hydrology-related topics, the following flooding elevation was identified, as defined by current licensing criteria: probable maximum hurricane (PMH) - 22.3 ft MSL (including wave action)

As a result of this flooding level and flooding from local probable maximum precipitation (PMP), the staff has identified the following issues.

4.1.1 Flooding Elevation

PMH flood level, including wave effects, results in a water level of 22.3 ft MSL (18.11 ft MSL stillwater level plus wave action). Safety-related structures are protected by concrete floodwalls to 19.0 ft MSL.

Table 4.1 Integrated assessment summary

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
II-3.B, II-3.B.1, II-3.C	4.1.1	Flooding Elevation	No	Determine the effects of probable maximum hurricane (PMH) wave inleakage and identify any necessary corrective actions.	Yes	12/82	-
			No	Provide analysis of PMH wave structural effects. (See Sections 4.6 and 4.12.)	Yes	10/83	-
	4.1.2	Intake Structure	No	Identify measures needed to protect against the effects of PMH surge flooding of the intake structure.	Yes	12/82	-
	4.1.3	Local Flooding	No	None	-	-	-
	4.1.4	Gas Turbine Building	No	None	-	-	-
	4.1.5	Diesel Fuel Oil	No	None (See Section 4.1.6.)	-	-	-
	4.1.6	Emergency Procedures	No	Revise the flood emergency procedures to address the topic concerns and implement the revised procedures.	Yes	12/82	-
	4.1.7	Roofs	No	Determine the adequacy of roofs subjected to ponding resulting from the local probable maximum precipitation (PMP). (See Section 4.12.)	Yes	10/83	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
II-4.F	4.2.1	Turbine Building	No	Evaluate structural capability of the piles supporting the building. (See Section 4.12.)	Yes	10/83	-
	4.2.2	Gas Turbine Generator Building	No	Evaluate structural capability of the piles supporting the building. (See Section 4.12.)	Yes	10/83**	-
	4.2.3	Buried Pipelines	No	Conduct soil investigation in area of the safety-related water pipelines where they may be underlain by peat. (See Section 4.12.)	Yes	10/83	-
III-1	4.3.1	Radiography Requirements	No	Perform a volumetric inspection of all Class 1 and 2 piping, pumps, and valves and Class 2 vessels not volumetrically inspected previously. Document in FSAR update.	Yes	10 CFR 50.71 e.3.ii	-
	4.3.2	Fracture Toughness	No	Identify and replace, if necessary, the components that do not meet fracture toughness requirements. Document in FSAR update.	Yes	10 CFR 50.71 e.3.ii	-
	4.3.3	Valves	No	Evaluate design of Class 1, 2, and 3 valves on a sampling basis; upgrade if necessary. Document in FSAR update.	Yes	10 CFR 50.71 e.3.ii	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-1	4.3.4	Pumps	No	Analyze the design safety margins of the specified pumps. Document in FSAR update.	Yes	10 CFR 50.71 e.3.ii	-
	4.3.5	Storage Tanks	No	Evaluate design of specified tanks. Document in FSAR update.	Yes	10 CFR 50.71 e.3.ii	-
III-2	4.4.1	Reactor Building Steel Structures Above the Operating Floor	No	Analyze the specified structures' capabilities to resist tornado loads and propose corrective actions, if necessary. (See Section 4.12.)	Yes	10/83	-
	4.4.2	Ventilation Stack	No	Submit analyses demonstrating capability to achieve and maintain safe shutdown of Units 1 and 2 in case of a tornado-induced failure of the stack.	Yes	11/82	-
	4.4.3	Effects of Failure of Nonqualified Structures	No	Provide an analysis of the effects and any corrective actions that may be necessary.	Yes	10/83	-
	4.4.4	Components Not Enclosed in Qualified Structures	No	Determine the adequacy of the components and identify any corrective actions that may be necessary.	Yes	10/83	-
	4.4.5	Roofs	No	Determine the adequacy of roofs of Category I structures. (See Section 4.12.)	Yes	10/83	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-2	4.4.6	Load Combinations	No	Demonstrate that wind loads were properly combined with other specified loads or identify any necessary corrective action. (See Section 4.12.)	Yes	10/83	-
III-3.A	4.5.1	Flood Elevation	No	Provide analysis of PMH wave structural effects and identify any necessary corrective actions. (See Sections 4.1.1 and 4.12.)	Yes	10/83	-
	4.5.2	Groundwater	No	Demonstrate appropriate consideration of hydrostatic forces on a sampling basis. (See Section 4.12.)	Yes	10/83	-
III-3.C	4.6.1	Deficiences Noted During Site Visit	No	Determine the adequacy of roofs subjected to ponding resulting from the local PMP. (See Sections 4.12 and 4.1.7.)	Yes	10/83	-
	4.6.2	Structures and Components Requiring Inspection	No	Revise procedure to include inspection of floodwalls and floodgates. (See Section 4.6.3.)	Yes	12/82	-
	4.6.3	Inspection Program	No	Develop and submit an improved inspection program for water control structures.	Yes	12/82	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-4.A	4.7	Tornado Missiles	No	Provide protection of systems and components to ensure the capability to safely shut down the plant.	Yes	-	-
III-4.B	4.8	Turbine Missiles	No	Inspect turbine and propose frequency based on results.	Yes	Next refueling outage	-
			No	Evaluate the improvement in control valve availability associated with full closure testing and feasibility of conducting such tests.	Yes	-	-
III-5.A	4.9.1	Cascading Pipe Breaks	No	Submit an analysis of cascading pipe breaks.	Yes	12/82	-
	4.9.2	Jet Impingement	No	Provide information specified.	Yes	12/82	-
	4.9.3	Pipe Whip	No	Provide an analysis of the potential for and consequences of pipes whipping into the drywell liner.	Yes	12/82	-
III-5.B	4.10.1	Moderate-Energy Piping	No	None	-	-	-
	4.10.2	Jet Impingement	No	Submit a review of affected jet impingement analysis.	Yes	12/82	-
	4.10.3	Unisolable Breaks	No	None	-	-	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-6	4.11.1	Pile Foundations	No	Evaluate structural capability of piles supporting the turbine and gas turbine buildings. (See Sections 4.2.1, 4.2.2, and 4.12.)	Yes	10/83	-
	4.11.2	Motor-Operated Valves	No	Demonstrate valve structural integrity.	No response	-	-
	4.11.3	Low-Pressure Coolant Inspection/Containment Spray Heat Exchangers	No	None	-	-	-
	4.11.4	Transformer and Control Room Panels	No	None (staff is reviewing).	-	-	-
	4.11.5	Ability of Safety-Related Electrical Equipment To Function	No	None	-	-	-
	4.11.6	Qualification of Cable Trays	No	Provide plan to implement results of SEP Owners Group Program.	Yes	4/83	-
	4.11.7	Recirculation Pump Supports	No	None	-	-	-
	4.11.8	Reactor Vessel Internals	No	Provide a seismic analysis of the reactor vessel internals.	No response	-	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
III-7.B	4.12	Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria	No	Evaluate adequacy of original design criteria on a sampling basis for specified structural elements; provide information requested in Topics II.3.B, II-4.F, III-2, III-3.A, and III-6 that has been deferred to this topic.	Yes	10/83	-
III-8.A	4.13	Loose-Parts Monitoring and Core Barrel Vibration Monitoring	No	None	-	-	Yes
III-10.A	4.14	Thermal-Overload Protection for Motors of Motor-Operated Valves	No	Demonstrate proper setting of thermal-overload trip setpoints and discuss operating experience of specified valves.	Yes	1/83	Yes
				Implement modifications found to be necessary.	Yes	1984 refueling outage	-
IV-2	4.15	Reactivity Control Systems, Including Functional Design and Protection against Single Failures	No	None	-	-	-
V-5	4.16.1	Systems Currently Available at Millstone Unit 1	No	Provide at least one leakage detection method that is qualified to a safe shutdown earthquake and testable during operation.	No response	-	Yes
				Evaluate sensitivity in conjunction with Topic III-5.A. (See Section 4.9.1.)	Yes	11/82	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
V-5	4.16.2	Intersystem Leakage	No	None	-	-	-
V-10.B	4.17	Residual Heat Removal System Reliability	No	Review and implement emergency procedures, including steps to proceed to a cold shutdown condition from outside the control room.	Yes	1984 refueling outage	Yes
V-11.A	4.18	Requirements for Isolation of High- and Low-Pressure Systems	No	Install an independent pressure interlock for the reactor water cleanup (RWCU) system inboard suction isolation valve.	Yes	Spring 1984	Yes
V-12.A	4.19.1	Water Chemistry Limits	Yes	Revise Technical Specifications to incorporate RG 1.56 limits for chlorides and conductivity limits, or provide justification for not doing so.	Yes	2/83	-
	4.19.2	Limiting Conditions for Operation	Yes	Incorporate in the Technical Specifications procedural requirements for maintaining minimum reserve capacity of the RWCU and condensate systems demineralizers, or provide justification for not doing so.	Yes	2/83	-
VI-4	4.20.1	Locked-Closed Valves	No	Install administratively controlled mechanical locking devices in the specified valves.	Yes	-	Yes

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
VI-4	4.20.2	Lines Requiring a Second Valve and Both Locked Closed	No	Install a second valve and administratively controlled locking devices on both, on the specified lines.	No response	-	Yes
	4.20.3	Remote Manual Valves	No	Demonstrate leakage detection, locate operating stations in accessible areas, and develop procedures for isolation of the specified valves.	Yes	-	Yes
	4.20.4	Valve Location	No	None	-	-	Yes
	4.20.5	Instrument Lines	No	None	-	-	Yes
	4.20.6	Valve Location and Type	No	None	-	-	-
	4.20.7	Lack of Information	No	Review isolation capability of two lines and implement modifications, if necessary.	Yes	-	-
VI-7.A.3	4.21.1	Testing of Space Coolers	No	Demonstrate that the space coolers are not essential.	Yes	11/82	Yes
	4.21.2	Testing of the ESWS	No	None	-	-	-
VI.7.A.4	4.22	Core Spray Nozzle Effectiveness	No	None	-	-	-

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
VI-7.C.1	4.23.1	Automatic Bus Transfers	No	Evaluate the existing automatic bus transfers and identify corrective actions to ensure faulted loads would not be transferred.	Yes	11/82	Yes
	4.23.2	Manual Bus Transfers	No	Install appropriate interlocks or provide justification for not doing so.	Yes	11/82	Yes
VI-10.A	4.24.1	Surveillance Frequency	Yes	Increase surveillance frequency of the specified channels.	No	-	Yes
	4.24.2	Channel Functional Test Frequency	Yes	Revise Technical Specifications to meet Standard Technical Specification requirements.	No	-	Yes
	4.24.3	Response-Time Testing	No	None	-	-	Yes
VII-1.A	4.25.1	Isolation Devices Between Reactor Protection System (RPS) and Monitoring Systems	No	Conduct test to determine if existing isolation is adequate. Propose corrective actions if necessary.	Yes	11/82	Yes
	4.25.2	Isolation Devices Between the RPS and its Power Supply	No	Provide adequate isolation.	Yes	12/82	-
VII-3	4.26	Systems Required for Safe Shutdown	No	None	-	-	Yes

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Comple-tion date	PRA* review
VIII.1.A	4.27	Potential Equipment Failures Associated With Degraded Grid Voltage	No	Develop and implement procedures to protect Class 1E systems of a degraded grid voltage condition.	Yes	-	-
VIII-2	4.28.1	Startup Trips	No	Bypass light-off speed and generator excitation speed trips under accident conditions	Yes	1984 refueling outage	Yes
	4.28.2	Operational Trips	No	Bypass high lube oil temperature trip under accident conditions.	Yes	4/83	Yes
	4.28.3	Gas Turbine Preventive Maintenance Program	No	Implement a preventive maintenance program, improve existing one, or provide justification for not doing so.	No response	-	-
	4.28.4	Generator Trips	No	Bypass specified trips under accident conditions.	Yes	1984 refueling outage	Yes
	4.28.5	Annunciators	No	None	-	-	Yes
VIII-3.A	4.29	Station Battery Test Requirements	Yes	Revise Technical Specifications to require battery service and discharge tests.	Yes	1/83	Yes

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
VIII-3.B	4.30	DC Power System Bus Voltage Monitoring and Annunciation	No	Install the specified battery status alarms.	Yes	-	Yes
			Yes	Revise Technical Specifications to reduce battery outage limits or provide justification for present limits.	-	-	Yes
IX-3	4.31	Station Service and Cooling Water Systems	No	None (pending results of Topic II-4.F review).	-	-	Yes
IX-5	4.32.1	Core Spray and LPCI Systems Ventilation	No	Demonstrate that the space coolers are not essential. (See Section 4.21.1.)	Yes	11/82	Yes
	4.32.2	Reinitiation of Ventilation After a Loss-of-Offsite-Power Event	No	Demonstrate that the equipment serviced is unaffected by the lack of ventilation and that the hydrogen combustion limit in the battery rooms will not be reached.	Yes	2/83	Yes
	4.32.3	Lack of Information	No	Provide information on the space coolers for the feedwater coolant injection and diesel generator areas.	Yes	2/83	Yes
	4.32.4	Intake Structure Ventilation System	No	Demonstrate that sufficient ventilation can be provided in a timely manner.	Yes	2/83	Yes

*See Appendix D.

Table 4.1 (Continued)

SEP Topic No.	Section No.	Title	Tech. Spec. modifications required from SEP review	Backfit requirements	Licensee agrees	Completion date	PRA* review
XV-1	4.33	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	No	None currently; surveillance of turbine bypass valves and limits for reactor power if the turbine bypass is inoperable will be required if credit is taken for the turbine bypass in the reload analysis.	Yes	1984 refueling outage	Yes
XV-3	4.34	Loss of External Load Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)	No	None	-	-	Yes
XV-16	4.35	Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment	Yes	Implement BWR Standard Technical Specification limit for primary coolant activity.	No	-	-
XV-18	4.36	Radiological Consequences of a Main Steam Line Failure Outside Containment	Yes	See Section 4.35.	No	-	Yes

*See Appendix D.

Because of the higher water elevation resulting from wave effects, the floodwalls and walls above the floodwalls may not be adequate to resist these added forces. Additionally, because the wave heights are greater than the height of the floodwalls, there would be some inleakage.

The licensee has agreed to address the effects of inleakage under this topic and will provide the results to the staff by December 31, 1982 and implement any necessary corrective action. The licensee will address the structural concerns in SEP Topic III-3.A (Section 4.5.1) and in the Integrated Structural Assessment in Topic III-7.B (Section 4.12).

4.1.2 Intake Structure

It is possible to flood the intake structure by a PMH surge and high waves entering from the openings below. The service water pumps and emergency service water pumps are located in the intake structure.

The licensee is reviewing this concern and will inform the staff of the results by December 31, 1982 and implement any necessary corrective actions.

4.1.3 Local Flooding

Because of flooding from a local PMP, it is possible that ponding may occur in a partially surrounded area near the radwaste and control building (grade elevation in this area is 14.9 ft MSL). No credit is given for the floodgate, which would protect the structures from flooding, because ponding caused by a local PMP would occur very rapidly.

The licensee has stated that there is no safety-related equipment just past the opening where the floodgate is located. Although no credit has been given for the floodgate, a normally closed controlled access door exists at that opening and would provide some resistance to inleakage. Any water passing the door would have to travel down a corridor and pass through two additional doors in order to enter areas of the turbine building that house safety-related equipment. The licensee has stated that safety-related equipment, which could be affected by inleakage beyond these two additional doors, is protected because it either is located in watertight rooms or is sufficiently elevated. This equipment consists of

(1) feedwater coolant injection pumps, which are on mats whose elevation is 15.87 ft MSL (floor el 14.5 ft MSL)

(2) condensate booster pumps, which are on mats whose elevation is 17 ft MSL (floor el 14.5 ft MSL)

(3) condensate pumps, which are at floor level; however, the pumps are surrounded by grating so that water would drain through the grating to a room below where no safety-related equipment exists; additionally, the motors are elevated above floor level

(4) Unit 2 auxiliary feedwater pumps, which are located in watertight rooms

The staff agrees with the licensee's conclusion and considers the issue of ponding near the control and radwaste building resolved.

4.1.4 Gas Turbine Building

The gas turbine building may become flooded during a local PMP since ponding was noted in that vicinity during a site visit. There are cable trays and conduits approximately 6 in. above floor elevation inside the gas turbine building. Floor elevation is 14.5 ft MSL.

The licensee does not believe that flooding of the gas turbine building is a concern because

(1) It appears that, according to topographic maps, water in that area would drain to the Long Island Sound.

(2) The alternate diesel generator would not be affected by such flooding and would be available to supply onsite power.

(3) It is possible to use the isolation condenser to shut down. The isolation condenser requires makeup water that can be obtained from the condensate storage tank by means of the condensate transfer pumps or from the firewater tanks by means of motor-driven fire pumps or a diesel-driven fire pump. One of the motor-driven firewater pumps receives emergency power from Millstone Unit 1, the other from Millstone Unit 2.

The staff concludes that, in general, water from the area of the gas turbine building would drain toward the Long Island Sound since the overall topography of the site slopes in this direction; however, some accumulation near the gas turbine building can still be expected during a PMP because of a localized depression in the vicinity of the gas turbine building (the elevation of the slab inside is slightly less than the elevation outside (el 14.5 ft vs el 14.9 ft MSL)). Electrical cables in the gas turbine building are approximately 6 in. above the slab. There is a storm drain directly in front of the building that the staff did not evaluate during the topic review which could alleviate local flooding effects; however, the staff normally assumes such drains to be blocked during flood events. The alternate diesel generator would not be affected by floods since it was not identified as vulnerable to floods in the topic review; a loss of offsite power during the flood and failure of the diesel to start would result in no onsite power as a result of flooding of cables in the gas turbine building. In this case, shutdown can be achieved using the isolation condenser. Without the use of ac power, makeup water can be delivered to the isolation condenser by use of the diesel fire pumps. These are not subject to local flooding since they were not identified as vulnerable to flooding in the topic review. As an added measure, the licensee has agreed to keep the large flood door on the gas turbine building closed as part of the operating procedures pertaining to the flood door. The other door is a controlled access door normally closed which, although not a flood door, would assist in preventing water from entering the building. Because of the alternate shutdown capability and the extra protection obtained by keeping the large flood door closed, backfitting is not recommended.

4.1.5 Diesel Fuel Oil

The diesel fuel oil transfer pumps are susceptible to wave action during a PMH. The electrical motors are located at 21.0 ft MSL or 1.3 ft below the PMH wave-action height.

Shutdown can be achieved and maintained by use of the isolation condenser and diesel-driven firewater pumps. The oil capacity for the diesel-driven firewater pumps allows operation for 12 hours and these pumps are located in a flood-protected structure. Thus, shutdown can be maintained for 12 hours if offsite power is lost and the diesel fuel oil transfer pump is flooded. Because of the conservatism in the calculation of the PMH wave height and the small difference between the elevation of the fuel oil transer pump and the PMH wave height and because shutdown can be maintained for 12 hours, backfitting is not recommended. However, flood emergency procedures should be revised to address shutdown with a loss of offsite power and failure of the fuel oil transfer pumps as indicated in the next section.

4.1.6 Emergency Procedures

The flood emergency procedure (OP514A) at Millstone Unit 1 is considered deficient in the following areas:

(1) The procedures are not designed to protect against a local PMP.

(2) The water level (14.0 ft MSL) at which emergency procedures are to begin is too high.

(3) The time to perform the procedures is not specified.

(4) Communications currently relied on may be damaged.

(5) Items of OP514A are not specific enough. OP514A should specify the number of personnel required to cover all areas needing assistance, listing of actions to be performed and equipment to be used, and inclusion in the checklists of the titles of personnel to be informed of plant conditions and status of completion.

(6) Actions for gross leakage at a floodgate are not given.

(7) Flood emergency procedures should address shutdown without offsite power and failure of the fuel oil transfer pump. These are relied on to resolve flooding issues related to the diesel fuel transfer pumps discussed in Section 4.1.5.

The licensee is currently reviewing his flood emergency procedures relative to the above concerns and will revise them where necessary. The licensee intends to complete the review, inform the staff of the results, and implement a revised procedure by December 29, 1982.

The staff finds this acceptable.

4.1.7 Roofs

Some roofs with parapets may be overstressed as a result of a local PMP.

The licensee has agreed to address this concern by analyzing the roofs of safety-related structures and initiating corrective action, if necessary. The licensee intends to perform this analysis in conjunction with the review of SEP Topic III-7.B and will provide the results to the staff by October 31, 1983.

4.2 Topic II-4.F, Settlement of Foundations and Buried Equipment

10 CFR 50 (GDC 2 and 44) and 10 CFR 100, Appendix A, as implemented by Regulatory Guide 1.132 and SRP Section 2.5.4, require that foundations and buried equipment important to safety be adequately designed to perform their intended functions. During the staff review the following issues were identified.

4.2.1 Turbine Building

The turbine building is a pile-supported structure (the piles are steel H-piles). The licensee has not demonstrated that the piles will provide adequate lateral resistance to the horizontal loads that will develop during the safe shutdown earthquake (SSE). Additionally, the embedment of the piles into the foundation mat may be inadequate to resist the lateral or uplift loading associated with the SSE because the embedment appears to be as little as 4 in. The potential for corrosion of the piles and subsequent reduction of support capacity needs to be investigated and corrective actions taken, if appropriate.

The licensee has proposed to perform this analysis as a part of the Integrated Structural Analysis in SEP Topic III-7.B (Section 4.12).

4.2.2 Gas Turbine Generator Building

Because the gas turbine building is supported on piles like the turbine building, the concerns in Section 4.2.1 are applicable. Additionally, some of the piles under this building are friction piles. The licensee has not demonstrated that they will perform adequately during dynamic loading because there could be a loss of strength in the saturated granular soils surrounding these piles during dynamic loading associated with the SSE. The loss of strength could cause large vertical settlements of the building.

To address the staff's concerns related to the turbine building and gas turbine building piles, the licensee has proposed to investigate the adequacy of the pile embedment, the lateral load capacity of the piles, and the effects of corrosion on the piles. The licensee will also analyze the ability of the friction piles for the gas turbine building to resist settlement resulting from dynamic loads. The licensee has proposed to perform this analysis as a part of the Integrated Structural Analysis in SEP Topic III-7.B (Section 4.12).

4.2.3 Buried Pipelines

One area of the safety-related water pipelines may be supported on unsuitable peat materials. This area is located about 200 ft southeast of the intake structure over a former swale. The pipelines are located a few feet above original grade, on compacted fill. However, the swale may not have been excavated sufficiently to remove underlying peat. According to construction records, peat is located beneath a few feet of medium dense to dense, surficial granular materials. The need to remove the apparently suitable granular materials to reach and remove the unsuitable peat materials would not have been obvious during construction. Also, there are no records of dewatering that would have been needed during construction to excavate the peat. If the pipelines are located over peat, significant settlement could have occurred and could be continuing; peat is highly compressible and overburden loads have been applied after the pipes were placed. However, there are no visible surface indications of subsurface settlement, such as cracking of the asphalt pavement. It is the staff's position that the soils beneath the safety-related water pipelines should be investigated in the area where they may be underlain by peat.

To address the staff's concern related to ground support of the service water and emergency service water lines, the licensee has proposed to conduct soil investigations, possibly including new borings, in the area of these buried pipe runs. The licensee has proposed to address this issue as a part of the Integrated Structural Analysis in SEP Topic III-7.B (Section 4.12).

4.3 Topic III-1, Classification of Structures, Components, and Systems (Seismic and Quality)

10 CFR 50 (GDC 1), as implemented by Regulatory Guide 1.26, requires that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of safety functions to be performed. The codes used for the design, fabrication, erection, and testing of the Millstone Unit 1 plant were compared with current codes.

The development of the current edition of the American Society of Mechanical Engineers "Boiler and Pressure Vessel Code" (ASME Code) has been a process evolving from earlier ASME Code, American National Standards Institute, and other standards, and manufacturer's requirements. In general, the materials of construction used in earlier designs provide comparable levels of safety.

The review of this topic identified several systems and components for which the licensee was unable to provide information to justify a conclusion that the quality standards imposed during plant construction meet quality standards required for new facilities. The staff did not identify any inadequate components. However, because of the limited information on the components involved, the staff was unable to conclude that, for code and standard changes deemed important to safety, the Millstone Unit 1 plant met current requirements. Information in the following areas has been requested in the Safety Evaluation Report (SER) forwarded by letter dated May 5, 1982.

It is the staff's position that the licensee complete the six evaluations described below and incorporate the results in the Final Safety Analysis Report update, which must be submitted within 2 years after completion of the SEP review (10 CFR 50.71). If the results of the licensee's evaluations indicate that facility modifications are required, those actions should be reported to the staff. The licensee has agreed to this action.

4.3.1 Radiography Requirements

ASME Code, Section III, requires that Category A, B, and C weld joints be radiographed. Furthermore, ASME Code, Section III, 1977 Edition requires that weld joints for Class 1 and 2 piping, pumps, and valves be radiographed.

Because information was not available during the review, the staff concludes that the licensee should verify that all Class 1 and 2 piping, pumps, and valves and Class 2 vessels have been radiographed or subsequently volumetrically inspected. If neither has been done, the licensee should perform a volumetric inspection.

4.3.2 Fracture Toughness

ASME Code, Section III, imposes minimum fracture toughness requirements on certain carbon steel components. For 62 of the 66 components reviewed, the information was not sufficient to complete this review.

The licensee should identify whether the remaining components, identified in the Franklin Technical Evaluation Report C5257-432 appended to the staff's SER forwarded by letter dated May 5, 1982, are exempt from fracture toughness requirements (i.e., austenitic stainless steel or other criteria). The licensee should perform an evaluation of those items that are not exempt from current fracture toughness requirements to determine if toughness of the material for the remaining components is sufficient to preclude brittle failure and, if it is not, evaluate the consequences and demonstrate acceptability or replace the components.

4.3.3 Valves

Current ASME Code, Section III, design requirements regarding body shapes and Service Level C stress limits for Class 1 valves and pressure-temperature ratings for Class 2 and 3 valves are different from those used when the plant was designed. Sufficient information was not available to assess the valves in the above-stated areas.

The licensee should verify, on a sampling basis, that Class 1 valve stress limits meet current criteria for body shape and Service Level C conditions and that the pressure-temperature ratings of Class 2 and 3 valves are comparable to current standards. If current criteria are not met, the licensee should take appropriate corrective action (analysis or upgrading).

4.3.4 Pumps

For the recirculation system pumps, a demonstration of compliance with the current fatigue analysis requirements should be provided. All pumps with the exception of low-pressure coolant injection/containment coolant subsystem pumps and the reactor building closed cooling water (RBCCW) system pumps were designed to ASME Code, Sections III or VIII, 1965 Edition. Information concerning these pumps is not available.

The licensee should evaluate the design standards used for these pumps in relation to current design standards and identify whether adequate safety margins exist.

4.3.5 Storage Tanks

Compressive stress requirements for atmospheric storage tanks and tensile stress requirements for 0- to 15-psig storage tanks designed according to ASME Code, Section III, Class C (1965), or ASME Code, Section VIII (1965), differ from those in the current ASME Code, Section III, Class 2. Sufficient information was not available to assess the significance of these changes for the two tanks designed to earlier ASME Code editions.

The licensee should perform the following evaluations:

(1) If the standby liquid control system and condensate storage tanks were not designed to ASME Code, Section III, Class C, or ASME Code, Section VIII, the licensee should reevaluate the design and construction of the tanks against current criteria.

(2) If such tanks were designed to ASME Code, Section III, Class C, or ASME Code, Section VIII, the licensee should confirm that the atmospheric storage tanks meet current compressive stress requirements or confirm that the 0- to 15-psig storage tanks meet current tensile allowables for biaxial stress field conditions.

4.4 Topic III-2, Wind and Tornado Loadings

10 CFR 50 (GDC 2), as implemented by SRP Sections 3.3.1 and 3.3.2 and Regulatory Guides 1.76 and 1.117, requires that the plant be designed to withstand the effects of natural phenomena such as wind and tornadoes.

The existing design and construction of some structures important to safety do not meet current licensing criteria regarding the ability of safety-related structures to resist tornado winds of 300 mph and differential pressures of 2.25 psi. The following were identified by the staff as items not meeting the prescribed loads.

4.4.1 Reactor Building Steel Structures Above the Operating Floor

The capacities calculated by the staff were lower than those required for the site-specific tornado-imposed loads. The licensee is analyzing these structures as part of the Integrated Structural Analysis in SEP Topic III-7.B to determine capacities and will provide the results and identify any proposed corrective actions to the NRC upon completion. The analysis is scheduled to be completed by October 31, 1983. The staff finds this acceptable.

4.4.2 Ventilation Stack

The stack capacities calculated by the staff are lower than those required by the site-specific tornado-imposed loads. Failure of the stack could affect the integrity of seismic Category I structures. The licensee has proposed to demonstrate that failure of the stack will not prevent either Units 1 or 2 from achieving and maintaining safe shutdown. The licensee has agreed to submit such an evaluation to the staff by November 30, 1982. The staff finds this acceptable.

4.4.3 Effects of Failure of Nonqualified Structures

There was insufficient information to determine the effects of structural failure of nonqualified structures on other structures (e.g., upper level of reactor building on the control room; upper portion of the turbine building on the switchgear room). The licensee has agreed to perform the review, identify any necessary corrective actions, and submit the results to the staff by October 31, 1983.

4.4.4 Components Not Enclosed in Qualified Structures

During the topic review, components not inside qualified structures were to be reviewed by the licensee. The licensee has agreed to perform such an evaluation, identify any necessary corrective actions, and submit the results to the staff by October 31, 1983.

4.4.5 Roofs

During the topic review the staff did not analyze roofs with the exception of that of the gas turbine building. The roofs of the switchgear and battery room are only 4-in.-thick reinforced concrete and, therefore, may not have the required tornado resistance; the roof of the ventilation equipment area is composed of builtup roof decking, which is also expected to have negligible tornado resistance.

The licensee has agreed to determine the effects of roof failure and/or capacities of the roofs of Category I structures, identify any necessary corrective action, and supply the results to the staff by October 31, 1983. The licensee intends to do this as part of the Integrated Structural Analysis in SEP Topic III-7.B (Section 4.12).

4.4.6 Load Combinations

As a result of the topic review, the staff was unable to determine if straight wind loads (not tornado loads) were combined with other loads (i.e., snow loads, operating pipe reaction loads, and thermal loads).

The licensee will review this as part of the Integrated Structural Analysis in SEP Topic III-7.B (Section 4.12), identify any necessary corrective action, and submit the results to the staff by October 31, 1983.

4.5 Topic III-3.A, Effects of High Water Level on Structures

10 CFR 50 (GDC 2), as implemented by SRP Section 3.4 and Regulatory Guide 1.59, requires that plant structures be designed to withstand the effects of flooding. The safety objective of this topic is to ensure the function of safety-related structures with hydrostatic or hydrodynamic loading resulting from design-basis water levels when combined with other nonaccident loadings. The staff's review of this topic identified the following areas of concern. The licensee has agreed to address the following concerns as part of the Integrated Structural Analysis being performed in SEP Topic III-7.B (Section 4.12). The results will be submitted to the staff by October 31, 1983.

4.5.1 Flood Elevation

The results of the review of SEP Topic II-3.B conclude that a standing wave reaching 22.3 ft MSL would form during the PMH. The plant was originally designed for a static water level at 19.0 ft MSL. Therefore, hydrostatic forces resulting from a standing wave to 22.3 ft MSL may cause structural damage to the floodwalls, which extend to 19.0 ft MSL, and the walls above.

4.5.2 Groundwater

The licensee has stated that plant structures were designed to resist hydrostatic and uplift forces resulting from groundwater rising to grade. The licensee should determine whether these loads have been considered in the proper load combination by reviewing original design information or demonstrate acceptability by analysis on a sampling basis.

4.6 Topic III-3.C, Inservice Inspection of Water Control Structures

10 CFR 50 (GDC 2, 44, and 45), as implemented by Regulatory Guide 1.127, requires that structures, systems, and components important to safety be designed to withstand natural phenomena such as floods and that a system to transfer heat to an ultimate heat sink be provided. The inspection is intended for water control structures used for flood protection (on or off site) and emergency cooling water systems. The safety objective is to ensure that water control structures that are part of the ultimate heat sink are available at all times during both normal and accident conditions. The topic review identified the following items.

4.6.1 Deficiencies Noted During Site Visit

During the site visit, deficiencies related to flood protection were noted. These items are identified below with the licensee's comments.

(1) Floodgates on the south side of the plant will not close because of interference caused by handrails.

    The licensee has stated these handrails were installed with bolts in the concrete instead of the embedment so that they could be removed before a hurricane. However, the licensee has since removed the handrails permanently.

(2) Some flood door gaskets were not in place.

    The licensee has stated that the gaskets were not in place because at the time of the site visit, old seals were being replaced with new ones as part of routine maintenance. The staff has since verified that the gaskets are in place.

(3) Two of the turbine building roof drains were inoperable.

    The licensee has stated that two of the four drains were inoperable because they had been identified as a potential radiological release path. Additionally, the roof parapets on this particular building are low; therefore, the roof would not be overstressed.

The staff had pointed out this item as being possibly indicative of the condition of other roof drains at the plant because it had only viewed a limited number. If this were the case with other drains on roofs with higher parapets and the remaining drainage or structural capacities of the roof were not considered, roof failure could result. The licensee has committed to reanalyze the roofs to determine their ability to resist loads from ponding water. If credit is taken for roof drains, the licensee must demonstrate adequacy and availability of the drains. This analysis will be performed as part of the Integrated Structural Analysis in SEP Topic III-7.B (Section 4.12).

(4) Rainwater does not drain properly in the vicinity of the gas turbine building. This issue is addressed under SEP Topic II-3.B (Section 4.1.4).

(5) Electrical cables in the gas turbine building are not flood protected. This is addressed under SEP Topic II-3.B (Section 4.1.4).

4.6.2 Structures and Components Requiring Inspection

The staff has reviewed the licensee's current inspection program and concluded that inspection of floodwalls and floodgates was not included on the licensee's list of structures to be inspected; however, the licensee has stated that he currently does inspect the floodgates.

The staff finds this acceptable; however, floodwalls should also be inspected and both should be included on the list of structures to be inspected. The licensee has proposed to coordinate this procedural revision with the inspection program discussed in Section 4.6.3.

4.6.3 Inspection Program

The staff's evaluation noted that a formal inspection program, including documentation and followup review, should be conducted for water control structures.

The licensee has committed to develop and implement an inspection program for water control structures, including reporting, that will be conducted and reviewed by qualified personnel. The licensee will submit this inpection program to the staff by December 30, 1982. The staff finds the licensee's proposed action acceptable.

4.7 Topic III-4.A, Tornado Missiles

10 CFR (GDC 2), as implemented by Regulatory Guide 1.117, prescribes structures, systems, and components that should be designed to withstand the effects of a tornado, including tornado missiles, without loss of capability to perform their safety functions. Regulatory Guide 1.117 requires that structures, systems, and components that should be protected from the effects of a design-basis tornado are (1) those necessary to ensure the integrity of the reactor coolant pressure boundary, (2) those necessary to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition (including both hot standby and cold shutdown), and (3) those whose failure could lead to radioactive releases resulting in calculated offsite exposures greater than 25% of

the guideline exposures of 10 CFR 100 using appropriately conservative analytical methods and assumptions. The physical separation of redundant or alternate structures or components required for the safe shutdown of the plant is not considered acceptable by itself for providing protection against the effects of tornadoes, including tornado-generated missiles, because of the large number and random direction of potential missiles that could result from a tornado as well as the need to consider the single-failure criterion.

The following structures and components were identified as vulnerable to tornado missiles:

(1) service water and emergency service water pumps

(2) emergency switchgear

(3) emergency batteries and battery chargers

(4) emergency diesel generator and fuel oil day tank

(5) gas turbine

(6) safe shutdown cables (turbine building, yard cable trenches, intake structure, and gas turbine building)

(7) condensate storage tank

(8) control room heating, ventilation, and air conditioning

(9) space coolers

  (a) turbine building ventilation servicing switchgear rooms, emergency diesel generator, and battery room

  (b) intake structure ventilation system.

(10) turbine building secondary closed cooling water system

During the topic review, the condensate and condensate booster pumps and their space coolers and the reactor feedwater pump M2-10C were identified as potentially vulnerable to tornado missiles, based on a review of drawings. The condensate and condensate booster pumps were identified as vulnerable because only masonry block walls existed between the pumps and the outside. During the site visit, however, it was noted that two masonry walls are separated by a large distance and that intervening equipment exists between the pumps and the exterior. The staff judged that this provided adequate protection.

Feedwater pump M2-10C was vulnerable because it is protected by a masonry block wall to the east. Masonry block is not considered adequate protection. During the site visit, however, it was noted that only a portion of the wall is made of masonry block; the rest is concrete. Feed pump M2-10C is located near the concrete wall and is adequately protected. Further, feedwater pump M2-10C is not safety related because it is not part of the emergency feedwater coolant injection system (FWCI).

The licensee believes that sufficient power and water source redundancy exist to ensure the capability to safely shut down the plant. This is described in the licensee's letter dated June 29, 1982. In that letter, the licensee described various shutdown methods if vulnerable components described in the SER (forwarded by letter dated May 25, 1982) are unavailable; however, the licensee has not described any method of shutdown using only systems and components protected from tornado missiles. The licensee's methods rely on redundancy of unprotected equipment. Application of single-failure criteria alone because of missile damage is not considered appropriate. Experience with tornadoes indicates that debris, multiple missiles, and damage to exposed equipment is likely. This is also embodied in the NRC's regulations, 10 CFR 50, Appendix A, GDC 4. Because the reactor coolant pressure boundary is adequately protected, it is not recommended that all safety-related systems (i.e., accident-mitigating systems) be protected from tornado missiles. However, it is the staff's position that the licensee must provide protection for sufficient systems and components to ensure the ability to safely shut down (i.e., hot shutdown) in the event of damage from tornado missiles.

By letter dated September 22, 1982, the licensee disagreed with the staff's position. However, during the October 26, 1982 Advisory Committee on Reactor Safeguards (ACRS) Subcommittee meeting, the licensee proposed to evaluate alternatives and provide a shutdown method that is protected from the effects of tornado missiles.

4.8 Topic III-4.B, Turbine Missiles

10 CFR 50 (GDC 4), as implemented by Regulatory Guide 1.115 and SRP Section 3.5.1.3, requires that structures, systems, and components important to safety be appropriately protected against dynamic effects, which include potential missiles. The safety objective of this review is to ensure that all the structures, systems, and components important to safety (identified in Regulatory Guide 1.117) have adequate protection against potential turbine missiles because of either structural barriers or a high degree of assurance that failures at design or destructive overspeed will not occur.

General Electric (GE) is currently analyzing the probability of generating turbine missiles generically for its turbine designs. This analysis will consider material properties, turbine disc design, inservice inspection intervals, and overspeed protection system characteristics as they relate to destructive overspeed missile generation. The results of this analysis will be submitted to the staff and will identify recommended inspection intervals for the disc and overspeed protection system based on plant-specific turbine characteristics and test results. On the basis of the results of the last turbine inspection, GE has recommended a schedule to all owners for the next inservice inspection (ISI) based on GE's crack-growth models. The time interval can range from 18 months to 6 years.

Until a turbine inspection frequency is established generically for the GE turbines, the staff recommends that the low-pressure turbine discs and normally inaccessible parts that have not been inspected in the last 3 years in accordance with the turbine manufacturer's recommended procedures be inspected at the next refueling outage in accordance with those procedures. Based on the inspection results, the licensee is to propose a schedule for future inspections. Further, it is the staff's position that main steam stop and control valves and reheat stop and intercept valves be disassembled and inspected at approximately 3-year intervals and be exercised at least weekly by full closure of the valve. The licensee's proposed schedule for future inspections of the turbine and associated overspeed protection system should include consideration of the recommendations of the turbine manufacturer.

The licensee reported by letter dated September 29, 1982a, that inspections and tests of the main steam stop, reheat stop, and intercept valves are performed in conformance with the staff's position. However, the control valves are not tested by fully closing the valves. These valves are frequently changing positions as a result of load changes. It is the staff's position that the licensee evaluate the potential improvement in control valve availability associated with weekly full closure testing and the feasibiilty of conducting such tests.

The licensee has agreed to propose a future inspection schedule based on the results of the inspections conducted during the 1982 refueling outage. The staff finds this acceptable.

4.9 Topic III-5.A, Effects of Pipe Break on Structures, Systems, and Components Inside Containment

10 CFR 50 (GDC 4), as interpreted by SRP Section 3.6.2, requires, in part, that structures, systems, and components important to safety be appropriately protected against dynamic effects such as pipe whip and discharging fluids. The safety objective for this topic review is to ensure that if a pipe should break inside the containment, the plant could safely shut down without a loss of containment integrity and the break would pose no more severe conditions than those analyzed by the design-basis accidents. The staff review of this topic identified the following three issues.

4.9.1 Cascading Pipe Breaks

On the basis of information available during the topic review, the staff was unable to conclude that cascading pipe breaks would not produce conditions more severe than those analyzed by the limiting design-basis loss-of-coolant accident (LOCA). The staff concludes that the potential for cascading pipe breaks should be analyzed to ensure that the effects of such breaks do not compromise the ability of the plant to achieve a cold shutdown or mitigate the consequences of an accident. The licensee should demonstrate that cascading pipe breaks will not result in conditions more severe than those previously analyzed. Alternatively, the licensee should provide a leakage detection system inside the drywell using Regulatory Guide 1.45 criteria with a detection sensitivity sufficient to detect through-wall cracks substantially smaller in size than the critical flaw size from a piping fracture mechanics analysis. This will ensure that pipe cracks are detected before they can propagate into pipe breaks. Thus, the potential for cascading pipe failures will be acceptably low. The staff has taken a similar position for the resolution of Unresolved Safety

Issue A-2 ("Asymmetric LOCA Loads") for PWR primary systems. Guidance for performing these evaluations is contained in the staff's lead topic safety evaluation report for Palisades submitted by letter to Consumers Power Company dated December 4, 1981.

Any leakage detection systems deemed necessary should be reviewed in conjunction with SEP Topic V-5, "Reactor Coolant Pressure Boundary Leak Detection" (Section 4.16).

The licensee will submit his analysis of cascading pipe breaks to the staff by December 15, 1982. The evaluation of conformance to Regulatory Guide 1.45 is discussed in Section 4.16.

4.9.2 Jet Impingement

The licensee was asked to address the following aspects of his jet impingement analysis.

(1) The jet impingement model used by the licensee was based on a jet expansion caused by longitudinal breaks; current criteria require the consideration of both circumferential and longitudinal breaks.

(2) In the case of circumferential breaks, jets in conjunction with pipe whip have not been considered to sweep the arc traveled by the whip.

(3) The assumption used by the licensee appears to refer only to steam jets rather than all high-energy lines.

(4) From the information presented, it is uncertain whether the jet impingement effects on the impinged target piping system conform with the staff position outlined in the letter transmitted to the licensee on January 4, 1980.

The licensee has agreed to address these four items and submit the necessary clarifications to the staff by December 15, 1982.

4.9.3 Pipe Whip

The staff asked the licensee to justify why pipe breaks leading to pipe whip cannot penetrate the drywell.

The licensee submitted the Chicago Bridge and Iron Company (CB&I) Test Report, "Loads on Spherical Shells" (Thullen, 1964) in support of his analysis. However, since the test was performed under essentially static conditions, it is not clear that the test result is also valid for the dynamic loading that would be experienced as a result of the postulated pipe whip for Millstone Unit 1. Additionally, the particular test applied a concentrated load of 235 tons over an area equivalent to a 14-in.-diameter or larger circle. This assumption may not always be valid because the impact area of a 14-in.-diameter or larger pipe may be smaller than the assumed area. Thus, the staff's concern is that in the case of the application of a concentrated dynamic load over a small area, the steel plate may be perforated before the deformation could be backed up by the concrete shield wall. It is also noted that the CB&I test was performed on a spherical steel plate section for a 70-ft-diameter sphere with a plate thickness of 0.75 in. However, the thickness of the Millstone Unit 1 drywell liner is only five-eighths of an inch. It is the staff's position that the licensee should select a worst-case configuration to demonstrate that the impact load or energy produced as a result of a postulated pipe break for piping of 14-in. diameter or more does not exceed the load or energy required to penetrate the containment liner and wall. In performing this evaluation with static analysis or static test, the dynamic load factor has to be considered.

The licensee has proposed to evaluate the potential for and consequences of pipes whipping into the drywell liner and will submit the results to the staff by December 15, 1982.

4.10 Topic III-5.B, Pipe Break Outside Containment

10 CFR 50 (GDC 4), as implemented by SRP Sections 3.6.1 and 3.6.2 and Branch Technical Positions (BTP) MEB 3-1 and ASB 3-1, requires, in part, that structures, systems, and components important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures. The safety objective for this topic review is to ensure that if a pipe should break outside the containment, the plant can be safely shut down without a loss of containment integrity. The staff review of this topic identified the following three issues.

4.10.1 Moderate-Energy Piping

Current criteria require that through-wall leakage cracks be postulated in moderate-energy line piping (temperature <200°F and pressure <275 psig). The licensee did not address this subject in this SEP topic assessment. A review of the effects of failures in non-Category I piping was submitted to the staff by the licensee in a letter dated October 2, 1972. The staff concluded in a letter dated March 27, 1974 that Millstone Unit 1 had adequate design features for protection against the rupture of a non-Class 1 component or piping.

The staff requested the licensee to

(1) verify that the previous reviews enveloped the potential flooding and spray effects of leakage cracks in moderate-energy piping (both Class 1 and non-Class 1), or

(2) provide an evaluation of the effects on safety-related equipment of leakage cracks in accordance with current review criteria

In a letter dated June 28, 1982, the licensee provided the results of an analysis of the moderate-energy systems (turbine building component cooling water, reactor building component cooling water, secondary cooling, fuel pool cooling systems, etc.) not previously covered in his October 2, 1972 letter. A review of the above moderate-energy systems indicates that any gross flooding in the turbine building would occur at the 14-ft-6-in. level and in the condenser bay. This flooding could have an effect on the feedwater coolant injection system; however, the emergency core cooling system would remain available for plant shutdown. The flooding that would occur in the reactor building flows down to the -26-in. level and into the corner rooms through the equipment hatch and stairwells.

The consequences of flooding of these areas do not prevent safe shutdown and are, therefore, acceptable. The wetting or spraying of safety-related electrical equipment is being addressed generically as part of the environmental qualification of electrical equipment. All safety-related motor control centers are protected from spray or dripping by recently installed watertight enclosures.

Subject to completion of the environmental qualification of electrical equipment, which is being performed independently of SEP, the staff considers this issue resolved; therefore, further analysis by the licensee is not warranted. Backfitting is not recommended.

4.10.2 Jet Impingement

The criteria used by the licensee to evaluate the effects of jet impingement loads resulting from postulated pipe breaks require clarification. For the isolation condenser system, the licensee references The Theory of Turbulent Jets (Abramovich, 1963) in his jet impingement load evaluation for steam or water-steam mixtures. SRP Section 3.6.2 states that the jet area expands uniformly at a half angle not exceeding 10°. The staff's assessment, based on the information currently available, is that the licensee's jet expansion model for the isolation condenser system results in a nonconservative calculation of the jet impingement load on targets that are more than five pipe diameters from the break location.

For the remainder of the systems evaluated by the licensee, the forces generated by the jets are given; however, the criteria used to calculate these forces are not identified.

It is the staff's position that the licensee should (1) validate the Millstone Unit 1 jet impingement evaluation methods, (2) demonstrate that the differences between his criteria and those in SRP Section 3.6.2 are not significant from the standpoint of consequences on systems, or (3) perform augmented ISI to demonstrate that unstable pipe failure is unlikely and implement local leakage detection.

In a letter dated June 28, 1982, the licensee has agreed to perform a review of the affected jet impingement analysis. The results of this review will be provided to the staff by December 15, 1982.

4.10.3 Unisolable Breaks

Postulated pipe breaks outside the primary containment, between the penetration and the containment isolation valve, in combination with an independent failure of the inside containment isolation valve could result in an unisolable break. Any break downstream of the outside isolation valve that damages either the valve itself or the control or power cables for the valve could result in a similar situation. Currently, the staff applies the provisions of BTP MEB 3-1, Section B.1.b, and BTP ASB 3-1, Section B.2.C, to the review of these areas. The intent is to ensure that a pipe break between the outside isolation valve and the containment wall is unlikely. This is accomplished by ensuring low pipe stress (BTP MEB 3-1) and high-quality pipe.

Stress data are not available to demonstrate that piping systems between the containment penetration and the isolation valve outside containment meet the stress limits of BTP MEB 3-1. Based on plant piping layout, it is likely that these stress limits would not be met.

Detailed information on piping system design for Millstone Unit 1 was not available to perform a plant-specific PRA. However, a limited risk assessment of the importance of the pipe breaks between the outboard isolation valve and the containment with a failure of the inboard isolation valve as unisolable LOCAs was conducted for Dresden Unit 2. It was determined that the LOCA frequencies associated with these pipe breaks are all less than 2×10^{-7} per year. Even if all these events led to core melt with release, the higher frequencies of other core-melt sequences coupled with the virtual certainty of containment failure after core melt makes these LOCAs negligible from a risk perspective. In addition, the small frequencies of pipe breaks result in a similar conclusion regarding the physical effects associated with the pipe break. Therefore, on the basis of the Dresden Unit 2 results, the importance to risk of pipe breaks between the containment penetration and the isolation valve outside containment at Millstone Unit 1 is low.

Backfitting, therefore, is not required.

4.11 Topic III-6, Seismic Design Considerations

10 CFR 50 (GDC 2) and 10 CFR 100, Appendix A, as implemented by SRP Sections 2.5, 3.7, 3.8, 3.9, and 3.10 and SEP review criteria (NUREG/CR-0098, "Development of Criteria for Seismic Review of Selected Nuclear Power Plants"), require that structures, systems, and components important to safety shall be designed to withstand the effects of natural phenomena, such as earthquakes, without loss of capability to perform their safety functions. The staff's review of this topic identified the following issues.

4.11.1 Pile Foundations

The adequacy of the pile foundation under the turbine building has not been demonstrated. This issue will be addressed by the licensee as part of the Integrated Structural Analysis in SEP Topic III-7.B.

4.11.2 Motor-Operated Valves

The structural integrity of small piping (4 in. or smaller) having motor-operated valves attached has been reviewed by the staff and found to be acceptable. This was noted in Attachment 2 to the staff's SER forwarded by letter dated June 30, 1982. This item is considered resolved.

The structural integrity of the valves has not been reviewed because of lack of information. It is the staff's position that the licensee demonstrate that the structural integrity of the valves is acceptable. The licensee has not responded with a proposed action for structural integrity of valves under postulated seismic loading.

4.11.3 Low-Pressure Coolant Injection/Containment Spray Heat Exchangers

The staff's concern was that the support of the heat exchangers might not be adequately restrained.

The licensee has submitted information concerning the installation of the heat exchangers. The staff has reviewed the restraints and mounting details and has found them to be adequate. Therefore, this issue is resolved.

4.11.4 Transformers and Control Room Panels

The design adequacy of the anchorage system of these two electrical equipment items might not be adequate to prevent the sliding or overturning of the equipment during a seismic event.

To demonstrate the adequacy of the anchorage systems for transformers and control room panels, the licensee has provided the staff with additional information on the anchorage design by letter dated September 29, 1982b. The staff is currently reviewing this response.

4.11.5 Ability of Safety-Related Electrical Equipment To Function

The ability of all safety-related electrical equipment to function, as well as the structural integrity of internal components of all the safety-related electrical equipment, is being evaluated, in part, through the SEP Owners Group program. This program is scheduled for completion by the end of 1982.

The NRC has initiated a generic program to develop criteria for the seismic qualification of electrical and mechanical equipment in operating plants as an unresolved safety issue (USI A-46) (see Appendix B). Under this program, an explicit set of guidelines (or criteria) that should be used to judge the adequacy of the seismic qualifications (both functional capability and structural integrity) of safety-related mechanical and electrical equipment at all operating plants will be developed. The ongoing SEP Owners Group program for equipment qualification will be considered in the development of the USI A-46 criteria and will subsequently be implemented through the generic program.

4.11.6 Qualification of Cable Trays

Qualification of electrical cable trays is being evaluated by testing through the SEP Owners Group program. This program is scheduled for completion by December 1982 and a plant-specific implementation program and implementation schedule will be submitted before April 1, 1983.

4.11.7 Recirculation Pump Supports

The staff has concluded that the recirculation pump case is adequate to ensure structural integrity; however, the staff was unable to evaluate pump snubber supports because of insufficient information.

The licensee has reviewed this issue as part of Office of Inspection and Enforcement Bulletin 79-14 and has committed to install support modifications as a result.

The staff finds this acceptable.

4.11.8 Reactor Vessel Internals

The staff has reviewed the shroud support and has concluded that it is acceptable; however, the staff was unable to conclude that other vessel internals are also acceptable because information was not available.

It is the staff's position that the licensee provide a seismic analysis of the reactor vessel internals to show that the balance of reactor vessel internals is adequate to withstand SEP-defined safe shutdown earthquake loading.

The licensee has not yet responded with a proposed action for reactor vessel internal structural integrity under seismic loading.

4.12 Topic III-7.B, Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria

10 CFR 50 (GDC 1, 2, and 4), as implemented by SRP Section 3.8, requires that structures, systems, and components be designed for the loading that will be imposed on them and that they conform to applicable codes and standards.

Code, load, and load combination changes affecting specific types of structural elements have been identified where existing safety margins in structures are significantly reduced from those that would be required by current versions of the applicable codes and standards. Twenty-eight specific areas of design code changes potentially applicable to the Millstone Unit 1 plant have been identified for which the current code requires substantially greater safety margins than did the earlier version of the code, or for which no original code provision existed.

The significance of the identified code changes cannot be assessed until a plant-specific review of their applicability, as well as of margins in the original design, is completed. This does not infer that existing structures have inadequate safety margins. The review, however, will clarify if the original margins are comparable to those currently specified and will include consideration of the appropriate applied loads (e.g., roof loading resulting from probable maximum precipitation and snow) and load combinations.

To address the concerns under this topic, the licensee proposed to perform, on a sampling basis, an evaluation of the code, load, and load combination issues on existing structures at the Millstone Unit 1 facility in order to assess the adequacy of the as-built structures. In addition, the licensee proposes to consolidate structural issues raised under other SEP topics and address them as part of the review of this topic in an Integrated Structural Assessment Program. Structural concerns raised under SEP Topics II-3.B, II-4.F, III-2, III-3.A, III-4.A, and III-6 and issues discussed above will be included in the program, with results to be submitted to the staff by October 31, 1983.

The staff finds this approach to resolve the issues acceptable.

4.13 Topic III-8.A, Loose-Parts Monitoring and Core Barrel Vibration Monitoring

10 CFR 50 (GDC 13), as implemented by Regulatory Guide 1.133, Revision 1, and SRP Section 4.4, requires a loose-parts monitoring program for the primary system of light-water-cooled reactors. Millstone Unit 1 does not have a loose-parts monitoring program that meets the criteria of Regulatory Guide 1.133.

A loose-parts monitoring program could provide an early detection of loose parts in the primary system that could help prevent damage to the primary system. Such damage relates primarily to

(1) damage to fuel cladding resulting from reheating or mechanical penetration

(2) jamming of control rods

(3) possible degradation of the component that is the source of the loose part to a level such that it cannot properly perform its safety-related function

Backfitting of a loose-parts monitoring program is being considered in Revision 1 to Regulatory Guide 1.133. If the staff decides to implement the recommendations of this revision, then the need to implement a loose-parts monitoring program on operating reactors will be addressed generically.

The following factors were considered in making a recommendation that no backfitting be done at this time:

(1) A summary of 31 representative loose-parts incidents at 31 reactors (from the value-impact statement of Revision 1 to Regulatory Guide 1.133) indicates that structural damage occurred as a result of loose parts in only nine incidents. None of these incidents caused a safety-related accident.

(2) Most loose parts can be detected during refueling inspections.

(3) The limited PRA of this issue for Millstone Unit 1 concluded that eliminating loose parts-induced transients by installing a loose-parts monitoring system would have no effect on risk.

Backfitting, therefore, is not recommended.

4.14 Topic III-10.A, Thermal-Overload Protection for Motors of Motor-Operated Valves

10 CFR 50.55a(h), as implemented by Institute of Electrical and Electronics Engineers (IEEE) Std. 279-1971 and 10 CFR 50 (GDC 13, 21, 22, 23, and 29), requires that protective actions be reliable and precise and that they satisfy the single-failure criterion using quality components. Regulatory Guide 1.106 presents the staff position on how thermal-overload protection devices can be made to meet these requirements.

The objective of this review is to provide assurance that the application of thermal-overload protection devices to motors associated with safety-related motor-operated valves (MOVs) does not result in needless hindrance of the valves' performance of their safety functions.

In accordance with this objective, the application of either one of the two recommendations contained in Regulatory Guide 1.106 is adequate. These recommendations are as follows:

(1) Provided that the completion of the safety function is not jeopardized or that other safety systems are not degraded

    (a) the thermal-overload protection devices should be continuously bypassed and temporarily functional only when the valve motors are undergoing periodic or maintenance testing, or

    (b) those thermal-overload protection devices that are normally functional during plant operation should be bypassed under accident conditions.

(2) The trip setpoint of the thermal-overload protection devices should be established with all uncertainties resolved in favor of completing the safety-related action. With respect to those uncertainties, consideration should be given to

    (a) variations in the ambient temperature at the installed location of the overload protection devices and the valve motors

    (b) inaccuracies in motor heating data and the overload protection device trip characteristics and the matching of these two items

    (c) setpoint drift

    To ensure continued functional reliability and the accuracy of the trip setpoint, the thermal-overload protection device should be tested periodically.

In Millstone Unit 1, of 59 safety-related MOVs, 12 are not normally in their emergency position and have thermal-overload protection devices that are not bypassed by an emergency signal; nor has it been shown that their trip setpoints were conservatively set.

The limited PRA of this issue for Millstone Unit 1 concluded that a single valve will have its unavailability reduced by 14%. Only two of the valves that do not have their thermal overload protection devices bypassed were evaluated in the Millstone Unit 1 IREP and limited PRA. The failure probabilities of these two valves were reduced and the dominant core-melt sequences from the Millstone IREP were calculated for the limited PRA. The results indicated that bypassing the thermal overload protection made a minor (<1%) change in overall core-melt frequency. The PRA concluded that reduction in a component unavailability affects half of the dominant sequences but the effect on each sequence is small.

Because only 2 valves were considered in the limited PRA and 12 valves are deficient and because multiple valve failures were not considered, the staff concludes that the position taken in its letter dated April 12, 1982 is still valid. In that letter, the staff requested the licensee to (1) demonstrate that the proper thermal-overload protection devices have been selected and that their trip setpoints have been conservatively set and (2) summarize the operating experience of each of the 12 valves. The licensee has agreed with the staff's position and will provide an analysis of trip setpoints by January 3, 1983 and where necessary will modify or bypass thermal overload protection devices before startup from the 1984 refueling outage.

4.15 Topic IV-2, Reactivity Control Systems, Including Functional Design and Protection Against Single Failures

10 CFR 50 (GDC 2), as implemented by SRP Section 7.7, requires that the reactor protection system be designed to ensure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems. A preliminary PRA of the effects of multiple rod withdrawal on risk demonstrated that this issue is of low importance because (1) the single failures identified do not affect the ability of the scram function and (2) the limited exceedance of the fuel thermal limits is not significant to risk. All significant risk sequences involve core melt, and the issue of multiple rod withdrawal does not affect core-melt probability.

During the topic review, sufficient information was not available for the staff to complete a single-failure analysis of the rod control system. On the basis of the review of Dresden Unit 2, specific types of rod motion from postulated single failures were identified for Millstone Unit 1. These were used in the core analysis of Topic XV-8, "Control Rod Misoperation." On the basis of the assumed rod motions, it was determined that the Millstone Unit 1 design meets current licensing criteria. By letter dated October 14, 1982, the licensee provided additional information on the design of the Millstone Unit 1 rod control system and the effect of single failures. On the basis of the considerations described above and in that letter, the staff concludes that the types of rod motions assumed in SEP Topic XV-8 are bounding rod motions. Since the consequences of such rod motions have been found acceptable, the staff considers this topic adequately resolved.

4.16 Topic V-5, Reactor Coolant Pressure Boundary (RCPB) Leakage Detection

10 CFR 50 (GDC 30), as implemented by Regulatory Guide 1.45 and SRP Section 5.2.5, prescribes the types and sensitivity of systems and their seismic, indication, and testability criteria necessary to detect leakage of primary reactor coolant to the containment or to other interconnected systems. Regulatory Guide 1.45 recommends that at least three separate leak detection systems be installed in a nuclear power plant to detect unidentified leakage from the RCPB to the primary containment of 1 gpm within 1 hour. Leakage from identified sources must be isolated so that the flow of this leakage may be monitored separately from unidentified leakage. The detection systems should be capable of performing their functions after certain seismic events and being checked in the control room. Of the three separate leak detection methods recommended, two of the methods should be (1) sump level and flow monitoring and (2) airborne particulate radioactivity monitoring. The third method may be either monitoring the condensate flow rate from air coolers or monitoring airborne gaseous radioactivity. Other detection methods--such as monitoring humidity, temperature, or pressure--should be considered to be indirect indications of leakage to the containment. In addition, provisions should be made to

monitor systems that interface with the RCPB for signs of intersystem leakage through methods such as monitoring radioactivity and water levels or flow.

A limited risk assessment of the importance of the sensitivity of leakage detection systems to risk was performed. This study only addressed leakage detection as it related to the small-break LOCA. For this event, it was determined that the importance of leak detection capability (i.e., the sensitivity of detectors to leak rate and time) to risk was very dependent on time for a leak to become a break. If the leak-before-break-time was short (less than 1 hour, current requirement for detection of 1 gpm) or long (more than 8 hours to detect a 1-gpm leak), the benefits of leak detection capability were low. However, this limited risk assessment does not address the staff's principal concern with respect to leakage detection, which is not the small-break LOCA event but BWR pipe cracks and the effects of a high energy pipe break (HEPB) inside containment. Millstone 1 was not originally designed to mitigate the effects of a HEPB (e.g., pipe whip, jet impingement, and cascading breaks). There are no physical restraints, and there may not be adequate separation between systems. Therefore, a HEPB may cause damage in other systems and may reduce the availability of mitigating systems. This aspect has not been evaluated in either the Millstone Unit 1 or Browns Ferry (NUREG/CR-2802) IREP studies (nor in any other PRA).

For example, plant-specific evaluations of crack size and leak rates for the emergency condenser inlet and return lines at Oyster Creek have shown that a leakage detection capability with a sensitivity of 0.1 to 1.0 gpm is necessary to detect a through-wall circumferential flaw that is four times the pipe wall thickness (e.g., approximately 3.5 in. long for a 16-in.-diameter pipe). These flow rates are predicted by analyses based on elastic-plastic fracture mechanics that have been verified on a limited basis by experimental data. Experience has shown that the sensitivity and reliability of current leakage detection equipment may be questionable (e.g., Duane Arnold safe-end cracks and Indian Point Unit 2 fan cooler leakage). Further, most crack growth processes (e.g., fatigue and stress corrosion) are time dependent, yet experience has shown that it is almost impossible to quantify the rates (e.g., rates of hours to months have been experienced). However, time to achieve the required sensitivity is important because the exposure times for transient loadings are increased and, thus, the potential for unstable failure is increased.

For some postulated break locations, where separation and/or restraint is not practical or possible to mitigate the effects of an HEPB, it may be necessary to utilize local leak detection. The current licensing position of detection of a leak of 1 gpm within 1 hour may not be sufficient for consideration of some HEPB locations.

It is the staff's position that leakage detection systems and sensitivity should be reviewed in conjunction with "Effects of Pipe Breaks on Structures, Systems, and Components Inside Containment" (Topic III-5.A) in Section 4.9.

4.16.1 Systems Currently Available at Millstone Unit 1

The licensee currently determines reactor coolant pressure boundary leakage by monitoring the drywell sump and measurement of quantity of water transferred out of the sump. The sump is pumped once every shift, and the volume transferred is averaged over the time elapsed since the previous pumping. The licensee believes, on the basis of experience, that leaks of 1 gpm can be detected by this method. The sump is also equipped with an alarm that activates when the Technical Specification limiting condition for operation of 2.5 gpm into the sump is achieved. The licensee believes that this method provides adequate leak detection capability.

(1) <u>System Sensitivity</u>

The existing system at Millstone Unit 1 is capable of detecting a 1-gpm leak in less than 8 hours (depending on frequency of pumping the sump) but does not meet the current licensing requirement of being able to detect a leak of 1 gpm in 1 hour.

(2) <u>Seismic Qualification</u>

Seismic qualification of the current system has not been addressed by the licensee. The topic SER did not find this system to be seismically qualified. Current requirements state that the airborne particulate monitor should be qualified to the safe shutdown earthquake (SSE), the other two methods should be qualified to the operating-basis earthquake (OBE).

(3) <u>Testability</u>

The current practice of pumping the sump and recording the amounts every shift ensures sump pump and level monitoring operability. Therefore, the staff concludes that current operating practice meets the intent of the system testability requirements.

(4) <u>Number of Systems</u>

Currently, the licensee has only one system. Current criteria require three.

(5) <u>Operability Requirements</u>

The Millstone Unit 1 Technical Specifications do not contain limiting conditions for operation or surveillance requirements regarding the operability of leakage detection systems, as recommended by Regulatory Guide 1.45 and the BWR Standard Technical Specifications (NUREG-0123). It is the staff's position that such specifications are necessary to ensure operability and therefore timely detection of leakage from the reactor coolant system.

It is the staff's position that

(1) The licensee should provide a seismically qualified (SSE) method for determining RCPB leakage.

(2) The method should be testable during operation.

(3) The licensee should evaluate leakage detection sensitivity requirements in conjunction with the resolution of Topic III-5.A for the purpose of establishing appropriate limiting conditions for operation.

The licensee has agreed to address the staff's position in conjunction with the resolution of Topic III-5.A (Section 4.9).

4.16.2 Intersystem Leakage

During the topic review, information concerning the leakage detection systems for intersystem RCPB leakage was incomplete. PRA results for Dresden Unit 2 and Oyster Creek have shown that intersystem leakage is not a significant contributor to overall risk. The closed cooling water (CCW) system at Millstone Unit 1 operates at a higher pressure than the service water system so that leakage would be to the environment. There are activity monitors on the CCW system and effluent monitors that would identify such leakage so that corrective action could be taken. Therefore, backfitting is not recommended.

4.17 Topic V-10.B, Residual Heat Removal System Reliability

10 CFR 50 (GDC 19 and 34), as implemented by SRP Section 5.4.7, BTP RSB 5-1, and Regulatory Guide 1.139, requires that the plant can be taken from normal operating conditions to cold shutdown using only safety-grade systems, assuming a single failure and using either onsite or offsite power through the use of suitable procedures.

The existing procedures at Millstone Unit 1 were evaluated during the IREP study of the plant. Using the human factors techniques of the IREP study, the results showed that the Millstone procedures concerning instructions to the operator were sufficient, and human error in initiating alternate cooldown methods did not contribute to risk during the residual heat removal phase of cooldown. It did, however, contribute to risk from early cooling failures resulting from the probability of operator failure to manually depressurize when high-pressure cooling was unavailable and, therefore, low-pressure makeup was required. This failure was the result of a poorly structured procedure, which did include the action described above.

The limited PRA of this topic concluded that the dominant part of the risk is involved with achieving hot shutdown and, therefore, did not consider achieving cold shutdown. The PRA concluded that achieving cold shutdown had no impact on core-melt frequency.

It should be noted that in response to NUREG-0737, Item I.C.1, "Guidance for the Evaluation and Development of Procedures for Transients and Accidents," the licensee is implementing the generic, symptom-oriented emergency procedural guidelines developed through the BWR Owners Group. The procedural guidelines were submitted to the staff by a letter from T. J. Dente to D. G. Eisenhut dated June 8, 1982.

In regard to procedures for conducting a plant cooldown to cold shutdown from outside the control room, the licensee has proposed to revise the existing procedures for shutdown from outside the control room to include steps to proceed to a cold shutdown condition.

The review and implementation of any required procedural changes for safe shutdown should be coordinated with other procedural changes (e.g., emergency procedures for flooding, Topic II.3.B, Section 4.1.6) and the BWR Owners Group generic emergency procedural guidelines. Implementation of revised procedures will be completed and reported to the NRC by the end of the 1984 refueling outage, following NRC approval of the generic emergency procedural guidelines. The staff finds this acceptable.

4.18 Topic V-11.A, Requirements for Isolation of High- and Low-Pressure Systems

10 CFR 50.55a, as implemented by SRP Section 7.6 and BTP ICSB 3, requires that the motor-operated valves (MOVs) used for the isolation of the reactor coolant system from other systems that have lower design pressure ratings should have independent and diverse interlocks. These interlocks should prevent the opening of the MOVs until the reactor coolant system (RCS) pressure is below the system design pressure, and close them automatically when RCS pressure increases above the system design pressure.

The reactor water cleanup (RWCU) system does not satisfy the current licensing requirements. Isolation on the suction side of the RWCU system is provided by three MOVs, an inboard valve (closest to the RCS), a pump suction valve, and a pump bypass valve. Isolation on the discharge side is provided by an MOV and one check valve. All the MOVs have position indication in the control room. None of the MOVs will open if pressure in the low-pressure portions of the system is higher than its design pressure. All the MOVs will close on high RWCU system temperature, low reactor water level, loss of control power, or high RWCU system pressure. The pressure interlocks for these valves use the same sensors and relays. Because the interlocks for the isolation valves are not independent, the staff has determined that Millstone Unit 1 does not comply with current licensing requirements.

The failure of the pressure interlock will lead to the overpressurization of the RWCU system. If the relief valve has enough capacity, the excess flow will be discharged to the torus. If the relief valve does not have enough capacity or if it fails to open, the system would break producing a LOCA outside containment.

The limited PRA for Millstone Unit 1 has shown that assuming the pressure relief valve is sufficiently sized, the frequency of an interfacing system LOCA through this system resulting in core melt is about 10^{-7}/year and the issue has low importance to risk; however, the large-break LOCA frequency is about 10^{-3}/year. No large-break-LOCA-initiated sequences appear as a dominant core-melt sequence for Millstone Unit 1.

It is the staff's position that the licensee either demonstrate the adequacy of the RWCU relief valve or install a redundant pressure sensor for actuation of system isolation on high pressure.

The licensee has proposed to install an independent pressure interlock for the inboard suction isolation valve by the spring of 1984. The staff finds this proposal acceptable.

4.19 Topic V-12.A, Water Purity of BWR Primary Coolant

10 CFR 50 (GDC 14), as implemented by Regulatory Guide 1.56, requires that the reactor coolant pressure boundary (RCPB) have minimal probability of rapidly propagating failure. This includes corrosion-induced failures from impurities in the reactor coolant system. The safety objective of this review is to ensure that the plant reactor coolant chemistry is adequately controlled to minimize the possibility of corrosion-induced failures. The staff's review identified the following two issues.

4.19.1 Water Chemistry Limits

Millstone Unit 1 Technical Specifications do not meet the limits established in Regulatory Guide 1.56 for conductivity and chlorides of the reactor vessel water and conductivity of the feedwater system.

The licensee has proposed to revise the existing Technical Specifications for chlorides and conductivity to be consistent with Regulatory Guide 1.56, or he will provide justification for not doing so. The revised Technical Specifications or the justification analysis mentioned above will be provided to the staff by February 1, 1983.

4.19.2 Limiting Conditions for Operation

The requirements of the plant operating procedures that govern (1) the sampling of the RWCU system demineralizer on service and subsequent shifting of flow if warranted and (2) the measurement of flow every 4 hours through each condensate demineralizer on service and the daily calculation of unused capacity of each bed are not incorporated into the plant Technical Specifications. These requirements are necessary to avoid corrosion-induced failures in case of a condenser tube rupture. The licensee should incorporate these requirements into the plant Technical Specifications or demonstrate that maintaining a minimum reserve capacity in the RWCU and condensate demineralizers is not necessary (other shutdown methods are available and there are procedures for their use in this case). The new proposed Technical Specifications or the demonstration described above will be provided to the staff by February 1, 1983.

4.20 Topic VI-4, Containment Isolation System

10 CFR 50 (GDC 54, 55, 56, and 57), as implemented by SRP Section 6.2.4 and Regulatory Guides 1.11 and 1.141, requires isolation provisions for the lines penetrating the primary containment to maintain an essentially leaktight barrier against the uncontrolled release of radioactivity to the environment. The staff review of the containment penetrations has identified several areas that do not conform to current licensing criteria for containment isolation. The staff recommends that backfitting not be required except for the establishment of administrative procedures to lock isolation valves in a closed position, providing leakage detection for certain lines, and installation of three drain valves to provide two-valve isolation.

The limited PRA results for Millstone Unit 1 have classified this issue as having low importance to risk. This is because the dominant contributor to risk is releases from core-melt accidents and not from releases from non-core-melt accidents. Since IREP concluded that a core melt would eventually cause an overpressure failure of the containment, there would be little benefit achieved by increasing the reliability of isolation of the containment.

On the basis of this conclusion, the staff has not recommended substantial physical modifications to the Millstone Unit 1 facility to comply with the GDC requirements. However, to provide adequate protection to minimize containment leakage following non-core-melt accidents, the staff has recommended the modifications described below.

4.20.1 Locked-Closed Valves

The valves listed below are either test, vent, drain, or sample line manual isolation valves that connect to piping penetrating the containment. The staff will require that these valves should have mechanical locking devices as required by GDC 55, 56, and 57 and appropriate administrative controls. The corresponding penetrations and lines are:

Penetration	Line	Valve number
X-9B	Testline off feedwater line	220-86B
X-12	Test line from reactor shutdown cooling supply	1001-6
X-14	Branch line from RWCU supply	1201-3
X-17	Test line from reactor head cooling	205-2-7(1-HS-8)
X-39A	Test line off containment spray	1501-25A(1-LP-42A)
X-39B	Test line off containment spray	1501-25B (1-LP-42B)
X-43	Test line off LPCI	1-LP-72A
X-45	Test line off LPCI	1-LP-72B
X-210B	Containment and core spray test line drain	Valve on line CS-4b (valve number unknown) 1-LP-67B 1-LP-68B 1-CS-32B 1-CS-35B
X-211A	Vent or drain lines off containment pool spray line on line CC-26	1-1/2-in. valves(2) 1-LP-35A

Penetration	Line	Valve number
X-211B	Vent or drain lines off containment pool spray line on line CC-26	1-LP-37B 1-LP-38B 1-LP-36B

The licensee has agreed to lock close and administratively control these valves.

4.20.2 Lines Requiring a Second Valve and Both Locked Closed

These lines are either test, vent, drain, or sample lines that connect to piping penetrating the containment and are outside containment but before any isolation valve. These lines require a second valve and mechanical locking devices for both valves for which appropriate administrative controls should be provided. GDC 56 requires two isolation valves on lines that connect to containment atmosphere and penetrate primary containment. Valves shall be automatic or locked closed and administratively controlled. These lines, penetrations, and existing valves are:

Penetration	Line	Valve number
X-204	Branch line off LPCI suction line	2-in. drain valve on line CC-16 (valve number unknown)
X-210A	Containment and core spray test line drain	1-LP-67A
----	Torus drain	Valve number unknown

The licensee has not responded to the staff's position.

4.20.3 Remote Manual Valves

The containment spray (low-pressure coolant injection) and core spray systems are closed systems as defined in GDC 57; they are provided with remote manual isolation valves rather than automatic isolation valves. These systems serve an essential emergency core cooling system function and the staff agrees that automatic isolation valves should not be used. However, because operator action is required to initiate isolation, if necessary, the operator must know when to do so. This requires a leakage detection capability (e.g., sump alarms) and appropriate procedures to indicate under what conditions these valves should be shut. The operating station for these remotely operated valves must be accessible, but it need not be in the control room. It is the staff's position that adequate leakage detection and appropriate procedures for operator action should be demonstrated and the operating station be located in an accessible area, where necessary, for the valves given below with their corresponding penetrations and lines:

Penetration	Line	Valve number
X-204A X-204B X-204C	Containment and core spray inlet	1402-3A(CS-2A) 1402-3B(CS-2B) 1-LP-2A,B,C,D

Penetration	Line	Valve number
X-16A X-16B	Core spray outlet	1402-25A (1-CS-5A) 1402-25B (1-CS-5B)
X-24	RBCCW outlet	58-B
X-43	LPCI inlet	1501-29A(1-LP-10A
X-45	LPCI inlet	1501-29B(1-LP-10B)
X-211A X-211B	Containment pool spray	1501-37A(1-LP-14A) 1501-37B(1-LP-14B)
X-39	Containment spray	1501-26A,B(1-LP-69A,B) 1501-47A,B(1-LP-47A,B)
X-16	Core spray	CS-5A CS-5B

The licensee has agreed to this position.

4.20.4 Valve Location

The following systems have both isolation valves outside containment instead of one inside and one outside, as required by GDC 57:

System	Penetration	Valve number
Containment drywell spray	X-39	1501-26A,B(1-LP-16A,B) 1501-47A,B(1-LP-15A,B)
Containment pool spray	X-211	1501-37A,B(1-LP-14A,B) 1501-34A,B(1-LP-13,A,B)

The relative benefit of one valve inside and one valve outside rather than two valves outside containment was evaluated in the limited PRA for the Palisades Plant (see NUREG-0820, Appendix D). In this study, little improvement could be shown in moving a valve inside containment. This is because the probability of failure of both valves was greater than the probability of failure of the pipe between the containment and first isolation valve. Because of the minimum improvement in containment isolation capability and low importance of leakage to overall risk, backfitting is not recommended.

4.20.5 Instrument Lines

The following systems use local manual isolating valves and excess flow check valves outside the containment:

System	Penetration
(1) Torus level	X-206
(2) Reactor protection system	X-27 through X-35 and X-49
(3) Instrument lines	X-40 and X-44

Valves associated with Items (2) and (3) above have a manual globe valve in series with an excess flow check valve; valves associated with Item (1) do not include an excess flow check valve. The staff concludes that since valves associated with Items (2) and (3) above are associated with engineered safety features systems, a single excess flow check valve provides adequate isolation.

The staff concludes that local manual valves for the torus level monitoring should be accepted for the following reasons:

(1) These lines monitor essential containment parameters that should not be automatically isolated. Any logic circuit that would automatically isolate these lines could introduce spurious isolation and cause the loss of vital safety information.

(2) Several risks assessments have shown that containment leakage from small penetrations is of low importance to risk.

Backfitting is, therefore, not recommended.

4.20.6 Valve Location and Type

The following lines use check valves in series instead of a check valve inside and a remote manual valve outside the drywell for containment isolation as required by GDC 55 and 56. These lines and associated penetrations and valves are:

Penetration	Line	Valve number
X-9A	Feedwater	220-62A (FW-9A)
X-9B	Feedwater	220-62B (FW-9B)
X-42	Standby liquid control	1101-16 (SL-7)
X-210A X-210B	Containment and core spray test line	V-10-18A(CS-14A) V-10-18B(CS-14B)
X-212	RWCU vent	Number unknown
X-23	RBCCW inlet	V-4-60

The feedwater system supplies the reactor through two parallel 18-in. lines, each containing two check valves in series (one inside and one outside containment). Remote manual isolation valves exist (in the turbine building) at the discharge end of each high-pressure heater stage (three units in parallel).

For the following reasons, replacing a feedwater check valve with a remote manual isolation valve or adding a remote manual isolation valve outside containment is not recommended:

(1) The high-pressure heater discharge valves provide backup isolation capability.

(2) The existing feedwater check valves are subject to local leakage rate tests, in accordance with 10 CFR 50, Appendix J.

(3) The isolation reliability would not be significantly improved by adding a remote manual valve.

Because the core spray system is a closed-loop ESF system that functions during accident conditions, it is considered an extension of the containment boundary. The check valves are in the minimum flow recirculation lines of the containment spray pump. Therefore, the check valves do not provide any containment isolation function while the system is running. When the containment spray pump is idle, the check valves will isolate the torus from the rest of the containment spray system. Because the maximum torus pressure is low and the core spray system is designed to withstand the design seismic event, piping failure is not likely. Backfitting is not recommended.

A 20-in. check valve is in the cleanup demineralizer system discharge line of a safety relief valve leading to the torus. A check valve in this line is necessary to ensure that the overpressure relief protection is not defeated. The check valve and relief valve (reverse direction) in series with relatively low system pressures (less than 100 psig) provide adequate assurance of containment isolation. Therefore, backfitting is not recommended.

A 1-1/2-in. regulating flow check valve is relied on as an isolation valve in the line connecting the standby liquid control tank to the reactor. The system, which is an ESF system, is intended for use should the control rod drive system fail. Therefore, it serves an essential function and should not be replaced with automatic valves. There are two valves in parallel with the check valve that are located upstream from the check valve. These valves are explosive valves, which are normally closed and which require explicit operator action to open. Although not considered isolation valves, they do provide added isolation capability. System reliability would be decreased by adding a remote manual valve; therefore, the staff finds the current isolation capability acceptable.

4.20.7 Lack of Information

There are two penetrations with branch lines off the main lines that require isolation and for which the isolation capability is unknown. These penetrations and lines are:

Penetration	Line
X-211A	Reactor coolant sample return line connected to line CC-26

Penetration	Line
X-204	Cooling water return lines (2) that branch off in between takeoffs to containment spray pumps

It is the staff's position that the licensee review the isolation capability of these lines as required by the GDCs and either implement modifications or demonstrate that adequate isolation capability exists.

The licensee has not yet formally responded to the staff's position. However, during the October 26, 1982 ACRS Subcommittee meeting, the licensee agreed with this position.

4.21 Topic VI-7.A.3, Emergency Core Cooling System Actuation System

10 CFR 50.55a(h), as implemented by IEEE Std. 279-1971, and 10 CFR 50 Appendix A (GDC 37), as implemented by Regulatory Guide 1.22, require that equipment important to safety be tested periodically to ensure the operability of the system as a whole and to verify, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation, including the operation of the associated cooling water system.

During the staff review the following issues have been identified:

4.21.1 Testing of Space Coolers

At Millstone Unit 1, the unit Technical Specifications do not require the testing of the core spray system pump space coolers, which are part of the turbine building secondary closed cooling water system (cooled by the service water system).

The licensee states that the space coolers, which cool the corner rooms in the reactor building, are not essential; therefore, their testing is not required. The licensee will provide the staff with information to substantiate this conclusion by November 30, 1982.

4.21.2 Testing of the Emergency Service Water System

The test of the LPCI system does not demonstrate that the station emergency service water system (ESWS), which provides cooling to the LPCI system heat exchangers, will start when the LPCI is initiated.

The licensee has indicated that since the ESWS is manually initiated by the operator, the LPCI test should not require that the ESWS also be initiated. However, the issues of appropriate ESWS testing and the existence of enough time and information for the manual start of the system have to be discussed.

In the case of a LOCA, heat is transfered from containment via the LPCI system by using sea water through the ESWS from the Long Island Sound. The containment cooling function is performed with the LPCI system after the core is flooded. This is accomplished within a few minutes for even the largest line break. Two of the three LPCI pumps can then be shut down, and two of the four containment cooling emergency ESWS pumps can be started manually to provide cooling water to one of the two heat exchangers. Suppression pool water can then be diverted to either of two cooling modes: containment spray cooling or suppression chamber cooling.

Technical Specification 3/4-5.B establishes limiting conditions for operation and surveillance requirements of the ESWS to maintain a high system availability. Station Procedure SP623.19, "Emergency Service Water System Operational Readiness Test," addresses the testing requirements required by the Technical Specifications.

Station Procedure OP506, "Loss of Coolant," directs the operator to place the ESWS in operation, in accordance with Operating Procedure 322, when the suppression chamber temperature approaches 90°F and plant load conditions permit. According to IREP LOCA Sequence 2 (the containment heat removal fails and all other functions succeed), the operator will have about 20 hours to start the containment heat removal function, that is, start the ESWS, to avoid containment overpressure.

The limited PRA of this topic concluded that operator errors in initiating the ESWS did not contribute to any dominant sequences and thus no reduction in core-melt frequency will be attained from installing automatic actuation of the ESWS.

Since the ESWS is periodically tested and the operator will have enough time and information to start the system manually when needed, the staff finds the actual design acceptable.

4.22 Topic VI-7.A.4, Core Spray Nozzle Effectiveness

10 CFR 50.46 requires that each boiling water reactor shall be provided with an emergency core cooling system designed to provide adequate cooling of the nuclear fuel under postulated accident conditions. Appendix K to 10 CFR 50, "ECCS Evaluation Models," sets forth the required and acceptable factors of the evaluation models. Information derived from Japanese core spray tests suggested that the central fuel bundles of a BWR/3 core may receive low core spray flow. Millstone Unit 1 is a BWR/3 plant. The staff is reviewing this concern independently of the SEP as a matter related to Generic Issue A-16, "Steam Effects on BWR Core Spray Distribution." The staff has evaluated the related information and has concluded that the Japanese data do not provide a basis for changing its conclusion that core spray flows for a BWR/3 are not less than the minimum flow required for core spray heat transfer. Therefore, the staff has concluded that no further SEP action is necessary for the following reasons:

(1) The Japanese data for a BWR/5 may be applicable only to a BWR/4 and a BWR/5 because they have a similar spray nozzle design. The BWR/3 spray nozzle design is different from BWR/4 or BWR/5 designs.

(2) Even though there are no core spray test data in a steam condition for a BWR/3 configuration, a BWR/6 30° sector steam test and 360° full-scale tests in an air environment performed in the United States indicate that the core spray overlaps the center bundles causing high flow rate over the central region of the core. As a result, flow to each bundle is not less than the minimum spray flow required for core spray heat transfer.

(3) GE has informed the staff that GE analyses show that for limiting cases of a BWR/3 with core spray assumed to flow down peripheral channels to increase the reflood rate (as observed in the Lynn test), the calculated peak clad temperature did not exceed the 10 CFR 50.46 limit of 2200°F with no credit taken for the spray cooling effect. The staff has requested GE to submit these analyses for its review.

4.23 Topic VI-7.C.1, Appendix K - Electrical Instrumentation and Control Re-Reviews

10 CFR 50 (GDC, 2, 4, 17, and 18), as implemented by SRP Sections 8.2 and 8.3 and Regulatory Guide 1.6, requires that redundant load groups and the redundant standby electrical power sources be independent at least to the following extent:

(1) No provisions should exist for automatically connecting one load group to another load group.

(2) No provisions should exist for automatically transferring loads between redundant power sources.

(3) If means exist for manually connecting redundant load groups together, at least one interlock should be provided to prevent an operator error that would parallel their standby power sources.

The reasons for these requirements include the following:

(1) There is evidence based on operating experience and analytical considerations that the parallel operation of standby power sources renders them vulnerable to common-mode failures. Current designs are therefore based on the concept of independent, redundant load groups. In these designs, the standby power source for one load group is never automatically interconnected under accident conditions with the standby power source of a redundant counterpart.

(2) There can be compromises of independence resulting from automatic bus ties that connect the loads of one load group to the power source of another in the event the power source of the first load group has failed. The slightly improved defense against random failures achieved by these bus ties is more than offset by the additional vulnerability to common-mode failures that they create.

The limited PRA of Millstone Unit 1 for this topic was performed in conjunction with SEP Topic VII-3. The issue in SEP Topic VII-3 relates to the existence of a single instrument ac bus instead of redundant buses so that the failure of this single bus may result in the loss of essential instrumentation or controls needed to reach safe shutdown. Although not identified in the SEP topic list, the PRA review concluded that because of the interrelationship of the instrument ac bus and the vital ac power source, diverse instrumentation and vital ac power systems were considered along with the removal of the automatic bus transfers (ABTs) in the remainder of the ac power system (480-V ac bus transfers) and the removal of all dc system manual bus transfers. The PRA concluded that the above changes resulted in a reduction in core-melt frequency of 10% with a corresponding reduction in risk of 14%. The dominant contributor to this risk reduction was redesign of the instrument ac power system to provide redundant instrument ac buses. Redesign of the vital ac power system to make it more reliable and removal of the ABTs had no impact on risk. Removal of the ABTs alone may increase risk because the instrumentation system was subject to the failure of the remaining power supply. (Implicit in the removal of an ABT is the requirement to provide redundant trains of safety equipment.

During the staff's review the following issues were identified.

4.23.1 Automatic Bus Transfers

Buses 2A-3NE, 2-3NE, and 22A-1, the 120-V ac instrument bus IAC-1, and the 120-V ac vital bus VAC-1 are supplied from automatic transfer switches that can transfer loads between redundant sources.

The licensee has proposed to evaluate the existing ABTs and identify any necessary corrective actions by November 30, 1982.

4.23.2 Manual Bus Transfers

The 125-V dc system has three load centers that are manually transferred between redundant sources under administrative control; however, there are no interlocks to prevent an operator error that would parallel the emergency power sources.

The lack of appropriate interlocks renders redundant dc sources vulnerable to common-mode failure; therefore, it is the staff's position that appropriate interlocks be installed or justification for not doing so be provided by the licensee.

The licensee has proposed to evaluate the existing manual transfers and identify any necessary corrective actions by November 30, 1982.

4.24 Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

10 CFR 50 (GDC 21), as implemented by Regulatory Guide 1.22 and the Standard Technical Specifications (STS)(NUREG-0123), requires that the reactor protection system be designed to permit periodic testing of its functioning, including a capability to test channels independently.

10 CFR 50.55aa(h), through IEEE Std. 279-1971 and IEEE Std. 338-1977, requires that response-time testing be performed on a periodic basis for plants with construction permits issued after January 1, 1971.

During the staff review, the following issues have been identified.

4.24.1 Surveillance Frequency

For the reactor trip system at Millstone, three signals (average power range monitor (APRM)-flow biased high flux, APRM-reduced high flux, and intermediate range monitor (IRM)) are not subjected to a channel check as frequently as required, one signal (high steam line radiation) is not subjected to a channel functional test as frequently as required, and one channel (APRM-reduced high flux) is not calibrated as frequently as required.

The limited PRA of this topic was performed using the test frequencies currently performed at Millstone Unit 1, regardless of what the Technical Specifications call for. For the above signals, the PRA was performed using existing test frequencies at Millstone Unit 1 and concluded that these system components did not contribute to the dominant failure mechanisms of the reactor protection system (RPS). Rather, the RPS failure probability is dominated by common-mode mechanical failures. The PRA did conclude, however, that the increased testing required by the STS as compared with Millstone Unit 1 testing procedures would lower the failure probabilities of the affected instrumentation.

The staff requires that the the Technical Specifications be upgraded to meet the requirements of the STS regarding channel check frequency of the APRM-flow biased high flux and IRM.

The licensee disagrees with this position.

The high steam line radiation signal had to be subjected to a weekly channel functional test according to the STS (NUREG-0123), Revision 2. The new STS, Revision 3, requires a monthly test as is actually required by the Millstone Unit 1 Technical Specifications. Therefore, no modifications are needed.

The licensee has indicated that the APRM-reduced high-flux channel is unique to Millstone Unit 1 because of its capability to withstand a full-load rejection without having to scram the reactor and, therefore, is not covered by the STS. The staff agrees that the STS does not include specific requirements for the surveillance of this channel; however, Millstone Unit 1 Technical Specifications recognize that "In order to assure adequate core margin during full load rejections in the event of failure of the selected rod insert, it is necessary to reduce the APRM scram trip setting to 90% of rated power following a full load rejection incident"; therefore, it is the staff's postition that the licensee should survey this channel as frequently as required for other APRM channels.

The licensee disagrees with this position.

4.24.2 Channel Functional Test Frequency

For the following channels, a channel functional test is required to be performed monthly by plant Technical Specifications. The Technical Specifications allow reduction to a quarterly test frequency, provided a certain level of satisfactory operational reliability is achieved; however, the licensee has not yet exercised this option.

(1) high reactor pressure
(2) high drywell pressure
(3) low reactor water level
(4) high water level in scram discharge
(5) main steam line isolation valve closure
(6) turbine stop valves closure
(7) manual scram
(8) turbine control valves fast closure
(9) APRM-flow biased high flux

As stated earlier, the PRA for Millstone Unit 1 was performed using the test frequencies currently performed. Because the test frequencies required by the STS currently agree with test frequencies required by Millstone Technical Specifications, there is no effect on risk of implementing the STS. Should the actual testing frequencies decrease (e.g., quarterly versus monthly testing) as allowed by Millstone Unit 1 Technical Specifications, the risk analysis for Millstone Unit 1 would change.

It is the staff's position that the option of increasing the test interval to quarterly should be deleted from the Millstone Unit 1 Technical Specifications so that the testing frequency is consistent with GE Standard Technical Specifications.

The licensee disagrees with this position.

4.24.3 Response-Time Testing

In the Millstone Unit 1 Technical Specifications, the channel response time between channel trip and the deenergization of the scram relay is not required to be tested. Although the channel response time between channel trip and deenergization of the scram relay is not required to be tested, there is assurance that this time would be within the Technical Specifications limit. The time from initiation of any channel trip, which is the time a GE type of HFA relay is deenergized, to the deenergization of the scram relay, which is the time the HFA relay contacts open, is given by the manufacturer as less than or equal to 14 msec. The licensee submitted a Technical Specification change request by letter dated September 9, 1980, to change the required response time from 100 to 50 msec. To support this change, the licensee conducted tests on a number of channels that determined the response times to be well below 50 msec. This change was approved by the NRC by Amendment 78 to the license, dated September 8, 1981. The staff performed a limited PRA of this issue for Millstone Unit 1 to estimate the improvement in overall safety if response-time testing of the reactor protection system (RPS) was required. The results of this PRA indicated that response-time testing has low safety significance. This occurs because response-time testing is concerned with events on the order of seconds and the PRA has shown that response times of minutes are sufficient, for the RPS actuation, to ensure the success of the subcriticality function in time to allow other safety systems to prevent core melt. Functional tests are sufficient to demonstrate function on the order of minutes, and these tests are performed at Millstone Unit 1. Therefore, it is the staff's judgment that response-time testing of the RPS should not be required.

4.25 Topic VII-1.A, Isolation of Reactor Protection System From Nonsafety Systems, Including Qualifications of Isolation Devices

10 CFR 50.55a(h), through IEEE Std. 279-1971, requires that safety signals be isolated from nonsafety signals and that no credible failure at the output of an isolation device shall prevent the associated protection system channel from meeting the minimum performance requirements specified in the design bases.

During the staff review, the following issues have been identified.

4.25.1 Isolation Between Reactor Protection System and Monitoring Systems

At Millstone Unit 1, there are no isolation devices between the nuclear flux monitoring systems and the process recorders and indicating instruments, nor are there any between the APRM system and process computer.

The limited PRA of these issues performed for Millstone Unit 1 concluded that there is no change in system unavailability resulting from the above failures; failure of the RPS was still dominated by common-mode mechanical faults. However, it is the staff's position that the potential existence of common-mode electrical faults should be evaluated.

The licensee has proposed to conduct tests to determine if adequate isolation exists between (1) the nuclear flux monitoring system and the process recorders and indicating instruments and (2) the APRM system and the process computer. The licensee will inform the staff of the results of these tests and any required corrective action by December 29, 1982. The staff finds this proposal acceptable.

4.25.2 Isolation Between the Reactor Protection System and its Power Supply

Isolation between each reactor protection system channel and its respective power supply is inadequate because failures of the motor-generator control system (abnormal voltage or frequency) could result in failure of an RPS channel to perform on demand.

The licensee has proposed to correct this deficiency during the present refueling outage. The staff finds this acceptable.

4.26 Topic VII-3, Systems Required for Safe Shutdown

10 CFR 50, Appendix A (GDC 13), as implemented by SRP 7.4 and Regulatory Guide 1.53, requires that the instrumentation necessary for reaching and maintaining cold shutdown conditions meets the single-failure criterion.

The staff's review of Millstone Unit 1 concluded that the loss of the instrumentation ac (IAC) bus would result in loss of indication in the control room of flow, temperature, level, and/or pressure of the systems required to shut down the reactor and/or maintain the reactor in a shutdown condition.

The effects of failure of the IAC bus on the availability to achieve and maintain a safe shutdown condition have been addressed previously in the licensee's response, dated February 29, 1980, to IE Bulletin 79-27, "Loss of Non-Class IE Instrumentation and Control Power System Bus During Operation." Because of the presence of local, direct-reading indications of vital parameters (such as reactor pressure and water level and isolation condenser shell side level), it was the licensee's determination that sufficient instrumentation would be available to achieve and maintain a safe shutdown condition following loss of the IAC bus.

The results of the PRA have been discussed in Section 4.23. The PRA concludes that removal of the ABTs and redesign of existing instrument and vital ac power systems results in a 10% reduction in core-melt frequency and a 14% reduction in risk.

Although the staff has not completed the review of the licensee's response to IE Bulletin 79-27, the review of those parts related to SEP Topic VII-3 with respect to loss of control room instrumentation has been performed and found to meet current licensing criteria for operating plants. The staff is currently reviewing the PRA results in detail to determine if a single vital instrument bus for control room indication with credit for shutdown from outside the control room should be modified.

4.27 Topic VIII-1.A Potential Equipment Failures Associated With Degraded Grid Voltage

10 CFR 50 (GDC 17) requires an onsite and offsite electric power system to provide functioning of systems and components important to safety. The topic is being evaluated generically through multiplant actions (MPAs) B-23, "Degraded Grid Voltage Protection for Class 1E Power Systems," and B-48, "Adequacy of Station Electrical Distribution Voltages."

The purpose of this topic is to ensure that a degradation of the offsite power system will not result in the loss of capability of redundant safety-related equipment and to determine the susceptibility of such equipment to the interaction of onsite and offsite emergency power sources. The resolution of MPAs B-23 and B-48 will satisfy the requirements of this SEP topic. The purpose of MPA B-23 is to determine the grid characteristics and to provide a suitable system to isolate the plant from the grid in the event of grid voltage degradation. The purpose of MPA B-48 is to determine the minimum acceptable bus conditions that will then define the setpoint for the degraded grid protection system.

The staff's Safety Evaluation Report for MPA B-23 for Millstone Unit 1 was forwarded to the licensee by letter dated June 23, 1982. In that letter, the staff found the proposed modification to provide automatic separation of the Class 1E buses from a degraded offsite power source under accident conditions acceptable. Also, the licensee's proposal to modify the isolation condenser system to make it independent of ac power was found acceptable by the staff.

Under nonaccident conditions, however, a degraded grid voltage condition requires operator actions to protect the Class 1E systems. The staff proposed that operating procedures be developed to handle such situations and recommended that these procedures be reviewed during the SEP integrated assessment of the facility. These procedures are directly related to the staff's evaluation of SEP Topic VII-3, "Systems Required for Safe Shutdown." The staff has concluded that sufficient time and appropriate alarms and indications are available so that operator action is acceptable. Such actions would include starting the diesel generator or gas turbine to provide adequate voltage to vital equipment. It is the staff's position that these procedure modifications be coordinated with procedure modifications for Topic V-10.B (Section 4.17).

The licensee has agreed to develop operating procedures for a degraded voltage event to ensure that damage to safety-related equipment does not occur.

4.28 Topic VIII-2, Onsite Emergency Power Systems (Diesel Generator)

10 CFR 50 (GDC 17), as implemented by SRP Section 8.3.1 and BTP ICSB 17, requires that

(1) The design of standby diesel generator systems should retain only the engine overspeed and the generator differential trips and bypass all other trips under an accident condition.

(2) If other trips, in addition to the engine overspeed and generator differential trips, are retained for accident conditions, an acceptable design should provide two or more independent measurements of each of these trip parameters. Trip logic should be such that a diesel generator trip would require specific coincident logic.

In addition, GDC 17, as implemented by IEEE Std. 279-1971, requires that all the conditions that might render the emergency power generator incapable of automatic starting shall be unambiguously annunciated in the control room.

All current licensing criteria for emergency onsite power are directed to a diesel generator. At Millstone Unit 1, one of the two emergency onsite generators is powered by a gas turbine. There are no staff criteria for a gas turbine generator.

The gas turbine is rated at 10,000 kW continuous load and 11,500 kW peak load (compared with 2,700-kW base load and a 2-hour emergency load rated at 3,000 kW for the onsite diesel generator). This difference allows the gas turbine to power larger and more loads than the diesel generator; one of these loads is the emergency feedwater coolant injection system.

Because of the lack of specific licensing criteria for gas turbine generators as emergency power supplies in nuclear power plants, the staff has reviewed the Millstone Unit 1 gas turbine generator against the criteria for diesel generators and has identified the following issues.

4.28.1 Startup Trips

There are 17 trips that are not presently bypassed during emergency operation of the gas turbine generator. Four of the trips are associated with the startup of the gas turbine, six are associated with the steady-state operation of the gas turbine, and seven are associated with the output circuit breaker of the electric generator.

The four protective trips that are associated with startup are as follows:

(1) if light-off speed (930 rpm) is not reached in 20 sec (light-off speed is expected in 13 to 16 sec)

(2) if light-off temperature (400°F) is not reached 15 sec after lightoff (light-off temperature is expected 5 to 8 sec after reaching 930 rpm)

(3) if starting air-ignition cutoff speed (3,400 rpm) has not been reached 60 sec after start (expected 15 sec after light-off)

(4) if generator excitation speed (540 rpm electric-generator speed) is not reached in 60 sec (expected 35 sec after start)

These trips monitor a series of expected parameters during the starting sequence (i.e., turbine light-off). As stated in the topic evaluation, the actual operating time-delay settings allow for variations in performance of the applicable components and are set high enough to ensure a complete starting attempt and to preclude unnecessary shutdown of the system.

The licensee has proposed to bypass both the light-off speed and generator excitation speed trips under accident conditions. However, the light-off temperature and starting air-ignition cutoff speed trips should be retained in order to provide protection against a potential explosion. Both of these trips indicate a major problem on obtaining startup and are designed to trip the turbine and stop the fuel supply in order to prevent an explosion. An explosion could cause problems at the site in addition to the problems the site personnel would be trying to solve and thus compound the situation.

The staff agrees with the licensee's proposed corrective actions. The modifications will be implemented during the 1984 refueling outage.

4.28.2 Operational Trips

The six protective trips that are associated with the steady-state operation of the gas turbine generator are as follows:

(1) High Exhaust Gas Temperature - The trip for emergency operation is set at 1300°F, whereas, for normal power operation, it is set at 1200°F. It is anticipated that, for normal operation on a maximum ambient day (105°F), the exhaust gas temperature will not be in excess of 1050°F. For machine operation in the emergency mode on a maximum ambient day, the anticipated exhaust gas temperature is in the range of 1150°F to 1175°F. This gives a margin of 125°F to 150°F between this temperature range and the trip setting of 1300°F.

(2) High Lube Oil Temperature

(3) High Gas Generator Speed - This trip is set at 7,586 rpm, which represents a 3% overspeed condition for the emergency mode of operation. In the emergency mode of operation, because the breakers are closed and loading of the electrical generator starts at approximately 98% of synchronous speed, chances of a spurious gas generator overspeed excursion is very low. Any indications of overspeed would be indicative of a load rejection or governor failure in the gas generator.

(4) High Turbine Overspeed - 6,050 rpm

(5) High Vibration Jet

(6) Low Lube Oil Pressure - 14 lb

The licensee has proposed to bypass the high lube oil temperature trip under accident conditions; however, the remaining five trips are maintained, since each protects against severe mechanical damage and hazardous conditions. The licensee has stated that the high gas generator speed and high turbine overspeed trips are analogous to engine overspeed on a diesel generator and are necessary to prevent overspeed failures. The high exhaust gas temperature trip protects the unit against melting of mechanical parts. The high vibration jet trip protects against total mechanical degradation of the gas turbine. Since high vibration in a high-speed rotating piece of equipment is indicative of a severe problem, this trip must be maintained to protect against destructive failure of the machine.

The licensee has stated that the specific temperature parameters are monitored by a number of thermocouples, which provide a high degree of reliability. Speed sensing is accomplished with a shaft-mounted tachometer. For all of the unbypassed trips, the addition of another channel to monitor critical parameters to provide coincident logic would not provide significant improvement in reliability because coincident logic modifications involve the starting sequence and normal operating circuits, potentially making the gas turbine generator less reliable.

The onsite power protective circuits an associated setpoints are intended, as described in Regulatory Guide 1.9, Revision 2, to protect the emergency onsite power unit and to prevent inaccurate signals that would unneccessarily shut down the unit. Regulatory Guide 1.9 states that engine overspeed and generator differential trips may be implemented by a single-channel trip; however, all other diesel generator protective trips should either be (1) implemented with two or more independent measurements with coincident logic required for trip actuation or (2) bypassed under accident conditions provided the operator has sufficient time to react appropriately to an abnormal diesel generator unit condition. As stated in the topic SER forwarded by letter dated June 3, 1981, precautions are taken in setting the trip points so that the possibility of a trip during accident conditions is minimized.

The licensee has reported a total of 31 gas turbine generator failures in the last 12 years (see Table 4.2). On the basis of descriptions of the failures, many of them were due to problems associated with the speed switch in the early 1970s. In 1979, the licensee replaced the speed switch and governor. There were no failures reported in 1980. Since 1981, most failures were caused by rust on resistors and in the air pressure system. Because of these failures, the licensee is in the process of replacing the carbon steel lines with stainless steel lines and painting the inside of the air tank. In almost all cases when a failure of the generator occurred, it occurred because of an actual component failure and not because of spurious signals. This is evident by the corrective actions taken in each case. Many of the failures are associated with maintenance and may have been prevented with an improved preventive maintenance program.

Since the majority of failures were not due to faulty measurements and the addition of another channel to monitor critical parameters to provide coincident logic would involve the starting sequence, potentially reducing reliability, the staff finds the proposed trip bypasses acceptable. However, the Millstone Unit 1 IREP study concludes that a significant contributor to core-melt events is a loss-of-normal-ac-power event. Loss of normal ac power accounts for 85% of the total core-melt probability. The major causes of core melt, during loss of normal ac power, identified were the high level of dependence of the high-pressure cooling systems on the gas turbine emergency power source, the generally low reliability of the emergency power system, and the need for the operator to manually depressurize the reactor coolant system, if high-pressure injection failed.

Table 4.2 Gas turbine generator failures at Millstone Unit 1

Report No.	Event date	Event description and problem solution
RS 70-4	11/8/70	Gas turbine generator (GTG) failed to start because of low pressure in the lube oil pump. Startup governing system adjusted.
RS 70-4	12/4/70 (reported)	GTG failed to start because of low pressure in lube oil pump. Two additional immersion heaters installed, set points readjusted.
RS 70-4	1/8/71 (reported)	GTG failed to start within 48 seconds because of installation error of lube oil discharge line. Line reinstalled.
AO 71-5	2/21/71	GTG failed to start after main turbine trip because of blown fuse and faulty relay. Fuse and relay replaced.
AO 71-8	4/22/71	GTG inoperative because of procedural errors. An operator left a switch in the wrong position. Operators instructed as to proper procedure.
AO 71-12	5/27/71	GTG failed to reach startup speed because of a short circuit in speed switch. Switch replaced.
AO 71-24	11/2/71	GTG failed to ignite because of loose solder connections on a transistor speed switch. Transistor replaced.
AO 71-25	11/30/71	Procedural error caused a loss of heating of the lube oil for the GTG. Operators instructed as to proper operation.
AO 72-3	2/4/72	GTG failed to start after plant trip because of wiring errors in vibration monitor package. Errors fixed.
AO 72-11	3/9/72	GTG failed to start after plant trip because of faulty transistor in speed switch. All transistors replaced.
AO 73-5	4/5/73	Operator disabled GTG by turning wrong controller. Cover placed over controller.
AO 75-4	1/29/75	GTG removed from service to replace faulty relay.
AO 75-8	5/20/75	High generator lube oil temperature resulting from incorrect valving caused trip of GTG. Valves locked into current position.

Table 4.2 (Continued)

Report No.	Event date	Event description and problem solution
AO 76-8	2/29/76	GTG did not start because of improper governor setting. Governor readjusted.
AO 76-10	3/8/76	During daily testing of GTG, unit failed to start because of improper governor setting. Governor readjusted.
RO 76-12	3/15/76	GTG declared inoperable because of governor failure. Switches replaced.
AO 76-29	8/10/76	GTG became inoperable when it could not accept plant load on reactor trip. Cause was incorrect ac feed to GTG auxiliaries; ac feed restructured.
AO 76-30	8/31/76	GTG inoperable on overspeed condition because of faulty speed switch. Switch replaced.
LER 77-27	9/9/77	Spurious noise caused GTG to fail to complete startup sequence. No repair reported.
LER 78-12	5/19/78	GTG failed to start because of incorrect fuel scheduling. No repair reported.
LER 78-14	6/13/78	GTG tripped on overspeed because of defective speed switch channel. Speed switch assembly replaced.
LER 78-21	9/14/78	GTG tripped because of faulty speed switch. No repair reported.
LER 78-29	11/22/78	GTG inoperable because of opening of lube oil pump circuit breaker. Breaker indicator bulb replaced.
LER 79-7	2/14/79	GTG failed to start because of faulty speed switch. Switch replaced.
LER 81-20	7/14/81	GTG failed to start because of a stuck shutoff valve for the air start motor. The cause was accumulation of rust in the valve internals. Valve cleaned and reinstalled.
LER 81-28	8/11/81	GTG failed to start because of a generator output breaker failure to close. The cause was oxidation of a potentiometer contacting surfaces. Surfaces were burnished to remove oxide.
LER-81-31	9/10/81	GTG failed to start because of a generator output breaker failure to close. The cause was a wire-wound

Table 4.2 (Continued)

Report No.	Event date	Event description and problem solution
		ceramic resistor that rusted through causing the resistor to fail open. The resistor was replaced.
LER 81-41	12/8/81	GTG became inoperable during operation because of the trip of the output breaker. The cause was oil contaminants in governor. Oil system flushed and fine-mesh screen installed.
LER 82-11	5/8/82	GTG became inoperable while in standby because of the trip of the ac oil pump breaker. The cause was a short in the undervoltage relay for the ac lube oil pump. Relay replaced and fuse added.
LER 82-13	6/15/82	GTG failed to start because of the lack of air supply to the air starter motor. The cause was the failure of the air pressure regulating valve because of rust. Valve replace.
LER 82-17	8/17/82	GTG failed to start because of a lack of air supply to the air start motor. The cause was the failure closed of the air pressure regulating valve because of rust. Air pressure regulating valve cleaned.
LER 82-17	8/24/82	GTG failed to start because of a lack of air supply to the air start motor. The cause was the failure closed of the air pressure regulating valve because of rust. Valve was replaced.

4.28.3 Gas Turbine Preventive Maintenance Program

The limited PRA performed for Millstone Unit 1 concluded that the reduction in core-melt frequency gained by bypassing the protective interlocks is less than 1%. This was determined by subtracting the total failure probability for the protective interlocks (1×10^{-3}) from the failure probability of the gas turbine generator (6×10^{-2}) and requantifying the Millstone Unit 1 IREP. Although bypassing the protective trips was not found to substantially reduce risk, the PRA concluded that the issues of gas turbine generator and diesel generator reliability are important factors in contributing to risk resulting from core melt at Millstone Unit 1. The limited PRA found that failure of the gas turbine generator appears in cut sets that contribute approximately one-quarter of the dominant accident frequency and that the failure rate of the gas turbine generator is relatively high.

Consequently, the staff considers the matter of onsite ac power at Millstone Unit 1 to be an area where a substantial reduction in risk can be attained.

Since many of the gas turbine failures might have been eliminated with an effective preventive maintenance program, the staff concludes that such a program should be developed and implemented, or if such a program already exists, the licensee should review the program for areas where it can be improved or justify why the existing program is adequate.

The staff will require that the licensee perform such an evaluation, identify any necessary corrective actions, submit the results to the staff by April 1983, and coordinate any corrective actions with the recommendations that evolve from the overall evaluation of loss of ac power in Unresolved Safety Issue A-44, "Station Blackout."

4.28.4 Generator Trips

The seven protective trips associated with the output breaker of the gas turbine generator are

(1) loss of exitation
(2) opening of the exciter breaker
(3) generator differential
(4) negative sequence
(5) reverse power
(6) generator underspeed
(7) voltage restrained overcurrent

The licensee has proposed to maintain generator differential and voltage-restrained overcurrent trips and bypass the remainder under accident conditions as is currently done on the diesel generator.

The staff finds this proposal acceptable. The modifications mentioned above will be implemented during the 1984 refueling outage.

4.28.5 Annunciators

The gas turbine generator annunciators should be modified to meet the requirements of IEEE Std. 279-1971, Section 4.20.

With regard to the gas turbine annunciator, the licensee has reviewed the alarm and control circuitry. The results of this evaluation of both the diesel and gas turbine were provided to the staff in a letter dated May 31, 1977. The staff indicated in a letter dated March 31, 1978 that the modifications to the gas turbine proposed by the licensee were acceptable. These modification were installed during the 1980 refueling outage

4.29 Topic VIII-3.A, Station Battery Test Requirements

10 CFR 50 (GDC 18), as implemented by Regulatory Guide 1.129, requires periodic testing for determining battery capacity and for demonstrating that the batteries will provide sufficient power under accident conditions.

The Millstone Unit 1 battery surveillance requirements are included in Section 4.9.B of the station Technical Specifications. The specifications require a battery discharge test at each refueling outage or at least every 18 months. The current licensing requirement for this test is 60 months; however, there is no battery service test required in the station Technical Specifications.

The staff proposes that the testing of the batteries be in accordance with IEEE Std. 450-1975, IEEE Std. 308-1974, BTP EICSB 6, and the "Standard Technical Specifications for General Electric Boiling Water Reactors" (NUREG-0123). The proposed tests are as follows:

(1) At least once every 18 months, during shutdown, a battery service test should be performed to verify that the battery capacity is adequate to supply and maintain in operable status all of the actual emergency loads for 2 hours.

(2) At least once every 60 months, during shutdown, a battery discharge test should be performed to verify that the battery capacity is at least 80% of the manufacturer's rating.

The limited PRA performed for Millstone Unit 1 concludes that the issue of dc power availability may be an important item in risk reduction.

The licensee has agreed to revise the battery testing program to require battery service and discharge tests. The licensee will propose a Technical Specification change by January 3, 1983.

4.30 Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation

10 CFR 50.55a(h), through IEEE Std. 279-1971, and 10 CFR 50 (GDC 2, 4, 5, 17, 18, and 19), as implemented by SRP Section 8.3.2, Regulatory Guides 1.6, 1.32, 1.47, 1.75, 1.118, and 1.129, and BTP ICSB 21, require that the control room operator be given timely indication of the status of the batteries and their availability.

As a minimum, the following indications and alarms of the Class 1E dc power system(s) status shall be provided in the control room:

(1) battery current (ammeter-charge/discharge)
(2) battery charger output current (ammeter)
(3) dc bus voltage (voltmeter)
(4) battery charger output voltage (voltmeter)
(5) battery high discharge rate alarm
(6) dc bus undervoltage and overvoltage alarm
(7) dc bus ground alarm (for ungrounded system)
(8) battery breaker(s) or fuse(s) open alarm
(9) battery charger output breaker(s) or fuse(s) open alarm
(10) battery charger trouble alarm (one alarm for a number of abnormal conditions which are usually indicated locally)

Millstone Unit 1 has two 125-V dc buses (DC-1 and DC-1A) and two 24-V dc systems.

The staff's topic review found that the Millstone Unit 1 control room has no indication of battery current, charger output current, bus voltage (24-V dc systems), charger output voltage, bus undervoltage (24-V dc systems) or overvoltage, bus ground (24-V dc systems), battery breaker/fuse status (24-V dc systems), or charger output breaker/fuse status.

The limited PRA performed to determine the importance to risk of dc instrumentation, indication, and alarms determined that additional monitoring devices would reduce the battery unavailability. In the Millstone Unit 1 IREP analysis, the cut sets, which included dc battery failures, contributed 5.5% to the total risk resulting from core melt.

The limited PRA concluded that improved instrumentation would reduce battery unavailability by 50% and that this would reduce core-melt frequency by 0.6%. The PRA found that the major contributor to dc unavailability is maintenance, because the Technical Specifications allow operation for 128 hours with one battery out of service. If maintenance unavailability is reduced by 50% in addition to improved instrumentation, a reduction of core-melt frequency of 2.5% results. The PRA recommended that allowable outage times for a battery be reviewed.

Because the 24-V system is used only for neutron monitoring, the staff considers the existing 24-V system indications acceptable.

The staff's position for the 125-V system is that at a minimum, battery current and charger output current have local indication and be alarmed in the control room so that the operator will be alerted to the operability of the power system. Also, breaker status should be monitored in the control room or administratively controlled.

During the integrated assessment, it was determined that there are control room indications for battery breaker open and charger output current. It is the staff's position that battery current also be alarmed or instrumentation provided in the control room and that the licensee propose a revision to existing Technical Specifications that reduces current battery outage limits or justify present battery outage limits.

The licensee has not yet formally responded to either issue. During the ACRS Subcommittee meeting, the licensee agreed with the staff's position on additional dc system monitoring in the control room. The issue of allowable outage times for station batteries has recently been identified and the licensee has not had sufficient time to prepare a response.

4.31 Topic IX-3, Station Service and Cooling Water Systems

10 CFR 50 (GDC 44), as implemented by SRP Sections 9.2.1 and 9.2.2, requires a system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink; this system shall have suitable redundancy in components and features and suitable interconnections, leak detection, and isolation capabilities to ensure that for onsite or offsite power system operation the system safety function can be accomplished, assuming a single failure.

During the staff's review the following issue has been identified: A single failure in nonredundant pipe runs of the service water system and the turbine building secondary closed cooling water system could result in loss of system function.

The service water system is susceptible to a single passive failure in the pipe run from the intake structure to essential equipment located in the reactor and turbine buildings. The essential equipment serviced by the service water system is the diesel generator and the turbine building secondary closed cooling water system heat exchangers. The equipment serviced by the turbine building secondary closed cooling water system consists primarily of components of the feedwater coolant injection (FWCI) system. Since loss of this equipment will not inhibit safe shutdown of the plant, the turbine building secondary closed cooling water system can be considered nonessential for the purposes of this review.

A passive failure in the service water line would also result in loss of cooling to the diesel generator; however, the gas turbine generator, which is air cooled, could provide emergency power. Should the gas turbine also be unavailable, the isolation condenser, which is independent of ac power, could be used to maintain the plant in a safe shutdown condition.

The limited PRA of this issue found that failure of the station service and cooling water systems that appeared in the dominant accident sequences had probabilities of approximately 10^{-3} and pipe segment failure had probabilities of about 10^{-9}: thus, the effect on core-melt frequency or risk is negligible. The limited PRA did not consider the issue of the service water lines underlain by peat. These pipes may experience excessive settlement resulting in excessive pipe stresses. Rather, the limited PRA performed was based on historical passive pipe failure rates per unit length of pipe.

For the reasons indicated, backfitting is not recommended pending acceptable results from the review of Topic II-4.F where it was identified that the service water line may be underlain by peat.

4.32 Topic IX-5, Ventilation Systems

10 CFR 50 (GDC 4, 60, and 61), as implemented by SRP Sections 9.4.1, 9.4.2, 9.4.3, 9.4.4, and 9.4.5, requires that the ventilation systems shall have the capability to provide a safe environment for plant personnel and for engineered safety features. The staff's review of the ventilation systems for the Millstone Unit 1 plant found them acceptable except for the following four items.

4.32.1 Core Spray and LPCI Systems Ventilation Systems

The emergency core spray (CS) subsystem and the low-pressure coolant injection (LPCI) subsystem ventilation system are subject to disabling single failures. The LPCI and CS pumps are located in corner rooms on the basement level of the reactor building. Each of the two rooms contains a room cooler (HVH-15 and HVH-16) consisting of a fan and a water-cooled heat exchanger. Water cooling is provided by means of the turbine building secondary cooling water system. The fans are powered by motor control centers MCC 2-3 and MCC 2A-3 from separate essential electrical buses. A single active failure would interrupt space cooling in one of the rooms. Since the CS system uses one 100% pump in each room and the LPCI/containment spray system uses two 33% pumps in each room, the failure of all pumps in a room would remove all backup for the CS system and reduce the LPCI/containment spray system to 66% pumping capacity.

The Millstone IREP considered failure of safety systems resulting from inadequate ventilation and did not identify any systems where ventilation was a concern.

As under Topic VI-7.A.3 (Section 4.21.1), the licensee states that the space coolers are not essential and will provide the staff with information to substantiate this conclusion by November 30, 1982.

4.32.2 Reinitiation of Ventilation Following Loss of Offsite Power

Following a loss-of-offsite-power event, operator action is required to reinitiate the turbine building ventilation system. The licensee should define the maximum period the system could be inoperative and demonstrate that the equipment serviced is unaffected by this lack of ventilation. In addition, the licensee should also demonstrate that the amount of hydrogen generated as a result of battery charging during that period will not exceed the minimum combustion limit.

The licensee will provide this analysis by February 1, 1983.

4.32.3 Lack of Information

Insufficient information on the design and operation of the area space coolers for the FWCI and diesel generator areas precluded the completion of the staff's review of these units.

The licensee will provide the information by February 1, 1983.

4.32.4 Intake Structure Ventilation System

The station cooling water system supplies service water to the diesel generator cooling heat exchangers and the turbine building secondary cooling water heat exchangers and also fills other nonessential needs.

The intake structure ventilation system, which services the station cooling water pumps, does not receive electrical power from emergency sources. Therefore, its operation cannot be ensured after a loss-of-offsite-power event. Although the staff agrees that the buildup of heat in the intake structure would be gradual and could potentially be alleviated by the opening of doors, especially if large overhead truck-entrance doors are available, the licensee should demonstrate that sufficient ventilation by the opening of doors and other infiltration can be provided in a timely manner.

The licensee will provide this analysis by February 1, 1983.

4.33 Topic XV-1, Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

10 CFR 50.34 requires that each applicant for a construction permit or operating license provide an analysis and evaluation of the design and performance of

structures, systems, and components of the facility with the objective of assessing the risk to public health and safety resulting from operation of the facility, including determination of the margins of safety during normal operations and transient conditions anticipated during the life of the facility.

10 CFR 50 (GDC 10 and 15), as implemented by SRP Sections 15.1.1 through 15.1.4, requires that plants be adequately designed to mitigate the consequences of feedwater system malfunctions that result in an increase in feedwater flow.

The staff's review of a feedwater controller failure has determined that the acceptance criteria are met only if the turbine bypass system is operable. Currently, the licensee does not have Technical Specifications that require surveillance of the turbine bypass system or that limit the reactor power or minimum critical power ratio (MCPR) when the turbine bypass system is found to be inoperable. Because the feedwater controller failure with failure of the turbine bypass may be a limiting transient, exceeding the fuel design limits could result. It is also possible that another transient limits MPCR or reactor power and no change is required.

The staff concludes that analysis of feedwater controller failure without bypass should not be required for the current fuel cycle for the following reasons:

(1) At Millstone Unit 1, the turbine control valves and bypass valves are controlled by a common system referred to as the mechanical-hydraulic control (MHC) system. The system components, with the exception of the final valve actuators, are common to both the control and bypass valves. Thus, it is improbable that a failure could occur in the bypass valve portion of the system without affecting the control valve portion of the system. A malfunction in the MHC system that renders the bypass system inoperable would also most likely affect operation of the turbine control valves and would necessitate immediate repair in order to continue operation. The control valve final actuators and the common components of the MHC system are exercised continuously while performing the normal reactor pressure control function. Therefore, continuous operability of the MHC system is ensured.

    During startups, the bypass valves are used, thus providing assurance of their operability.

(2) The limited PRA performed for Millstone Unit 1 concluded that the historical rate of turbine bypass unavailability has been small compared with other causes of loss of the power conversion system so that limitations on reactor operation when the turbine bypass is unavailable would result in a negligible reduction in core-melt frequency.

The plant will shut down in the spring of 1984 for a refueling outage. If credit is taken in the reload analysis for operability of turbine bypass, the staff will require appropriate surveillance of the turbine bypass valves and limits for reactor power or MCPR if the turbine bypass is found inoperable. Technical Specifications should be developed and reviewed as part of the core reload evaluation to reflect the fuel vendor and cycle-specific characteristics of the core.

Backfitting, therefore, is not recommended.

4.34 Topic XV-3, Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)

10 CFR 50 (GDC 10 and 15), as implemented by SRP Section 15.2.1, requires that the plant should be able to respond to a loss of external load in such a way that the criteria regarding fuel damage and system pressure are met.

During the staff's review the following issue has been identified: At Millstone Unit 1, the MCPR was calculated based on an initial power level of 100%. Current criteria require that the initial power level be taken as 100% power plus an allowance of 2% to account for power measurement uncertainties. The higher actual power level could lead to an MCPR that is less than the safety limit.

The licensee has analyzed this transient for Reload 8 using the NRC-approved ODYN code. Although this analysis assumed an initial power level of 100%, an uncertainty factor of 1.044 was used to determine the maximum reduction in the critical power ratio. This 4.4% overall uncertainty factor more than compensates for the difference in initial power level assumed.

The staff concludes that further analysis of this event is not warranted. Backfitting is not recommended.

4.35 Topic XV-16, Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment

10 CFR 100, as implemented by SRP Section 15.6.2, requires that the radiological consequences of failure of small lines carrying primary coolant outside containment be limited to small fractions of the exposure guidelines of 10 CFR 100.

The staff has determined that Millstone Unit 1 does not comply with current licensing criteria. Based on the existing Technical Specification limits for primary coolant activity, the potential offsite doses would substantially exceed the applicable dose limits. It is the staff's position that reactor coolant activity limits should be maintained within the limits imposed on new operating reactors, that is, within the limits of the Standard Technical Specifications (STS) for General Electric Boiling Water Reactors (NUREG-0123). This is necessary to limit plant operation with potentially significant amounts of failed fuel so that the radiological consequences of events that do not damage fuel but do involve a release of reactor coolant to the environment will be low. However, reducing reactor coolant activity to the STS level would not result in calculated doses, using current licensing criteria, that are within the limits specified. This is due to the quantity of primary coolant that would be released at Millstone Unit 1 if an instrument line or other typical small line were to fail. New plant designs use flow-restricting devices or valves capable of being remotely closed. However, for the following reasons, the staff concludes that backfitting flow-restricting devices (orifices or flow-restricting check valves) is not appropriate:

(1) The analysis of radiological consequences used the conservative assumptions specified in the Standard Review Plan (NUREG-0800).

(2) Risk assessments have shown that events that do not involve core melt are not dominant contributors to risk.

(3) The costs associated with hardware modifications are not justified based on the results of risk assessments.

However because of the radiological consequences of this accident in the absence of core melt, it is the staff's position that primary coolant activity be maintained within acceptable limits. It is the staff's position that backfitting the General Electric STS limits for reactor coolant activity is sufficient to ensure that the radiological consequences to the environment from a failure of small lines would be adequately mitigated and establish appropriate limiting conditions for operation in the event of fuel failures.

The license disagrees with this position.

4.36 Topic XV-18, Radiological Consequences of a Main Steam Line Failure Outside Containment

10 CFR 100, as implemented by SRP Section 15.6.4, requires that the radiological consequences of failure of a main steam line outside containment be limited to small fractions of the exposure guidelines of 10 CFR 100. On the basis of an independent assessment of the radiological consequences of a main steam line failure outside containment, the staff has determined that Millstone Unit 1 does not meet the current acceptance criteria for this topic. If the existing Technical Specification limits for primary coolant activity are used, the potential offsite doses would substantially exceed the applicable dose limits.

The limited PRA for Millstone Unit 1 concluded that this issue does not affect any core-melt sequence and thus has no effect on core-melt frequency or risk. This is because PRAs calculate risk from core-melt accidents that dominate the risk. However, because of the radiological consequences of this accident in the absence of core melt, it is the staff's position that primary coolant activity be maintained with acceptable limits. It is the staff's position that the licensee should maintain the primary coolant activity within the General Electric STS limits, which would meet the acceptance criteria. Since the staff's analysis shows that the small-line failure is more limiting than the main steam line failure, resolution of Topic XV-16 will also resolve the concerns of Topic XV-18.

The licensee disagrees with this position.

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APPENDIX A

TOPIC DEFINITIONS FOR SEP REVIEW*

*The topic definitions and other data appearing in this appendix were assembled in April 1977; therefore, some references to organizations and other references reflect the status of the review at that time. The basis for deletion of a topic because the review of the related TMI task, USI, or other SEP topic was identical to the review of the SEP topic was developed in May 1981 on a generic basis and does not address the plant-specific design aspects. The plant-specific deletions resulting from generic reviews or nonapplicability to the Millstone Unit 1 design are given in Appendices B and C.

CONTENTS

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

CONTENTS (Continued)

TOPIC: II-1.A Exclusion Area Authority and Control

(1) Definition:

The establishment of the exclusion area and the licensee's control over it are reviewed at the construction permit/operating license stage. Thereafter, the licensees are required to report any changes with safety implications. The concern exists, however, that (1) the original review may not have been as thorough as currently done, or (2) changes may have occurred but have not been reported and reviewed. In particular, new activities within the exclusion area (for example, new recreational facilities or offshore oil drilling) and topographical changes (for example, changes in water levels) may need to be reviewed.

(2) Safety Objective:

To assure that appropriate exclusion area authority and control is maintained by the licensee.

(3) Status:

Selective reviews have been performed (San Onofre Nuclear Generating Station Unit 1) or are under way (Fort Calhoun) where changes in exclusion area boundary have become necessary.

(4) References:

1. Title 10, "Energy," Code of Federal Regulations, Part 100*
2. NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants - LWR Edition, "December 1975,"** Section 2.1.2

TOPIC: II-1.B Population Distribution

(1) Definition:

Population distribution in the vicinity of operating plants may have changed since the initial review was performed at the construction permit stage. Special attention should be given to new housing and commercial, military, or institutional installations established since the initial population-distribution review.

(2) Safety Objective:

New population distributions may require revision of low-population zone (LPZ) and population center to assure appropriate protection for the public by complying with the guidelines of 10 CFR Part 100. Adjustments may have

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*Hereafter referred to as 10 CFR.

**Hereafter referred to as Standard Review Plan.

to be made in emergency plans. New accident analyses may have to be performed to determine consequent conformance with 10 CFR Part 100 at new LPZ distances. Potential need for additional engineered safety features (for example, chemical sprays or better filters) exists.

(3) Status:

Has been done on a selective basis only, that is, Pilgrim Unit 1 new population center.

(4) References:

1. 10 CFR Part 100
2. Standard Review Plan, Section 2.1.3

TOPIC: II-1.C Potential Hazards or Changes in Potential Hazards Due to Transportation, Institutional, Industrial, and Military Facilities

(1) Definition:

For operating plants there are three concerns:

(a) New hazards created since the facility was licensed,

(b) Hazards considered for licensing but that have expanded beyond projections or which were not reviewed against current criteria, and

(c) Hazards that were not analyzed at the licensing stage because of lack of regulatory criteria at the time.

Nearby transportation, institutional, industrial, and military facilities may be threats to safe plant operation due to:

(a) Control room infiltration of toxic gases,

(b) Onsite fires triggered by transport of combustible chemicals from offsite releases,

(c) Shock waves due to detonation of stored or transported explosives and military ordnance firing, and

(d) Onsite aircraft impact.

(2) Safety Objective:

To assure that the control room is habitable at all times and that the postulated hazards will not result in releases in excess of the 10 CFR Part 100 guidelines by disabling systems required for safe plant shutdown.

(3) Status:

Action has been taken on a selective basis only, for example, curbing of military air activity in the vicinity of the Big Rock Point Plant. Liquid natural gas (LNG) hazards at Calvert Cliffs are under review. The review of older plants did not consider offsite hazards in detail (for example, aircraft traffic in the vicinity).

(4) Reference:

Standard Review Plan, Sections 2.2.1 and 2.2.2

TOPIC: II-2.A Severe Weather Phenomena

(1) Definition:

Safety-related structures, systems, and components should be designed to function under all severe weather conditions to which they may be exposed. Meteorological phenomena to be considered include tornadoes, snow and ice loads, extreme maximum and minimum temperatures, lightning, combinations of meteorology and air-quality conditions contributing to high corrosion rates, and effects of sand and dust storms.

(2) Safety Objective:

To assure that the designs of safety-related structures, systems, and components reflect consideration of appropriate extreme meteorological conditions and severe weather phenomena. This effort would identify deficiencies in designs and/or operation that may contribute to accidental releases of radioactivity to the atmosphere resulting in doses to the public in excess of 10 CFR Part 100 or Part 20 guidelines (as appropriate to the design of the component or system).

(3) Status:

Generic studies have been initiated to develop guidelines for extreme temperatures and lightning, and to the review the current Branch Positions on snow loads. Estimated completion dates are 6/1/78 or later.

(4) References:

1. 10 CFR Part 100 or Part 20
2. Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants"
3. Standard Review Plan, Section 2.3.1
4. Branch Technical Position, "Winter Precipitation Loads," March 24, 1975
5. Inquiry by Chairman Rowden Concerning Lightning Protection, July 9, 1976
6. 10 CFR Part 50

TOPIC: II-2.B Onsite Meteorological Measurements Program

(1) Definition:

To review the onsite meteorological measurements program to determine the extent that the licensee complies with 10 CFR Part 50, Appendix E and Appendix I.

(2) Safety Objective:

To assure that adequate meteorological instrumentation to quantify the offsite exposures from routine releases is available and maintained.

(3) Status:

Onsite meteorological measurements programs are being reviewed as a part of the Appendix I evaluations.

(4) References:

1. 10 CFR Part 50, Appendix E and Appendix I
2. Regulatory Guide 1.97, Rev. 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident"
3. Regulatory Guide 1.23, "Onsite Meteorological Programs"
4. Standard Review Plan, Section 2.3.3

(5) Basis for Deletion (Related TMI Task, Unresolved Safety Issue (USI), or Other SEP Topic):

(a) TMI Action Plan Task II.F.3, "Instrumentation for Monitoring Accident Conditions" (NUREG-0660)

Task II.F.3 requires that appropriate instrumentation be provided for accident monitoring with expanded ranges and a source term that considers a damaged core capable of surviving the accident environment in which it is located for the length of time its function is required. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," issued December 1980, contains the required meteorological instrumentation to quantify the offsite exposure.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term" (NUREG-0660)

Task III.A.1 requires the evaluation of 10 CFR Part 50, Appendix E, backfit requirements in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." Backfit requirements include review of the Onsite Meteorological Measurement Program.

The evaluations required by Tasks II.F.3 and III.A.1 are identical to SEP Topic II-2.B; therefore, this SEP topic has been deleted.

TOPIC: II-2.C Atmospheric Transport and Diffusion Characteristics for Accident Analysis

(1) Definition:

To review the atmospheric transport and diffusion characteristics assumed to demonstrate compliance with the 10 CFR 100 guidelines with respect to plant design, control room habitability, and doses to the public during and following a postulated design-basis accident. This effort would examine the assumptions for:

(a) Effects of explosive concentrations from onsite or offsite releases of hazardous material for consideration in structural design,

(b) Calculation of relative concentration (x/Q) values for releases of radioactivity and toxic chemicals for consideration in control room habitability, and

(c) Calculations of doses to the public resulting from releases of radioactivity to the atmosphere during and following a postulated design-basis accident.

This effort is considered necessary because most original reviews were performed using the assumptions provided in Regulatory Guides 1.3 and 1.4 which have been found to be generally nonconservative based on evaluation of over 50 sites with actual meteorological observations.

(2) Safety Objective:

To assure that the atmospheric transport and diffusion characteristics originally assumed to demonstrate compliance with the 10 CFR 100 guidelines are appropriate, considering additional onsite meteorological data and results of recent atmospheric diffusion experiments.

(3) Status:

A review of long-term (annual average) atmospheric transport and diffusion characteristics is ongoing for Appendix I evaluations independent of the SEP effort. A study has also recently been performed by the Hydrology-Meteorology Branch for the Division of Operating Reactors for review of the meteorological assumptions for estimating control room dose consequences resulting from post-LOCA purges through tall stacks.

(4) References:

1. 10 CFR Part 20
2. 10 CFR Part 50, Appendix A and Appendix I
3. 10 CFR Part 100
4. Regulatory Guides
   1.3, "Assumption Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Boiling Water Reactors"
   1.4, "Assumptions Used for Evaluating the Potential Radiologcal Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors"
5. Standard Review Plan, Sections 2.3.4, 6.4, 2.2.1, 2.2.2, and 2.2.3

TOPIC: II-2.D Availability of Meteorological Data in the Control Room

(1) Definition:

Data from the onsite meteorological program should be available in the control room.

(2) Safety Objective:

To assure that the lincensee has appropriate meteorological logical data displayed in the control room to assess conditions during and following an accident to allow for (1) early indication of the need to initiate action necessary to protect portions of the offsite public and (2) an estimate of the magnitude of the hazard from potential or actual accidental releases.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 50, Appendix E and Appendix I
2. Regulatory Guide 1.97, Rev. 1, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident"
3. Regulatory Guide 1.23, "Onsite Meteorological Programs"
4. Standard Review Plan, Section 2.3.3

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) TMI Action Plan Task II.F.3, "Instrumentation for Monitoring Accident Conditions" (NUREG-0660)

Task II.F.3 requires that appropriate instrumentation be provided for accident monitoring with expanded ranges and a source term that considers a damaged core capable of surviving the accident environment in which it is located for the length of time its function is required. Regulatory Guide 1.97, Revision 2, "Instrumentation for Light-Water-Cooled Nuclear Power Plants To Assess Plant and Environs Conditions During and Following an Accident," issued December 1980, contains the required meteorological instrumentation to quantify the offsite exposure.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term" (NUREG-0660)

Task III.A.1, "Improve Licensee Emergency Preparedness - Short Term," requires the evaluation of 10 CFR Part 50, Appendix E backfit requirements in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." Backfit requirements include review of the Onsite Meteorological Measurement Program.

(c) TMI Action Plan Task I.D.1, "Control Room Design Reviews" (NUREG-0660)

Task I.D.1, "Control Room Design Reviews," requires that operating reactor licensees and applicants for operating licenses perform a detailed control room design review to identify and correct design deficiencies. This review will include an assessment of control room layout, the adequacy of the information provided, the arrangement and identification of important controls and instrumentation displays, the usefulness of the audio and visual alarm systems, the information recording and recall capability, lighting, and other considerations of human factors that have an impact on operator effectiveness.

The evaluations required by Tasks II.F.3, III.A.1, and I.D.1 are indentical to SEP Topic II-2.D; therefore, this SEP topic has been deleted.

TOPIC: II-3.A Hydrologic Description

(1) Definition:

Hydrologic considerations are the interface of the plant with the hydrosphere, the identification of hydrologic causal mechanisms that may require special plant design or operating limitations with regard to floods and water supply requirements, and the identification of surface- and groundwater uses that may be affected by plant operation.

These hydrologic considerations may have changed since they were reviewed at the licensing stage. A review of such changes, if any, should be performed including an assessment of their impact on the plants.

(2) Safety Objective:

To assure that the designs of safety-related structures, systems, and components reflect consideration of appropriate hydrologic conditions, and to identify deficiencies in designs and/or operations that could contribute to accidental radioactive releases.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Parts 20, 50, and 100
2. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
3. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
4. Standard Review Plan, Section 2.4.1

TOPIC: II-3.B Flooding Potential and Protection Requirements

(1) Definition:

If the potential for floods exists and protection is required, the type of protection (sand bags, flood doors, bulkheads, and so forth) will be reviewed to assure that equipment is available and that provisions have been made to implement the required protection.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against floods.

(3) Status:

Flooding protection requirements were reviewed on selected operating plants during the winter of 1976 due to the potential for flooding caused by ice accumulation and predictions for abnormally high spring runoff for some areas.

(4) References:

1. 10 CFR Parts 50 and 100
2. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
3. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
4. Standard Review Plan, Section 2.4.10

TOPIC: II-3.B.1 Capability of Operating Plants To Cope With Design-Basis Flooding Conditions

(1) Definition:

Protection against postulated floods is accomplished, if necessary, by "hardening" the plant and by implementing appropriate technical specifications and emergency procedures.

These technical specifications and flood emergency procedures need to be reviewed for plants licensed prior to 1972 to establish the degree of conformance with current criteria. Flooding criteria used for the design of older plants are not known.

(2) Safety Objective:

Same as II-3.B

(3) Status:

Same as II-3.B

(4) References:

1. 10 CFR Part 100
2. American National Standards Institute, ANSI N170-1976, "Standards for Determining Design Basis Flooding at Power Reactor Sites"
3. Regulatory Guide 1.59, "Design Basis Floods for Nuclear Power Plants"
4. Standard Review Plan, Sections 2.4.3, 2.4.4, 2.4.5, and 2.4.7

TOPIC: II-3.C Safety-Related Water Supply (Ultimate Heat Sink [UHS])

(1) Definition:

To determine the adequacy of onsite water sources with respect to providing safety-related water during emergency shutdown and maintenance of safe shutdown. The location and inventory of safety-related water sources and the meteorological conditions to be used in evaluating both temperature and inventory of the sources should be established. Considerations of ice, low water, leak potential, and underwater dams should be included. In most cases, plants operating prior to 1973 will have to be reviewed to establish the degree of conformance with current criteria. Prior to the issuance of Regulatory Guide 1.27 in 1973, the Standard Format and Content (now Regulatory Guide 1.70) provided the only guidelines to prospective applicants on UHS requirements. Since compliance was not required and hydrologic and meteorologic criteria had not been established, usually only minimal data were provided.

(2) Safety Objective:

To assure an appropriate supply of cooling water during normal and emergency shutdown procedures.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 100
2. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants"
3. Standard Review Plan, Sections 2.4.11 and 9.2.5

TOPIC: II-4 Geology and Seismology

(1) Definition:

Prior to the adoption of Appendix A to 10 CFR Part 100 in 1973, the Standard Format provided the only guidelines to prospective applicants regarding the type of geologic and seismic information needed by the Atomic Energy Commission staff. The applicant, because compliance with Regulatory Guide 1.70 was not required, usually provided only minimal data. Therefore, a re-review of plants licensed prior to 1973 is needed in order to determine the adequacy of the plant design with respect to geologic and seismologic phenomena such as earthquakes, landslides, ground collapse, and liquefaction.

The review will also include ground motion and surface faulting and will establish the ground-motion values and foundation conditions to be input into the structural reevaluation for seismic loads. (It is possible that some of the older plants would require assessing only the effects of new geologic and seismic discoveries on the site safety and the resulting design acceleration and/or the response spectra.)

(2) Safety Objective:

To assure that accidents (for example, loss-of-coolant accident) do not occur and that plants can safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

Selected plants are undergoing reevaluation of geology and seismology (San Onofre Nuclear Generating Station Unit 1 and Humboldt Bay). A plan for reevaluating operating plants was developed in 1975-76 but has not been implemented pending formation of the Systematic Evaluation Program.

(4) References:

1. Standard Review Plan, Sections 2.5.1, 2.5.2, 2.5.3, 2.5.4, and 2.5.5
2. 10 CFR Part 100, Appendix A

TOPIC: II-4.A Tectonic Province

(1) Definition:

This subtopic covers a specific area within the major topic Geology and Seismology. Its purpose is to reassess the tectonic province for operating plants based on more current knowledge. (A tectonic province is a region characterized by a relative consistency of the geologic structural features contained within. Tectonic provinces are used operationally as regions within which risk from earthquakes not associated with tectonic structures or faults is considered uniform. Usually the largest historical earthquake not associated with a specific structure can be assumed to occur anywhere within the same province.)

(2) Safety Objective:

To assure that plants can be safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

The Geosciences Branch is currently attempting to delineate the boundaries of specific tectonic provinces (estimated completion date, fall 1977). The Site Safety Standards Branch is attempting to revise Appendix A to 10 CFR Part 100 so that the definition of tectonic province will more closely conform to its operational use (estimated completion date, 1978). We currently accept such provinces as generally proposed by King, Rogers, or Eardley. Limited subdivision of these provinces has been allowed based on thorough geological and seismic analyses.

(4) References:

1. 10 CFR Part 100, Appendix A
2. King, P. B., Tectonic Map of North America; Washington, D.C., U.S. Geological Survey, 1969
3. Rogers, John, The Tectonics of the Appalachians, N.Y., Wiley-Interscience, 271 p, 1970
4. Eardley, A. H., "Tectonic Divisions of North America," Bulletin of the American Association of Petroleum Geologists, 35: 2229-2237, 1951

TOPIC: II-4.B Proximity of Capable Tectonic Structures in Plant Vicinity

(1) Definition:

This subtopic covers a specific area within the major topic Geology and Seismology. Its purpose is to determine the expected shaking characteristics at a plant site from known capable faults. The ground motion associated with an earthquake generated by a capable fault or a tectonic structure may be greater than that associated with earthquakes in the same tectonic province not related to the structure.

(2) Safety Objectives:

To assure that plants can be safely shut down in the event of geologic and seismologic phenomena which may occur at the site.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. 10 CFR Part 100, Appendix A
2. Standard Review Plan, Section 2.5.2
3. Regulatory Guide 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"

TOPIC: II-4.C Historical Seismicity Within 200 Miles of Plant

(1) Definition:

Determination of the safe shutdown earthquake (SSE) is made with consideration of past seismicity in the vicinity of the plant. However, there is sometimes disagreement or inconsistency in reporting older earthquakes in the literature. Current high seismicity may also indicate possible hidden tectonic features.

The historical seismicity within 200 miles of the plants will be reviewed including all earthquakes of Richter magnitude greater than 3.0 or of Modified Mercalli intensity greater than III. Association with tectonic features and provinces should be included.

(2) Safety Objective:

To assure that the SSE is compatible with past seismicity in the area.

(3) Status:

No work currently being done in this subject for operating reactors.

(4) References:

1. Richter, C. F., Elementary Seismology, W. H. Freeman and Company, San Francisco, Calif., 1958
2. 10 CFR Part 100, Appendix A

TOPIC: II-4.D Stability of Slopes

(1) Definition:

Overstressing a slope may cause sudden failure with rapid displacement or shear strain which may damage safety-related structures. The possibility of movement is evaluated by comparing forces resisting failure to those causing failure. An assessment of this ratio should be made to determine the safety factor.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against failure of natural or man-made slopes.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Section 2.5.5
2. 10 CFR Part 100, Appendix A
3. Naval Facilities Engineering Command, NAVFAC DM-7, "Design Manual - Soil Mechanics, Foundations, and Earth Structures."

TOPIC: II-4.E Dam Integrity

(1) Definition:

Dam integrity is the ability of a dam to safely perform its intended functions. These functions would normally include remaining stable under all conditions of reservoir operation, controlling seepage to prevent excessive uplifting water pressures or erosion of soil materials, and providing sufficient freeboard and outlet capacity to prevent overtopping.

(2) Safety Objective:

To assure that adequate margins of safety are available under all loading conditions and uncontrolled releases of retained liquid are prevented.

For many projects an important consideration is the necessity of assuring that an adequate quantity of water is available in times of emergency.

(3) Status:

Additional guidance on assuring the integrity of dams is currently being developed by the Office of Standards Development in Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants," and through the geotechnical engineering service contract with the U.S. Army Corps of Engineers on design of structures such as ultimate heat sinks.

(4) References:

1. Standard Review Plan, Section 2.5.6
2. 10 CFR Part 100, Appendix A
3. U.S. Army Corps of Engineers, EM 1110-2-1902, "Engineering and Design Stability of Earth and Rock-Fill Dams," Office of Chief of Engineers, 1970
4. U. S. Army Corps of Engineers, EM 1110-2-2300, "Earth and Rock-Filled Dams General Design and Construction Considerations," 1971
5. Regulatory Guide 3.11, "Design, Construction, and Inspection of Embankment Retention Systems for Uranium Mills"

TOPIC: II-4.F Settlement of Foundations and Buried Equipment

(1) Definitions:

Structural loads develop pressures in compressible strata which are not equivalent to the original geostatic pressures. Settlement and differential settlement should be evaluated.

(2) Safety Objective:

To assure that safety-related structures, systems, and components are adequately protected against excessive settlement.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Section 2.5.4
2. 10 CFR Part 100, Appendix A
3. Naval Facilities Engineering Command, NAVFAC DM-7, "Design Manual - Soil Mechanics, Foundations, and Earth Structures"

TOPIC: III-1 Classification of Structures, Components, and Systems (Seismic and Quality)

(1) Definition:

Plant structures, systems, and components that are required to withstand the effects of a safe shutdown earthquake and remain functional should be classified as Seismic Category I. Systems and components important to safety should be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Review the classification of structures, systems, and components important to safety to assure they are of the quality level commensurate with their safety function.

(2) Safety Objective:

To assure that structures, systems, and components will fullfill their intended safety functions in accordance with design requirements. To assure that structures, systems, and components necessary for safety will withstand the effects of the designated safe shutdown earthquake and will remain functional.

(3) Status:

There is currently no Division of Operating Reactors activity to confirm the classification of structures, components, and systems important to safety of operating reactors.

(4) References:

1. Standard Review Plan, Section 3.2.1
2. Standard Review Plan, Section 3.2.2
3. Regulatory Guide 1.26, "Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants"
4. Regulatory Guide 1.29, "Seismic Design Classification"

TOPIC: III-2 Wind and Tornado Loadings

(1) Definition:

Review the capability of the plant structures, systems, and components to withstand design wind loadings in accordance with 10 CFR 50, Appendix A. The review includes the following: (A) Design Wind Protection; (B) Tornado Wind and Pressure Drop Protection; (C) Effect of Failure of Structures Not Designed for Tornado on Safety of Category I Structures, Systems and Components; (D) Tornado Effects on Emergency Cooling Ponds.

(2) Safety Objective:

To assure that Category I structures, systems, and components are adequately designed for tornado winds and pressure drop, that any damage to structures not designed for tornado-generated forces will not endanger Category I structures, systems, and components, and that tornado winds will not prevent the water in the cooling ponds from acting as a heat sink.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 2
2. Standard Review Plan, Sections 3.3, 3.8, and 9.2.5
3. Regulatory Guides
   1.76, "Design Basis Tornado for Nuclear Power Plants"
   1.117, "Protection of Nuclear Plants Against Industrial Sabotage"

TOPIC: III-3.A Effects of High Water Level on Structures

(1) Definition:

If the high water level for the plant is reevaluated and found to be above the original design basis, then review the ability of the plant structures to withstand this water level.

(2) Safety Objective:

To provide assurance that floods or high water level will not jeopardize the structural integrity of the plant seismic Category I structures and that seismic Category I systems and components located within these structures will be adequately protected.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2
2. Standard Review Plan, Sections 2.4, 3.4, and 3.8
3. Regulatory Guides
   1.59, "Design Basis Floods for Nuclear Power Plants"
   1.102, "Flood Protection for Nuclear Power Plants"

TOPIC: III-3.B Structural and Other Consequences (e.g., Flooding of Safety-Related Equipment in Basements) of Failure of Underdrain Systems

(1) Definition:

Some plants rely on underdrain systems to limit the water table elevation at the plant to a safe level. Review underdrain systems of those facilities in which they are used.

(2) Safety Objective:

To assure that the integrity of underdrain systems is maintained because a failure could lead to a rise in water table elevation which, in turn, could jeopardize the integrity of structures or the safety equipment within such structures.

(3) Status:

The structural consequences of the failure of underdrain systems were thoroughly reviewed during the construction-permit review of Douglas Point Units 1 and 2 and Perry Units 1 and 2. There are no ongoing reviews of this topic for operating facilities.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2
2. Standard Review Plan, Sections 2.4.13, 3.4, and 3.8

TOPIC: III-3.C Inservice Inspection of Water Control Structures

(1) Definition:

Review the adequacy of the inservice inspection program of water control structures for operating plants to assure conformance with the intent of Regulatory Guide 1.127.

(2) Safety Objective:

To assure that water control structures of a nuclear power facility (for example, dams, reservoirs, and conveyance facilities) are adequately inspected and maintained so as to preclude their deterioration or failure which could result in flooding or in jeopardizing the integrity of the ultimate heat sink for the facility.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) Reference:

Regulatory Guide 1.127, "Inspection of Water-Control Structures Associated With Nuclear Power Plants"

TOPIC: III-4.A Tornado Missiles

(1) Definition:

Plants designed after 1972 have been consistently reviewed for adequate protection against tornadoes. The concern exists, however, that plants reviewed prior to 1972 may not be adequately protected, in particular, those reviewed before 1968 when Atomic Energy Commission criteria on tornado protection were developed.

An assessment of the adequacy of a plant to withstand the impact of tornado missiles would include:

(a) Determination of the capability of the exposed systems, components, and structures to withstand key missiles (including small missiles with penetrating characteristics and larger missiles which result in an overall structural impact),

(b) Determination of whether any areas of the plant require additional protection.

The systems, structures, and components required to be protected because of their importance to safety are identified in Regulatory Guide 1.117.

(2) Safety Objective:

To assure that those structures, systems, and components necessary to ensure:

(a) The integrity of the reactor coolant pressure boundary,

(b) The capability to shut down the reactor and maintain it in a safe shutdown condition, and

(c) The capability to prevent accidents which could result in unacceptable offsite exposures,

can withstand the impact of an appropriate postulated spectrum of tornado-generated missiles.

(3) Status:

The Regulatory Requirements Review Committee (RRRC) has approved case-by-case rereviews of plants against criteria in Regulatory Guide 1.117, which establishes the systems, structures, and components required to be protected against tornado missiles. This rereview was deferred pending the formation of the SEP.

The RRRC is in the process of rereviewing Standard Review Plan, Section 3.5.1.4, which establishes appropriate missiles and impact velocities for new applications.

Electric Power Research Institute (EPRI) has missile research in progress.

(4) References:

1. Standard Review Plan, Section 3.5.1.4
2. Regulatory Guide 1.117, "Tornado Design Classification"

TOPIC: III-4.B Turbine Missiles

(1) Definition:

A number of nonnuclear plants and one nuclear plant (Shippingport) have experienced turbine disk failures. Rancho Seco has had chemistry problems leading to sodium deposits which caused stress-corrosion cracking of disks. Failure of turbine disks and rotors can result in high energy missiles which have the potential for resulting in plant releases in excess of 10 CFR 100 exposure guidelines.

Two areas of concern should be considered:

(a) Design overspeed failures - material quality of disk and rotor, inservice inspection for flaws, chemistry conditions leading to stress-corrosion cracking, and

(b) Destructive overspeed failures - reliability of electrical overspeed protection system, reliability and testing program for stop and control valves, inservice inspection of valves.

The focus of the review would be on turbine disk integrity and overspeed protection, including stop, intercept, and control valve reliability.

(2) Safety Objective:

To assure that all the structures, systems, and components important to safety (identified in Regulatory Guide 1.117) have adequate protection against potential turbine missiles either by structural barriers or a high degree of assurance that failures at design (120%) or destructive (180%) overspeed will not occur.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute (EPRI) has missile research in progress.

(4) References:

1. Regulatory Guides
   1.115, "Protection Against Low Trajectory Turbine Missiles"
   1.117, "Tornado Design Classification"
2. Standard Review Plan, Section 3.5.1.3

TOPIC: III-4.C Internally Generated Missiles

(1) Definition:

Review the probability of missile generation and the extent to which safety-related structures, systems, and components are protected against the effects of potential internally generated missiles (including missiles generated inside or outside the containment).

(2) Safety Objective:

To provide assurance that the integrity of the safety-related structures, systems, and components will not be impaired and that they may be relied on to perform their safety functions following any postulated internally generated missile.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute (EPRI) has missile research in progress.

(4) Reference:

Standard Review Plan, Sections 3.5.1.1 and 3.5.1.2

TOPIC: III-4.D Site-Proximity Missiles (Including Aircraft)

(1) Definition:

Review the extent to which safety-related structures, systems, and components are protected against the effects of missiles postulated in Topic II-1.C, including postulated aircraft crashes and resulting fires.

(2) Safety Objective:

To provide assurance that the integrity of the safety-related structures, systems, and components will not be impaired and that they will perform their safety functions in the event of a site-proximity missile.

(3) Status:

No work currently being done on this subject for operating plants. Electric Power Research Institute has missile research in progress.

(4) Reference:

Standard Review Plan, Sections 3.5.1.5, 3.5.1.6, 3.5.2, and 3.5.3

TOPIC: III-5.A Effects of Pipe Break on Structures, Systems, and Components Inside Containment

(1) Definition:

Review the licensee's break and crack location criteria and methods of analysis for evaluating postulated breaks and cracks in high and moderate energy fluid system piping inside containment. The review includes consideration of compartment pressurization, pipe whip, jet impingement, environmental effects, and flooding. Regulatory Guide 1.46 does not require that cracks be postulated inside containment. However, the recent proposed revision to Standard Review Plan, Section 3.6.2, "Determination of Break Locations and Dynamic Effects Associated With the Postulated Rupture of Piping," recommends that cracks be postulated inside containment. Old and current plants are not postulating cracks.

(2) Safety Objective:

To assure that the integrity of structures, systems, and components relied upon for safe reactor shutdown or to mitigate the consequences of a postulated pipe break is maintained.

(3) Status:

This program has not been started for facilities licensed prior to about early 1974. Subsequent to that date, this topic was included in the operating-license review and has been completed for later facilities.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 4
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. Standard Review Plan, Sections 3.6.2 and 3.8
4. Regulatory Guides
   1.46, "Protection Against Pipe Whip Inside Containment"
   1.29, "Seismic Design Classification"

TOPIC: III-5.B Pipe Break Outside Containment

(1) Definition:

Review the licensee's break and crack location criteria and methods of analysis for evaluating postulated breaks and cracks in high and moderate energy fluid system piping located outside containment. The review includes consideration of compartment pressurization, pipe whip, jet impingement, environmental effects, and flooding.

(2) Safety Objective:

To assure that pipe breaks would not cause the loss of needed functions of safety-related systems, structures, and components and to assure that the plant can be safely shut down in the event of such breaks.

(3) Status:

This task is complete for all operating plants with the exception of three plants for which the review is in progress.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 4
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. Standard Review Plan, Section 3.6.1
4. Regulatory Guides
   1.46, "Protection Against Pipe Whip Inside Containment"
   1.29, "Seismic Design Classification"
5. Standard Review Plan, Branch Technical Position MEB 3-1, "Postulated Break and Leakage Locations in Fluid System Piping Outside Containment"
6. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) Issue 3-25
7. Standard Review Plan, Section 3.6.2

TOPIC: III-6 Seismic Design Considerations

(1) Definition:

Review and evaluate the original plant design criteria in the following areas: Seismic Input, Analysis and Design Criteria, Qualification of Electrical and Mechanical Equipment, Seismic Instrumentation, Seismic

Categorization, and the effect of failure of non-Category I structures on the safety of Category I structures, systems, and components.

(2) Safety Objective:

To ensure the capability of the plant to withstand the effect of earthquakes.

(3) Status:

Humboldt Bay and San Onofre plants are currently undergoing seismic review. Technical Assistance Contracts:

(a) Seismic Conservatism (Lawrence Livermore Laboratory)
(b) Elasto-Plastic Seismic Analysis (Lawrence Livermore Laboratory)
(c) Seismic Review of Operating Plants (Newmark)

(4) References:

1. Standard Review Plan, Sections 2.5, 3.7, 3.8, 3.9, and 3.10
2. Regulatory Guides
   1.12, "Instrumentation for Earthquakes"
   1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants"
   1.61, "Damping Values for Seismic Design of Nuclear Power Plants"
   1.92, "Combining Modal Responses and Spatial Components in Seismic Response Analysis"
   1.122, "Development of Flood Design Spectra for Seismic Design of Floor-Supported Equipment or Components"

TOPIC: III-7.A Inservice Inspection, Including Prestressed Concrete Containments With Either Grouted or Ungrouted Tendons

(1) Definition:

Review licensee's inspection program for all Category I structures including steel, reinforced concrete, and prestressed concrete containments. The program should include investigations for possible corrosion and cracking of steel containments, excessive cracking of concrete structures, lift-off tests of tendons, periodic testing of prestressing tendons for containments with grouted tendons, and possible deterioration of prestressed containments.

(2) Safety Objective:

To assure that the licensee's inspection program will detect any damaging deterioration of the structures and that they will be capable of performing as required by 10 CFR 50, Appendix A.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A
2. Standard Review Plan, Section 3.8
3. Regulatory Guides
   1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Structures"
   1.90, "Inservice Inspection of Prestressed Concrete Containment Structures With Grouted Tendons"

TOPIC: III-7.B Design Codes, Design Criteria, Load Combinations, and Reactor Cavity Design Criteria

(1) Definition:

Review the design codes, design criteria, and load combinations for all Category I structures (that is, containment, structures inside containment, and structures outside containment).

(2) Safety Objective:

To provide assurance that the plant Category I structures will withstand the NRC specific design conditions without impairment or structural integrity or the performance of required safety functions.

(3) Status:

This review applies to all plants. There are no ongoing reviews concerning this matter.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 2 and 4
2. Standard Review Plan, Section 3.8

TOPIC: III-7.C Delamination of Prestressed Concrete Containment Structures

(1) Definition:

Review the design of prestressed concrete containment structures to assess the likelihood of delamination occurring in the shell walls or dome and to evaluate the consequences, if any.

(2) Safety Objective:

To assure that the licensee's design and construction methods have provided a structure which will maintain its integrity and will perform its intended function. Delaminations (internal cracking of concrete in planes roughly parallel to the surface) could possibly reduce the capability of the concrete to withstand compression.

(3) Status:

This review applies to all plants with prestressed concrete containments. A delamination occurred in the domes of the Turkey Point and Crystal River prestressed concrete containments. No evidence of such occurrences have been reported at other plants; however, no specific inspections have been made for any delaminations. It is not clear if the Structural Integrity Test or the existing inservice inspection programs would discover the existence of any delaminations.

(4) References:

Safety Evaluation Reports for Turkey Point (Docket No. 50-250/251) and Crystal River (Docket No. 50-302)

TOPIC: III-7.D Containment Structural Integrity Tests

(1) Definition:

Review the licensee's structural integrity testing procedure to ensure compliance with the requirements of 10 CFR 50, Appendix A.

(2) Safety Objective:

To assure that the licensee's design and constructive methods provide a structure which will safely perform its intended functions.

(3) Status:

This review applies to all plants. To our knowledge, all containments have had a structural integrity test. This opinion should be verified.

(4) References:

1. 10 CFR Part 50, Appendix A
2. Standard Review Plan, Sections 3.8.1 and 3.8.2

TOPIC: III-8.A Loose-Parts Monitoring and Core Barrel Vibration Monitoring

(1) Definition:

Inservice surveillance programs to detect loose parts and excessive motion of the main core support structure.

(2) Safety Objective:

To detect loose parts or excessive vibration before they can cause flow blockage or mechanical damage to the fuel or other safety-related components.

(3) Status:

The NRC staff currently requires applicants to describe and licensees to implement a loose-part detection program. Guidance for such a program is provided in a newly proposed Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors." The regulatory guide outlines the minimum system characteristics which the NRC staff feels are necessary for a workable system and combines this with a technical specification and reporting procedures for a complete and enforceable loose-part detection program.

The concept of detecting core barrel motion through use of excore neutron detectors is well established. A proposed regulatory guide that describes an acceptable core barrel vibration monitoring program has been temporarily placed on "hold" to permit the NRC staff and its consultants (Oak Ridge National Laboratory Inspection and Enforcement Group) time to evaluate apparently anomalous data from core barrel motion monitoring programs that are currently in service as part of the technical specification requirements for certain licensees.

(4) References:

1. Combustion Engineering, CE Report CEN-5(P), "Palisades Reactor Internals Wear Report," March 1, 1974
2. Regulatory Guide 1.133, "Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors"

TOPIC: III-8.B Control Rod Drive Mechanism Integrity

(1) Definition:

Review and evaluate the reliability, operability and any reported mechanical failures in control rod drives.

(2) Safety Objective:

To assure that the integrity and operability of control rod drives is adequately maintained so that they will be capable of normal reactor control and prompt reactor shutdown, if required.

(3) Status:

The Division of Operating Reactors Engineering Branch is currently evaluating the failure modes and internal component redesigns of BWR control rod drives to preclude stress corrosion and thermal fatigue cracking. There have been no reported generic failures of PWR drives.

(4) Reference:

General Electric, NEDO-21021, "Test Program for Collet Retainer Tube," June 23, 1976.

TOPIC: III-8.C Irradiation Damage, Use of Sensitized Stainless Steel, and Fatigue Resistance

(1) Definition:

Review the safety aspects that affect reactor vessel internals integrity for compliance with 10 CFR Part 50, including radiation damage, use of sensitized stainless steel, and fatigue resistance.

(2) Safety Objective:

To assure continued reactor vessel internals integrity and compliance with 10 CFR Part 50 and applicable industry Codes and Standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, currently has no review programs relating to reactor vessel internals integrity.

(4) References:

1. 10 CFR Part 50, Appendix A
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
3. American Society of Testing Materials, ASTM A-262-70, "Standard Recommended Practices for Detecting Susceptibility to Intergranular Attack in Stainless Steels"
4. Regulatory Guides
   1.37, "Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants"
   1.44, "Control of the Use of Sensitized Stainless Steel"
   1.61, "Damping Values for Seismic Design of Nuclear Power Plants"

TOPIC: III-8.D Core Supports and Fuel Integrity

(1) Definition:

Abnormal loading conditions on the core supports and fuel assemblies due to seismic events or loss-of-coolant accidents (LOCAs) could cause fuel damage due to impact between fuel assemblies and upper- and lower-grid plates or lateral impact between fuel assemblies and the core baffle wall. The resulting damage could result in loss of coolable heat transfer geometry, make it impossible to insert control rods, or cause releases of radioactive materials due to fuel pin failure.

(2) Safety Objective:

To assure that all credible loading conditions on core supports and fuel assemblies will not result in unacceptable fuel damage or distortion.

(3) Status:

The Division of Operating Reactors is currently reviewing the dynamic loads imposed on the fuel assemblies during a LOCA. Independent analyses are being conducted by staff consultants.

(4) Reference:

American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

  USI A-2 requires that an analysis be performed by licensees to assess the design adequacy of the reactor vessel supports and other structures to withstand the loads when asymmetric LOCA forces are taken into account. The staff has completed its investigation and concluded that an acceptable basis has been provided in NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems," January 1981, for performing and reviewing plant analyses for asymmetric LOCA loads. The structural acceptance criteria specified in NUREG-0609 are as follows:

  The structural integrity of the primary system including the reactor pressure vessel, reactor pressure vessel internals, primary coolant loop, and components must be evaluated against appropriate acceptance criteria to determine if acceptable margins of safety exist. Allowable limits and appropriate loading combinations are set forth in Standard Review Plans (SRPs), which are listed in the table that follows. The staff recognizes that in some specific cases where "as-built" designs are being reevaluated for asymmetric LOCA loads, these design limits may be exceeded. Acceptance of alternative allowable limits will be based on a case-by-case evaluation of the safety margins.

  Load-combination criteria in general were not addressed as part of this study. Currently the staff requires that seismic and LOCA response be combined, along with responses due to other loading as specified by the SRP. An acceptable method for combining elastically generated seismic and LOCA responses is provided in NUREG-0484. Acceptable methods for combining response generated by an inelastic LOCA analysis and elastic seismic analyses will be evaluated on a case-by-case basis.

  Since USI A-2 also requires the investigation of seismic and LOCA response be combined, the evaluation required by USI A-2 is identical to SEP Topic III-8.D; therefore, this SEP topic has been deleted.

Item	SRP Se..ion
Reactor pressure vessel	3.9.3
Reactor internals	3.9.5, 3.9.1
Primary coolant loop piping	3.9.3
ECCS piping	3.9.3
RPV, SG, pump supports	3.8.3
Biological shield wall	3.8.3
Steam-generator compartment wall	3.8.3
Neutron-shield tank	3.8.3

TOPIC: III-9 Support Integrity

(1) Definition:

Review the design, design loads, and materials integrity including corrosion and fracture toughness and the inservice inspection programs of supports and restraints including bolting for the reactor vessel, steam generator, reactor coolant pump, torus, and other Class 1, 2, and 3 safety-related components and piping systems.

(2) Safety Objective:

To assure adequate support and/or restraint of safety-related systems and components under normal and accident loads so that they will not be prevented from performing their intended functions because of support failures.

(3) Status:

The Division of Operating Reactors has ongoing programs to review component supports. Current emphasis is on primary system supports and on piping system supports and restraints (snubbers).

(4) References:

1. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III
2. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Topics 3-5 and 3-43

(5) Basis for Deletion (Related TMI Task, USI, or other SEP Topic):

(a) USI A-12, "Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports" (NUREG-0510 and NUREG-0606)

The original scope of USI A-12 was the review of the steam generator and reactor coolant pump supports of pressurized water reactors.

However, the staff has expanded the review to include other support structures, such as boiling water reactor (BWR) vessel supports, BWR pump supports, pressurized water reactor (PWR) vessel supports and PWR pressurizer supports (NUREG-0577, Section 1.3). This expanded review will be undertaken in accordance with the guidance of Section 4 of NUREG-0577.

(b) USI A-7, "MARK I Containment Long-Term Program" (NUREG-0649)

Support integrity of the torus is being evaluated under USI A-7. Under this task, a short-term program that evaluated Mark I containment has provided assurance that the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated loss-of-coolant accident. A longer term program for BWR facilities, not yet licensed, is planned wherein the NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owners Group prior to the performance of plant-unique structural evaluations. The Mark I Owners Group has initiated a comprehensive testing and evaluation program to define design-basis loads for the Mark I containment system and to establish structural acceptance criteria which will assure margins of safety for the containment system which are equivalent to that which is currently specified in the ASME Boiler and Pressure Vessel Code. Also included in their program is an evaluation of the need for structural modifications and/or load mitigation devices to assure adequate Mark I containment system structural safety margins.

(c) USI A-24, "Qualification of Class 1E Safety-Related Equipment" (NUREG-0371 and NUREG-0606)

Snubber operability and degradation of seals are covered under USI A-24.

(d) USI A-46, "Seismic Qualification of Equipment in Operating Plants" (NUREG-0705)

Mechanical snubbers are covered under USI A-46.

(e) SEP Topic III-6, "Seismic Design Considerations"

Snubbers are evaluated for capacity under SEP Topic III-6.

(f) SEP Topic V-1, "Compliance With Codes and Standards (10 CFR 50.55a)"

Inservice inspection requirements for supports are covered under SEP Topic V-1, which refers to 10 CFR 50.55a. SEP plants currently have surveillance Technical Specifications on snubbers.

The evaluation required by USI A-12, A-7, A-24, and A-46 and SEP Topics III-6 and V-1 is identical to the evaluation required by SEP Topic III-9; therefore, this SEP topic has been deleted.

TOPIC: III-10.A Thermal-Overload Protection for Motors of Motor-Operated Valves

(1) Definition:

The primary objective of thermal overload relays is to protect motor windings of motor-operated valves (MOVs) against excessive heating. This feature of thermal overload relays could, however, interfere with the successful functioning of a safety-related system. In nuclear plant safety system application, the ultimate criterion should be to drive the valve to its proper position to mitigate the consequences of an accident, rather than to be concerned with degradation or failure of the motor due to excess heating.

(2) Safety Objective:

To assure that (1) thermal overload protection, if provided for MOVs, should have the trip setpoint at a value high enough to prevent spurious trips due to design inaccuracies, trip setpoint drift, or variation in the ambient temperature at the installed location; (2) the circuits which bypass the thermal overload protection under accident conditions should be designed to IEEE Std. 279-1971 criteria, as appropriate for the rest of the safety-related system; and (3) in MOV designs that use a torque switch instead of a limit switch to limit the opening or closing of the valve, the automatic opening or closing signal should be used in conjunction with a corresponding limit switch and thermal overload should remain as backup protection.

(3) Status:

The staff position (Reference 1) is implemented on designs of new applications (construction permit and operating license).

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB 27, "Design Criteria for Thermal Overload Protection for Motors of Motor-Operated Valves"
2. Institute of Electrical and Electronics Engineers, IEEE Std. 279-1971, Criteria for Protection System for Nuclear Power Generating Stations"
3. Regulatory Guide 1.106, "Thermal Overload Protection for Electric Motors on Motor-Operated Valves"

TOPIC: III-10.B Pump Flywheel Integrity

(1) Definition:

Review the PWR reactor coolant pump flywheel inservice inspection programs of operating plants to assure that they comply with the intent of Regulatory Guide 1.14 and review reports of flywheel flaws if found by inservice inspections. (BWR reactor coolant pumps do not have flywheels.)

(2) Safety Objective:

To assure that pump flywheel integrity is maintained to prevent failure at normal operating speeds and at speeds that might be reached under accident conditions and thus preclude the generation of missiles.

(3) Status:

The inservice inspection programs for flywheels of older PWRs have not been reviewed for compliance with the intent of Regulatory Guide 1.14.

(4) Reference:

Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity"

TOPIC: III-10.C Surveillance Requirements on BWR Recirculation Pumps and Discharge Valves

(1) Definition:

At facilities which have completed the low pressure coolant injection system (LPCIS) modification, the recirculation pump discharge valves and bypass valves are now required to close upon initiation of LPCIS. The closure of these discharge valves is necessary to isolate a pipe break in a suction line to prevent loss of cooling water by reverse flow through the recirculation pump or its bypass line and out the break.

(2) Safety Objective:

To assure effective core cooling in the event of a BWR recirculation line break on the pump suction line by closing the pump discharge valve and bypass line valve.

(3) Status:

All licensees of facilities with completed LPCIS modification have been sent letters requesting that they apply for a license amendment to incorporate technical specification surveillance requirements on recirculation pump discharge valves and bypass valves. New BWRs have the LPCIS modification and technical specification surveillance requirements.

(4) Reference:

NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) Issue 3-46, June 17, 1977

TOPIC: III-11 Component Integrity

(1) Definition:

Review licensee's criteria, testing procedures, and dynamic analyses employed to assure the structural integrity and functional operability of safety-related mechanical equipment under faulted conditions and accident loads. Included are mechanical equipment such as pumps, valves, fans, pump drives, heat exchanger tube bundles, valve actuators, battery and instrument racks, control consoles, cabinets, panels, and cable trays.

(2) Safety Objective:

To confirm the ability of safety-related mechanical equipment having experienced problems to function as needed during and after a faulted or accident condition. The capability of safety-related mechanical equipment to perform necessary protective actions is essential for plant safety.

(3) Status:

This review is not currently under way in the Divisions of Operating Reactors.

(4) References:

1. 10 CFR Part 50, Section 50.55a
2. 10 CFR Part 50, Appendix A, GDC 2, 4, 14, and 15
3. Standard Review Plan, Section 3.9.2
4. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III,
5. Regulatory Guides
   1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing"
   1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants"
6. Institute of Electrical and Electronics Engineers, IEEE Std. 344-1975, "Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations"
7. Standard Review Plan, Section 3.9.3

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-46, "Seismic Qualification of Equipment in Operating Plants" (NUREG-0606 and NUREG-0705)

The component integrity (both structural integrity and functional operability) for safety-related mechanical and electrical equipment for all operating plants including SEP plants will be addressed in this new USI (A-46).

(b) USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

The assessment of faulted loads for the primary loop is being performed under USI A-2. Furthermore, the assessment of high-energy pipe breaks considers the effect of accident loads with regard to jet impingement, pipe whip, and other reaction loads.

(c) SEP Topic III-6, "Seismic Design Considerations"

The evaluation of equipment structural integrity under seismic loads will be performed under SEP Topic III-6.

The evaluations required by USI A-46 and A-2 and SEP Topic III-6 are identical to SEP Topic III-11; therefore, this SEP topic has been deleted.

TOPIC: III-12 Environmental Qualification of Safety-Related Equipment

(1) Definition:

Safety-related electrical and mechanical equipment that is required to survive and function under environmental conditions calculated to result from a loss-of-coolant accident (LOCA) or a postulated main steam line break accident inside containment must be environmentally qualified. In addition, determine whether environment-induced failures of nonsafety-related equipment could interfere with the operation of safety equipment. Special attention should be given to the effect of beta radiation on exposed organic surfaces, such as gaskets.

(2) Safety Objective:

To assure that the mechanical and Class IE electrical equipment of safety systems has been qualified for the most severe environment (temperature, pressure, humidity, chemistry, and radiation) of design basis accidents.

(3) Status:

Westinghouse is conducting a verification program which is expected to be completed by the end of 1977 for those plants qualified to IEEE 323-1971. The Office of Nuclear Regulatory Research is sponsoring programs relating to Class IE equipment qualification, the results of which can be utilized to determine the adequacy of the equipment previously qualified.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue 25, "Qualification of Safety-Related Equipment," December 1976
2. Division of Operating Reactors, DOR Technical Activities, Category B, Item 34, "Environmental Qualifications of Safety-Related Equipment (Post LOCA)," May 1977
3. Division of Systems Safety, DSS Technical Activities, Category A, Item 33, "Qualification of Class IE Safety-Related Equipment," April 1977
4. Regulatory Guide 1.89, "Qualification of Class IE Equipment for Nuclear Power Plants"

(5) Basis for Deletion (Related TMI Task, USI, or other SEP Topic):

USI A-24, "Qualification of Class IE Safety-Related Equipment" (NUREG-0371 and NUREG-0606)

The issue identified in Reference 1 (NUREG-0153, Item 25) and the review criteria, that is, Regulatory Guide 1.89, are identical to those specified in USI A-24. The Task Action Plan for USI A-24

(NUREG-0371) covers the environmental qualification of both electrical and mechanical safety-related equipment.

The evaluation required by USI A-24 is identical to SEP Topic III-12; therefore, this SEP topic has been deleted.

TOPIC: IV-1.A Operation With Less Than All Loops in Service

(1) Definition:

A number of BWR and PWR licensees have requested authorization to operate with one of the recirculation loops (BWR) or steam generator loops (PWR) out of service. These proposals are being reviewed generically with regard to analytical methods. Plant-specific reviews will be done to determine appropriate Technical Specification limits. Plant-specific reviews will address results of LOCA analyses using generically approved methods. Analysis of accidents (other than LOCA) and operating transients resulting from operation in the (N-1) loop mode have been reviewed on a "lead plant basis." Most of this effort has been completed. Tests have been conducted by General Electric which show that significant core flow asymmetries do not exist with single-loop operation for two-loop plants; however, there is backflow through inactive jet pumps. Therefore, for single-loop operation, modifications are necessary in trip settings which take inputs from jet pump drive flow. These will be determined on a plant-specific basis.

(2) Safety Objective:

To provide assurance that operation with less than all coolant loops in operation will not result in decreased safety margins.

(3) Status:

A combination of generic and plant-specific reviews is being performed on both BWRs and PWRs.

TOPIC: IV-2 Reactivity Control Systems Including Functional Design and Protection Against Single Failures

(1) Definition:

General Design Criterion 25 requires that the reactor protection system be designed to assure that fuel-damage limits are never exceeded in the event of any single failure of the reactivity control systems. Reactivity control systems need not be designed single failure proof, but the protection system (which is designed against single failures) should be capable of limiting fuel damage in the event of a reactivity control system single failure.

(2) Safety Objective:

To assure that for all credible reactivity control system failures, the protection system will limit fuel damage to acceptable limits.

(3) Status:

NRC has concluded that revisions to existing licenses are not warranted. Staff effort on this issue will continue at a low level.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 6, "Protection Against Single Failures in Reactivity Control Systems," December 1976.
2. Standard Review Plan, Section 15.4.3

TOPIC: IV-3 BWR Jet Pump Operating Indications

(1) Definition:

If a jet pump BWR operates with a failed jet pump, it may be impossible to reflood the core in the event of a LOCA. Some BWRs have experienced jet pump instrument sensing line failures. With a sensing line failed, it may not be possible to accurately measure core flow or to detect failure of a jet pump.

(2) Safety Objective:

To assure that the core flow can be determined. Also to assure the ability to detect a jet pump failure for a range of crack/break sizes at various locations on the pump.

(3) Status:

This issue is currently being reviewed for Dresden Units 2 and 3 and Quad Cities Units 1 and 2. The topic has generic implications for all jet pump BWR plants.

(4) References:

1. Letters from Commonwealth Edison Company to NRC, dated September 19, 1975, March 3, 1976, and June 7, 1976.
2. Letter from NRC to Commonwealth Edison Company, dated January 19, 1976.
3. Memorandum from J. H. Sniezek, NRC, to D. L. Ziemann, dated November 19, 1975.

TOPIC: V-1 Compliance With Codes and Standard (10 CFR 50.55a)

(1) Definition:

Review the licensee's inservice inspection and testing programs for Class 1, 2, and 3 pressure vessels, piping, pumps and valves and other safety-related components to assure compliance with the American Society of Mechanical Engineers (ASME) Code, Sections III and XI, as required by 10 CFR 50.55a. This review will also include review of the inservice inspection and testing program applicable to isolation condensers of the early operating BWRs.

(2) Safety Objective:

To assure that the initial integrity of components is maintained throughout service life.

(3) Status:

NUREG-0081 was completed for reactor vessels not designed to ASME Code, Section III. The Engineering Branch conducts a generic review of all plants for compliance with inspection requirements of 10 CFR 50.55a(g) and fracture toughness requirements of 10 CFR 50.55a(i). This program will continue for the life of operating reactors.

(4) References:

1. 10 CFR Part 50, Section 50.55a
2. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Sections III and XI
3. NUREG-0081, "Evaluation of the Integrity of Reactor Vessels Designed to ASME Code, Section I and/or VIII," July 1976
4. Memorandum from V. Stello, NRC, to B. H. Grier, October 12, 1976

TOPIC: V-2 Applicability of Code Cases

(1) Definition:

Review Code Cases currently accepted by the NRC, as indicated in Regulatory Guides 1.84 and 1.85.

(2) Safety Objective:

To assure that only those Code Cases which are acceptable to the NRC are utilized by the licensee in the design, fabrication, or repair of the plant. The use of Code Cases other than those contained in Regulatory Guides 1.84 and 1.85 are addressed on a case-by-case basis to assess their acceptability.

(3) Status:

The Engineering Branch, Division of Operating Reactors, routinely reviews design modifications and component repairs (for example, reactor vessel nozzles) to assure compliance with NRC acceptable Code Cases. The program is ongoing on an as-needed basis.

(4) References:

Regulatory Guides
1.84, "Design and Fabrication Code Case Acceptability - ASME Section III, Division 1"
1.85, "Materials Code Case Acceptability - ASME Section III, Division 1"

TOPIC: V-3 Overpressurization Protection

(1) Definition:

Inadvertent overpressurization of the primary system at temperatures below the nil ductility transition temperature may result in reactor vessel failure during heatup and pressurization. Such overpressure transients are caused by pressure surges when the primary system is water solid. The most severe transients have occurred when a charging pump starts up or inadvertent closing of a letdown valve with a charging pump running. Pressure temperature limits as a function of neutron fluence of the material at the reactor vessel beltline are specified in 10 CFR 50, Appendix G. All PWR licensees have been directed to institute interim administrative procedures to prevent damaging pressure transients and on a longer time scale to provide permanent protection which will probably include hardware changes such as high-capacity safety relief valves.

(2) Safety Objective:

To protect the primary system from potentially damaging overpressurization transients during plant pressurization and heatup.

(3) Status:

Generic review of all PWR licensee submittals is under way. Criteria for evaluation have been developed and refined by the Office of Nuclear Reactor Regulation and the Office of Nuclear Regulatory Research. An effort is being made to complete the review sufficiently early to ensure installation of mitigating systems by the end of 1977.

(4) Reference:

NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR to NRR Staff," November 1976

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-26, "Reactor Vessel Pressure Transient Protection" (NUREG-0410)

  Under USI A-26, licensees were requested to modify their systems and procedures to protect against low temperature overpressurization. All operating PWRs have made these modifications, and safety evaluation reports for the SEP plants have been issued.

  The evaluation required by USI A-26 is identical to SEP Topic V-3; therefore, this SEP topic has been deleted.

TOPIC: V-4 Piping and Safe-End Integrity

(1) Definition:

Review the safety aspects that affect BWR and PWR piping and safe-end integrity for compliance with 10 CFR Part 50, including fracture toughness, flaw evaluation, stress corrosion cracking in BWR and PWR piping, and control of materials and welding.

(2) Safety Objective:

To ensure continued piping integrity and compliance with 10 CFR Part 50 and applicable industry codes and standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, is conducting an ongoing program that includes the as-needed review of those aspects necessary to ensure the continuing integrity of piping systems important to safety including stress corrosion cracking of BWR coolant pressure boundary piping. This program will continue for the life of operating reactors.

(4) Reference:

American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section XI

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-42, "Pipe Cracks in Boiling Water Reactors" (NUREG-0510)

The scope of USI A-42 is the study of stress corrosion cracking in BWR piping. NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," is the resolution of USI A-42 and presents staff positions.

(b) USI A-10, "BWR Feedwater Nozzle Cracking and Control Rod Drive Hydraulics Return Line Nozzle Cracking" (NUREG-0649)

(c) NRR Generic Activity C-7, "PWR System Piping" (NUREG-0471)

The scope of this activity is the study of stress corrosion cracking in PWR piping. NUREG-0691, "Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," recommends the same corrective actions (pp. 2-12) proposed for BWRs in NUREG-0313, Revision 1, USI A-42.

The evaluation required by USI A-42 and Task C-7 is identical to the evaluation required by SEP Topic V-4; therefore, this SEP topic has been deleted.

TOPIC: V-5 Reactor Coolant Pressure Boundary (RCPB) Leakage Detection

(1) Definition:

Reactor primary coolant leakage detection systems are a significant means of preventing primary system boundary failure by identifying leaks before failures occur.

(2) Safety Objective:

To provide reliable and sensitive leakage detection systems to identify primary system leaks at an early stage before failures occur.

(3) Status:

This issue has been resolved for all plants which have recently received an operating license by requiring conformance to Regulatory Guide 1.45. Individual older plants have not been systematically reviewed and leakage detection systems may need upgrading on a plant-by-plant basis.

(4) References:

1. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems"
2. Standard Review Plan, Section 5.2.5

TOPIC: V-6 Reactor Vessel Integrity

(1) Definition:

Review the safety aspects that affect BWR and PWR reactor vessel and nozzle integrity for compliance with 10 CFR Part 50, including fracture toughness, neutron irradiation, evaluation of surveillance programs, operating limitations, inservice inspection and flaw evaluation, and transient analyses.

(2) Safety Ojective:

To assure continued reactor vessel integrity and compliance with 10 CFR Part 50 and applicable industry codes and standards.

(3) Status:

The Engineering Branch, Division of Operating Reactors, is conducting ongoing programs that include the periodic review of aspects necessary to ensure the continued integrity of reactor vessels. These programs include BWR feedwater and control rod drive nozzle cracking, low upper-shelf toughness, radiation effects, reactor vessel materials surveillance, and updating of operating plants' inservice inspection programs and will continue for the life of operating reactors.

(4) References:

1. NUREG-0312, "Interim Technical Report on BWR Feedwater and Control Rod Drive Return Line Nozzle Cracking," July 1977
2. 10 CFR Part 50, Appendix G
3. Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials"
4. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section III, Appendix G
5. American Society of Testing Materials, ASTM E185, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels"

6. American Society of Mechanical Engineers, "Boiler and Pressure Vessel Code," Section XI
7. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Issue 3-9, 3-21, 3-41

TOPIC: V-7 Reactor Coolant Pump Overspeed

(1) Definition:

Review the potential for reactor coolant pumps to fail because of overspeed in the unlikely event of a major loss-of-coolant accident (LOCA).

(2) Safety Objective:

To assure that, in the event of a major LOCA, a reactor coolant pump assembly is not driven to a speed which would cause structural failure of the unit and result in missiles which could increase the consequences of the LOCA. Of greatest concern are the PWR pump flywheels because of their mass and rotational energy.

(3) Status:

An indepth review of this topic was performed by the Atomic Energy Commission staff and reported to the Advisory Committee on Reactor Safeguards (ACRS) in 1973 (Reference 1). The staff concluded that, because of the small likelihood for the occurrence of a pump overspeed event that could seriously increase the consequences resulting from a LOCA (less than 10-8 per plant year), the action taken by the staff to assess this problem in a generic fashion outside the context of individual application reviews is an acceptable course to follow. A generic experimental program to be completed in 1978 by the Electric Power Research Institute is expected to provide data to verify pump model overspeed predictions.

(4) References:

1. Letter from R. C. DeYoung, NRC, to Harold G. Mangelsdorf, ACRS, August 6, 1973, transmitting "Report on Reactor Coolant Pump Overspeed During a LOCA," August 3, 1973.
2. Regulatory Guide 1.14, "Reactor Coolant Pump Flywheel Integrity"

TOPIC: V-8 Steam Generator (SG) Integrity

(1) Definition:

Review the safety aspects affecting operation of steam generators including secondary water chemistry, tube plugging criteria, inservice inspection, possibly including a dimensional inspection for proper evaluation of denting, steam generator tube leakage, tube denting, flow-induced vibration of steam generator tubes, tube repair, and tube bundle or steam generator replacement.

(2) Safety Objective:

To ensure that acceptable levels of integrity of that portion of the reactor coolant pressure boundary made up by the steam generator are maintained in accordance with current codes, standards, and/or regulatory criteria during normal and postulated accident conditions. The integrity of the steam generator is needed to ensure that leakage following a postulated design basis accident will not result in doses to the public in excess of 10 CFR Part 100 guidelines and that the emergency core cooling systems will be able to perform their safety functions.

(3) Status:

Review of this topic is being performed by the Division of Operating Reactors (DOR). This effort will continue for the life of operating reactors.

(4) References:

1. Regulatory Guide 1.83, Rev. 1, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes"
2. Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes"
3. 10 CFR Part 50, Appendix A, GDC 30 and 32
4. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), 3-27

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-3, A-4, A-5, "Westinghouse, Combustion Engineering, and Babcock and Wilcox Steam Generator Tube Integrity" (NUREG-0649)

The definition of this topic and the references cited are covered by USI A-3, A-4, and A-5. The evaluation for USI A-3, A-4, and A-5 is identical to SEP Topic V-8; therefore, this SEP topic has been deleted.

TOPIC: V-9 Reactor Core Isolation Cooling System (BWR)

(1) Definition:

Reactor core isolation cooling (RCIC) has not been classified as a safety system. On GESSAR, for certain small breaks, GE assumed credit for RCIC as a backup for HPCI. The staff required GE to reclassify the RCIC system on the GESSAR 238 standard NSSS as a safety system.

(2) Safety Objective:

To ensure that the RCIC system is qualified as a safety system where credit is assumed in the safety analysis.

(3) Status:

GE has agreed to reclassify RCIC as a safety system on the GESSAR docket.

TOPIC: V-10.A Residual Heat Removal System Heat Exchanger Tube Failures

(1) Definition:

Residual heat removal (RHR) heat exchangers are designed to remove residual and decay heat so that the reactor can be placed in a safe cold shutdown condition and to maintain core cooling following a postulated loss-of-coolant accident. Some light-water reactors (LWRs) have a pressure control system on the cooling water piping system which maintains the pressure of the cooling water higher than the primary coolant pressure in the primary coolant side of the heat exchanger during plant cooldown operations. A leak in the tubes could result in back leakage of coolant water into the primary loop. Pressure in the cooling water side is maintained higher than that in the primary coolant side so that in the event of a tube failure there would be no leakage of radioactive fluids into the environment. Cooling water passing from the cooling water side of the heat exchanger into the primary coolant water could introduce impurities such as chlorides into the primary coolant system.

(2) Safety Objective:

To assure that impurities from the cooling water system are not introduced into the primary coolant in the event of an RHR heat exhanger tube failure.

(3) Status:

Recently there have been several RHR heat exchanger tube failures at operating BWRs. This issue has been defined as a DOR Category B Technical Activity.

TOPIC: V-10.B Residual Heat Removal System Reliability

(1) Definition:

In all current plant designs, the residual heat removal (RHR) system has a lower design pressure than the reactor coolant system (RCS). In most current designs, the system is located outside of containment and is part of the emergency core cooling system. However, it is possible for the RHR system to have different design characteristics. For example, the RHR system might have the same design pressure as the RCS, or be located inside of containment. The functional, isolation, pressure relief, pump protection, and test requirements for the RHR system are of concern in the safety review of reactor plants. Three types of RHR system designs are defined in Branch Position RSB 5-1.

On June 24, 1976, the Regulatory Requirements Review Committee approved a revision of Standard Review Plan, Section 5.4.7 requiring a capability to go from hot to cold shutdown without offsite power and that all components necessary for cooldown from hot shutdown must be designed to safety grade seismic I standards, and be operable from the control room. System must be designed to meet the single failure criterion.

(2) Safety Objective:

To ensure reliable plant shutdown capability using safety-grade equipment.

(3) Status:

Because of vendor concern over the impact of the revision, a review was conducted of three PWR plants, and as a result of this review, the staff is proposing that Branch Position RSB 5-1 be modified but that the functional requirements be retained.

(4) References:

1. Standard Review Plan, Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System"
2. Standard Review Plan, Section 5.4.7
3. Memorandum from E. G. Case, NRC, to L. V. Gossick, July 15, 1976.
4. Summary of meeting September 22, 1976, "Capability To Achieve Cold Shutdown Using Safety Grade Systems and Equipment," C. O. Thomas, Docket No. STN-50-545, October 5, 1976.

TOPIC: V-11.A Requirements for Isolation of High- and Low-Pressure Systems

(1) Definition:

Several systems that have a relatively low design pressure are connected to the reactor coolant pressure boundary. The valves that form the interface between the high- and low-pressure systems must have sufficient redundancy and interlocks to assure that the low-pressure systems are not subjected to coolant pressures that exceed design limits. The problem is complicated since under certain operating modes (for example, shutdown cooling and emergency core cooling system injection), these valves must open to assure adequate reactor safety.

(2) Safety Objective:

To assure that adequate measures are taken to protect low-pressure systems connected to the primary system from being subjected to excessive pressure which could cause failures and in some cases potentially cause a loss-of-coolant accident outside of containment.

(3) Status:

A preliminary review of a representative operating plant of each nuclear steam supply system vendor was undertaken. Each low-pressure system connected to the reactor coolant pressure boundary and penetrating the containment was examined. The investigation of a few potential areas of concern is continuing.

TOPIC: V-11.B Residual Heat Removal System Interlock Requirements

(1) Definition:

The residual heat removal (RHR) system is normally located outside of primary containment. It is an intermediate pressure system (usually 600 psia) and has motor-operated valve (MOV) isolation valves connecting it to the reactor coolant system (RCS). If the RHR system were inadvertently connected to the RCS while the RCS is at pressure, a loss-of-coolant accident (LOCA) could result with a loss of all capability of core reflooding since the coolant inventory could be lost outside of containment. To prevent inadvertent opening of the MOVs while the RCS is at pressure, an "OPEN PERMISSIVE" interlock is provided.

If the operator shuts only one of the isolation valves prior to pressurizing the RCS, there is a single valve RCS pressure boundary.

To ensure that both MOVs are shut during a startup and heatup, an "AUTO-CLOSURE" interlock is provided that closes the MOVs.

(2) Safety Objective:

To ensure that operating reactor plants are adequately protected from overpressurizing the RHR system and potentially causing a LOCA outside of containment.

(3) Status:

Several PWR plants do not have the auto closure feature on the RHR, and at least one does not have the open permissive feature. Plants should be reviewed on a case-by-case basis factoring in (1) ASME Code safety valve setting and capacity, (2) interlocks, (3) closure time of MOVs, and (4) location of RHR.

(4) References:

1. Proposed Branch Technical Position RSB-5-1, "Design Requirements of the Residual Heat Removal System"
2. Regulatory Requirements Review Committee Meeting No. 50, June 24, 1976
3. 10 CFR Part 50, Appendix A, GDC 34
4. Memorandum from J. Angelo to R. C. DeYoung, V. Stello, et al., NRC, Subject: "RP-TR Staff Meeting of February 13, 1974 Regarding the Requirements on Shutdown Cooling Systems," February 28, 1974
5. Letter from R. Boyd, NRC, to C. Eicheldinger, Westinghouse Electric Corporation, November 12, 1975
6. Letter from R. Boyd, NRC, to I. Stuart, General Electric Company, November 12, 1975
7. Letter from R. Minogue, NRC, to J. D. Geier, Illinois Power Company, July 8, 1975

TOPIC: V-12.A Water Purity of BWR Primary Coolant

(1) Definition:

Review the primary water monitoring and reactor water cleanup system capabilities, including the water purity, to determine if the maintenance of the necessary purity levels complies with Regulatory Guide 1.56. Review limits on quality control and defined provisions in the event of demineralizer breakthrough.

(2) Safety Objective:

To assure that the water purity level is acceptably low to minimize the potential for intergranular stress corrosion cracking of austenitic stainless steel piping in the reactor coolant pressure boundary of BWRs, including assuring the implementation of Regulatory Guide 1.56.

(3) Status:

Recommendations for specifying the use of additional conductivity measurements and monitoring at various locations, plus the use of pH and chloride measurements, have been submitted to the Division of Standards Development to initiate a revision of Regulatory Guide 1.56, "Maintenance of Water Purity in Boiling Water Reactors," dated June 1973. To date, a generic review of operating BWRs has not been initiated and the current regulatory guide has been implemented in the Technical Specifications of only a few operating plants.

(4) Reference:

Memorandum from R. E. Heineman, to R. B. Minogue, NRC, Subject: "Request for Revision of Regulatory Guide 1.56," 1973

TOPIC: V-13 Waterhammer

(1) Definition:

Waterhammer events have occurred in light water reactor systems. Waterhammer events increase the probability of pipe breaks and could increase the consequences of certain events such as the loss-of-coolant accident. The types of waterhammer, the vulnerable systems (for example, containment spray, service water, feedwater, and steam), and the safety significance of waterhammer have been identified and defined in a staff report of May 1977.

(2) Safety Objective:

To reduce the probability of waterhammer events that have the potential to lead to pipe ruptures in light-water reactor systems which are needed to mitigate the consequences of accidents or that might increase the consequences of accidents previously analyzed.

(3) Status:

Generic review is under way. On March 10, 1977, an interdivisional Division of Operating Reactors/Division of Systems Safety technical review group was formed to investigate the waterhammer issue and to develop a program for its appropriate consideration in licensing reviews and for operating reactors. Consultant work has been performed by CREARE and Livermore Labs.

(4) References:

1. "Water Hammer in Nuclear Power Plants," NRC Staff Report, June 1, 1977
2. Wallis, G. B., P. H. Rothe, et al., "An Evaluation of PWR Steam Generator Water Hammer" (draft), CREARE Inc., February 1977
3. Sutton, S. B., "An Investigation of Pressure Transient Propagation in Pressurized Water Reactor Feedwater Lines" (preliminary), Lawrence Livermore Laboratory, April 15, 1977
4. Office of Nuclear Reactor Regulation, NRR Technical Activities, Category A, Item 1, "Water Hammer," May 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-1, "Water Hammer" (NUREG-0649)

  The references cited in this topic were the precursors of USI A-1. The evaluation required for USI A-1 is identical to SEP Topic V-13; therefore, this SEP topic has been deleted.

TOPIC: VI-1 Organic Materials and Postaccident Chemistry

(1) Definition:

(a) Organic materials
The design basis for selection of paints and other organic materials is not documented for most operating reactors. Therefore, there is a need to review the suitability of paints and other organic materials used inside containment, including the possible interactions of the decomposition products of organic materials with engineered safety features (such as filters).

(b) Postaccident chemistry
Low pH solutions that may be recirculated within containment after a design basis accident (DBA) may accelerate chloride stress corrosion cracking which may lead to equipment failure or loss of containment integrity. Low pH may also increase the volatility of dissolved iodines with a resulting increase in radiological consequences.

(2) Safety Objective:

(a) Organic materials
To assure that organic paints and coatings used inside containment do not behave adversely during accidents when they may be exposed to high radiation fields. In particular, the possibility of coatings clogging sump screens should be minimized.

(b) Postaccident chemistry
To assure that appropriate methods are available to raise or maintain the pH of solutions expected to be recirculated within containment after a DBA.

(3) Status:

No work currently being done on this subject for operating plants.

(4) References:

1. Standard Review Plan, Sections 6.1.2 and 6.1.3
2. Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants"

TOPIC: VI-2.A Pressure-Suppression-Type BWR Containments

(1) Definition:

BWR pressure-suppression-type containments (for example, Mark I containment) are subjected to hydrodynamic loads during the blowdown phase of a loss-of-coolant accident (LOCA). These loads have the potential for damaging the components and structures (wetwell, internal structures, restraints, supports, and connected systems) of the containment. During a relief valve blowdown into the suppression pool, the wetwell (torus) shell and safety/relief valve restraints may be overstressed. The hydrodynamic loads were not explicitly identified and included in the design of the Mark I pressure-suppression containment.

(2) Safety Objective:

To assure that the structural integrity of pressure-suppression pool containments is maintained under hydrodynamic loading conditions. It has been determined that the upward forces during the blowdown phase following a LOCA potentially cause the Mark I torus to be lifted, causing failure of connecting systems and supports and leading to loss of the containment integrity. Structural modifications and/or changes in the mode of operation might be necessary to assure adequate safety margins.

(3) Status:

Mark I containments are currently evaluated in a two-step generic review program: The Short-Term Program (STP), completed May 1977, has focused on the determination of the magnitude and significance of hydrodynamic loads. In the Long-Term Program (LTP), to be completed by late 1978, the design basis loads will be finalized and the capability of the containment to withstand the loads within the original design structural margins will be verified. This verification will be based in part on research results from NRC and industry sponsored programs. As a result of the STP, the staff required that Mark I plants be operated with a drywell to wetwell differential pressure of at least 1 psi to reduce the vertical loads. In addition, some licensees have modified the torus support system for additional safety margin.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) - Generic Issues (April 1977)
   a. Mark I Containment - STP Technical Specifications
   b. Mark I Containment Evaluation - STP
   c. Mark I Containment Evaluation - LTP
   d. Mark I Safety/Relief Valve Line Restraints in Torus
2. Division of Operating Reactors, DOR Technical Activities, Category A, April 1977
   a. Item 2, "Mark I Containment STP"
   b. Item 3, "Mark I Containment LTP"
   c. Item 23, "Mark II Containment"
3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 12, "Assessment of Column Buckling Criteria," May 1977
4. Division of Systems Safety, DSS Technical Activities, Category A, Item 31, "Determination of LOCA and SRV Pool Dynamic Loads for Water Suppression Containments," April 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-7, "Mark I Containment Long-Term Program" (NUREG-0649)

  Under this task, a short-term program that evaluated Mark I containment has provided assurance that the Mark I containment system of each operating BWR facility would maintain its integrity and functional capability during a postulated LOCA. A longer term program for BWR facilities, not yet licensed, is planned wherein the NRC staff will evaluate the loads, load combinations, and associated structural acceptance criteria proposed by the Mark I Owners Group prior to the performance of plant-unique structural evaluations. The Mark I Owners Group has initiated a comprehensive testing and evaluation program to define design basis loads for the Mark I containment system and to establish structural acceptance criteria which will assure margins of safety for the containment system which are equivalent to that which is currently specified in the ASME Boiler and Pressure Vessel Code. Also included in their program is an evaluation of the need for structural modifications and/or load-mitigation devices to assure adequate Mark I containment system structural safety margins.

  The long-term program for USI A-7 will assure that all plants with Mark I containments are able to tolerate, without loss of function, the LOCA-induced hydrodynamic loads.

  The evaluation required by USI A-7 is identical to SEP Topic VI-2.A; therefore, this SEP topic has been deleted.

TOPIC: VI-2.B Subcompartment Analysis

(1) Definition:

The rupture of a high energy line inside a containment subcompartment can cause a pressure differential across the walls of the subcompartment. In the case of a rupture of a PWR main coolant pipe adjacent to the reactor vessel, the subcooled blowdown produces pressure differentials in the annulus between the reactor vessel and the shield wall and also within the reactor vessel across the core barrel. This asymmetric pressure distribution generates loads on the reactor vessel support and on reactor vessel internals, on other equipment supports, and on subcompartment structures which have not been analyzed previously for most operating reactors.

(2) Safety Objective:

To assure that the reactor vessel supports, reactor vessel internals, and other equipment supports and subcompartment structures are designed with an adequate margin against failure due to these loads. The failure could result in a loss of emergency core cooling system capability.

(3) Status:

The staff is reviewing the nuclear steam supply system vendor and architect-engineer design codes used to calculate the loads produced by the asymmetric pressure distribution. Analyses have been completed for a limited number of operating plants. The W TMD code is approved. Bechtel, Gilbert, and United Engineering have submitted codes for review.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report," (Pink Book) - Generic Issue, Item 3-5, "Asymmetric LOCA Loads - PWR," April 1977
2. Division of Operating Reactors, DOR Technical Activities, Category A, Item 32, "Asymmetric LOCA Loads (Reactor Vessel Support Problem)," April 1977
3. Division of Systems Safety, DSS Technical Activities, Category A, Item 14, "Asymmetric Blowdown Loads on Reactor Vessel," April 1977
4. Division of Project Management, DPM Technical Activities, Category A, Item 2, "Reactor Vessel Supports (Asymmetric LOCA Loads From Sudden Subcooled Blowdown)," April 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-2, "Asymmetric Blowdown Loads on Reactor Primary Coolant System" (NUREG-0649)

  The references cited in this topic were the precursors of USI A-2. The evaluation required for USI A-2 is identical to SEP Topic VI-2.B (see also SEP Topic III-8.D); therefore, this SEP topic has been deleted.

TOPIC: VI-2.C Ice Condenser Containment

(1) Definition:

Operating experience from the D. C. Cook plant has indicated that sublimation and melting of ice causes a loss of ice inventory and related functional performance problems for the ice condenser system.

(2) Safety Objective:

To assure that a sufficient ice inventory is maintained and to assure the functional performance of the ice condenser system.

(3) Status:

The results of the surveillance program for ice inventory and of the functional performance testing (for example, operation of vent doors) are periodically reviewed by the staff to determine whether the surveillance frequencies should be increased or other action should be taken. Recent surveillance testing indicates that the ice inventory is acceptable and that the D. C. Cook plant can be operated safely for the current fuel cycle. CONTEMPT-4 long-term ice condenser code is expected to be completed by Edgerton, Germeshausen & Grier in October 1977.

(4) Reference:

Division of Operating Reactors, DOR Technical Activities, Category B, Item 53, "Ice Condenser Containments," May 1977

TOPIC: VI-2.D Mass and Energy Release for Postulated Pipe Breaks Inside Containment

(1) Definition:

Review the methods and assumptions of the mass and energy release model, including containment temperatures and pressure response, that were used in previously performed analyses of high-energy line breaks inside containment, including the main steam line break.

(2) Safety Objective:

To assure that design basis conditions (for example, design pressure and temperature) for the containment structure and safety-related equipment are adequate. Determine if the models used in the earlier analyses provide adequate margins of safety when compared with the assumptions and models for current analytical techniques.

(3) Status:

Mass and energy release models, including containment response models, are being reassessed to determine the degree of conservatism in the prediction of the containment pressure and temperature transient resulting from a PWR main steam line break. Application of those models to operating plants is contingent on the results of this reassessment. Mass and energy release models for operating BWR plants are considered in the Mark I Long-Term Program and other BWR review efforts.

(4) References:

1. Division of Operating Reactors, DOR Technical Activities, Category B, May 1977

a. Item 1, "Pipe Break Inside Containment"
b. Item 2, "Mass and Energy Release to Containment"

2. Division of Systems Safety, DSS Technical Activities, Category A, April 1977
   a. Item 7, "Pipe Rupture Design Criteria"
   b. Item 29, "Main Steam Line Break Inside Containment"
3. Division of Systems Safety, DSS Technical Activities Report, Item I-C.B.1, "Mass and Energy Release to Containment," December 1975

TOPIC: VI-3 Containment Pressure and Heat Removal Capability

(1) Definition:

The temperature and pressure conditions inside containment due to a postulated loss-of-coolant accident (LOCA), main steam line or feedwater line break depend on the effectiveness of passive heat sinks and active heat removal systems (for example, containment spray system).

(2) Safety Objective:

To assure that the maximum temperature and pressure following a LOCA, main steam, or feedwater line break have been calculated with conservative assumptions and to assure that the passive heat sinks and active heat removal systems provide the full heat removal capability required to maintain the pressure and temperature below the design pressure and temperature of the containment, of safety-related equipment, and instrumentation inside containment.

(3) Status:

The modified CONTEMPT computer code properly accounts for the condensation of superheated steam on containment passive heat sinks. The effects on the design temperatures within the containment are being studied for plants under licensing review.

(4) References:

1. Standard Review Plan, Section 6.2.1.1.A
2. Division of Systems Safety, DSS Technical Safety Activities Report, December 1975
3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 62, "Effective Operation of Containment Sprays in LOCA," May 1977

TOPIC: VI-4 Containment Isolation System

(1) Definition:

Isolation provisions of fluid system of nuclear power plants limit the release of fission products from the containment for postulated pipe breaks inside containment and thus prevent the uncontrolled release of primary system coolant as a result of postulated pipe breaks outside containment. This must be accomplished without endangering the performance of postaccident safety systems. Review the primary containment isolation provisions, in particular, the containment sump lines and fluid systems penetrating containment. Review the design bases for containment ventilation system isolation valves to determine potential releases from the containment. Review the containment purge mode during normal operation with respect to various accident scenarios and consequences including operation of containment purge valves, closure times, and leak tightness.

(2) Safety Objective:

To assure that the primary containment isolation provisions meet the requirements of 10 CFR 50, Appendix A, General Design Criteria 54 through 57. Some of the operating plants may have too few or too many isolation provisions. Containment purging during normal operation in PWRs has raised a concern regarding the ability of the ventilation system isolation valves to close upon receipt of an accident signal. The use of resilient sealing materials in conjunction with the cycling of these valves has resulted in an increased degradation in the leakage integrity of the valve seats. To assure the adequacy of the maintenance and repair schedule to maintain the leakage integrity of the valves for the service life of the plant. To assure that containment purge operations will not adversely affect the consequences of postulated accidents.

(3) Status:

The functional performance of the sump lines and emergency core cooling systems is being reviewed in conjunction with the Appendix K submittals. Implementation criteria are being developed to apply the requirements of Branch Technical Position CSB 6-4 to containment purging practices and to improve the leakage integrity of ventilation system isolation valves.

(4) References:

1. 10 CFR Part 50, Appendix A, GDC 54 through 57
2. Standard Review Plan, Section 6.4.2
3. Standard Review Plan, Branch Technical Position CSB 6-4, "Containment Purging During Normal Plant Operations"

TOPIC: VI-5 Combustible Gas Control

(1) Definition:

Review the combustible gas control system to determine the capability of the system to monitor the combustible gas concentration in the containment, to mix combustible gases within the containment atmosphere, and to maintain combustible gas concentrations below the combustion limits (for example, by recombination, dilution, or purging). For facilities which share recombiners (portable) between units or sites, determine that the recombiners can be made available within a suitable time. For facilities which utilize purging as a primary means of combustible gas control, determine the radiological consequences of the system operation. Reevaluate hydrogen production and accumulation analysis to consider (1) reduction of Zr/water reaction on the basis of five times the Appendix K calculation amount and (2) potential increases in hydrogen production from corrosion of metals inside containment.

(2) Safety Objective:

To prevent the formation of combustible gas explosive concentrations in the containment or in localized regions within containment, following a postulated accident; to assure that the radiological consequences of the system operation are acceptable.

(3) Status:

Proposed 10 CFR 50.44 would permit a BWR licensee to propose an alternate combustible gas control system in lieu of inerting. Four such proposals for containment atmosphere dilution systems are currently under review, and the COGAP II computer code is being revised to perform the system evaluations.

(4) References:

1. Proposed rule 10 CFR Part 50, Section 50.44
2. Division of Operating Reactors, DOR Technical Activities, Category A, Item 8, "Containment Purge During Normal Operation," April 1977
3. Division of Operating Reactors, DOR Technical Activities, Category A, Item 14, "Inerting Requirements/CAD," April 1977
4. Standard Review Plan, Branch Technical Position CSB 6-2, "Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident"
5. Standard Review Plan, Section 6.2.5

(5) Basis for Deletion (Related TMI TASK, USI, or Other SEP Topic):

(a) TMI Action Plan Task II.B.7, "Analysis of Hydrogen Control" (NUREG-0660)

As a result of TMI Task II.B.7, short- and long-term rulemaking to amend 10 CFR 50.44 has been initiated. The short-term rulemaking (interim rule) requires that all Mark I and Mark II containments be inerted. It also requires that the owners of all plants with other containments perform certain analyses of accident scenarios involving hydrogen releases and furnish the staff with a proposed approach for mitigating these hydrogen releases.

The longer-term rulemaking will address both degraded core and melted core issues. In the area of hydrogen control, it will prescribe requirements that are appropriate for operating plants as well as for plants under construction.

(b) USI A-48, "Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment" (NUREG-0705)

Under USI A-48, a Task Action Plan has been defined and is being developed that encompasses the concerns in the Definition and the Safety Objective of SEP Topic VI-5.

The evaluation required by TMI II.B.7 and USI A-48 is identical to SEP Topic VI-5; therefore, this SEP topic has been deleted.

TOPIC: VI-6 Containment Leak Testing

(1) Definition:

Certain requirements of primary reactor containment leakage testing for water-cooled power reactors as described in Appendix J to 10 CFR Part 50 (issued February 1973) have been found to be conflicting, impractical for implementation, or subject to a variety of interpretations. Review the primary reactor containment leak testing program for operating nuclear plants.

(2) Safety Objective:

To assure that the containment leak testing program provides a conservative assessment of the leakage rate through individual leakage barriers and to assure that proper maintenance and repairs are conducted during the service life of the containment. The testing acceptance criteria are established to ensure that containment leakage following a postulated accident will not result in offsite doses exceeding 10 CFR 100 guidelines.

(3) Status:

A generic review for compliance with Appendix J and the review of requested exemptions to the regulation is currently underway. Proposed revisions to Appendix J to improve the testing requirements are under development.

(4) References:

1. 10 CFR Part 50, Appendix J
2. 10 CFR Part 50, Appendix A, GDC 52 and 53
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-10, "Containment Leak Testing - Appendix J," April 1977
4. Division of Operating Reactors, DOR Technical Activities, Category B, Item 33, "Containment Leak Testing Requirements," May 1977
5. Division of Systems Safety, DSS Technical Activities, Category A, Item 30, "Containment Leak Testing," April 1977

TOPIC: VI-7.A.1 Emergency Core Cooling System Reevaluation To Account for Increased Reactor Vessel Upper Head Temperature

(1) Definition:

Loss-of-coolant accident (LOCA) analyses for all Westinghouse reactors were conducted assuming that the water in the upper head region of the reactor vessel was the same as the inlet water temperature because of a bypass flow from the downcomer to the upper head. Temperature measurements made by Westinghouse indicate that the actual temperature of the upper head fluid exceeds cold leg temperature by 50 to 75% of the difference between hot leg and cold leg (inlet) temperature. All operating reactors were required to resubmit LOCA analyses using hot leg temperature for the upper head volume.

(2) Safety Objective:

To provide revised LOCA analyses with correct upper head temperatures to assure that peak clad temperature limits are not exceeded.

(3) Status:

Revised analyses have been received from all Westinghouse plants. All but three have been reviewed and approved.

TOPIC: VI-7.A.2 Upper Plenum Injection

(1) Definition:

Emergency core cooling system (ECCS) evaluation of Westinghouse two-loop plants was performed assuming that low pressure pumped injection is delivered directly to the lower plenum. However, ECC coolant is delivered directly into the upper plenum. Interaction of the cold injection water with the steam exiting from the core during refill and reflood and the heat transfer effects during the downward passage to the lower plenum have not been adequately considered.

(2) Safety Objective:

To provide assurance that existing analyses with Westinghouse two-loop plants are acceptable either by showing that the present analyses are conservative, or by developing a new ECCS model which considers upper plenum injection.

(3) Status:

The staff met with the licensees and Westinghouse on January 11 and 26, 1977. The staff requested that the licensees formally submit the information presented at the January 26, 1977 meeting. Two Westinghouse reports have been received to date. The staff is continuing to evaluate the problem. Research requested by the Office of Nuclear Reactor Regulation and performed by the Office of Nuclear Regulatory Research in the semiscale facility provided basis for evaluation.

TOPIC: VI-7.A.3 Emergency Core Cooling System Actuation System

(1) Definition:

Review the emergency core cooling system (ECCS) actuation system with respect to the testability of operability and performance of individual active components of the system and of the entire system as a whole under conditions as close to the design condition as practical.

(2) Safety Objective:

To assure that all ECCS components (for example, valves and pumps) are included in the component and system test. To assure that the frequency and scope of the periodic testing are adequate and meet the requirements of General Design Criterion 37.

(3) Status:

New applications (construction permit and operating license) are reviewed in accordance with the Standard Review Plan and the references listed below. No specific activity for operating reactors is in progress.

(4) References:

1. Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Function"
2. Standard Review Plan, Branch Technical Position EICSB-25, "Guidance for the Interpretation of General Design Criterion 37 for Testing the Operability of the Emergency Core Cooling System as a Whole"
3. 10 CFR Part 50, Appendix A, GDC 37

TOPIC: VI-7.A.4 Core Spray Nozzle Effectiveness

(1) Definition:

Core spray systems are designed with a nozzle or a set of nozzles arranged above the core in such a way that, following a LOCA, a spray of water will be distributed over the top of the core so that each fuel bundle will receive a specified minimum flow which will provide adequate core cooling. Recent test data for a single nozzle in a steam environment noted partial or complete collapse of the spray cone and/or a shift in the direction of spray. These effects were not included in earlier full scale spray tests in air.

(2) Safety Objective:

To assure adequate spray cooling following a LOCA.

(3) Status:

The NRC has reviewed and accepted spray system performance for multiple nozzle spray systems, but has not accepted spray systems with a single overhead spray nozzle. Recent tests in Florida on the Big Rock Point spray nozzle indicate incomplete core coverage. As a result of these tests, NRC is requesting further testing by GE of multiple spray nozzles.

(4) References:

1. Letter from K. Goller, NRC, to operating reactor branch chiefs, Subject: "Generic Issue - Effects of Steam Environment on Core Spray Distribution for Non-jet Pump BWRs," December 7, 1976
2. General Electric, GE Topical Report NEDO-10846, "BWR Core Spray Distribution"

TOPIC: VI-7.B Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)

(1) Definition:

Most PWRs require operator action to realign emergency core cooling (ECC) systems for the recirculation mode following a LOCA.

We have been requiring, on an ad hoc basis, some automatic features to realign the ECCS from the injection to the recirculation mode of operation.

(2) Safety Objective:

To increase the reliability of long-term core cooling by not requiring operator action to change system realignment to the recirculation mode.

(3) Status:

A draft Branch Technical Position has been prepared which covers both ECC and containment spray systems. The proposed position is awaiting review by the Regulatory Requirements Review Committee.

(4) Reference:

American National Standards Institute, Draft ANSI Standard N 660, "Proposed American National Standard Criteria for Safety-Related Operator Actions"

TOPIC: VI-7.C Emergency Core Cooling System (ECCS) Single-Failure Criterion and Requirements for Locking Out Power to Valves, Including Independence of Interlocks on ECCS Valves

(1) Definition:

The physical locking out of electrical sources to specific motor-operated valves required for the engineered safety functions of ECCS has been required, based on the assumption that a spurious electrical signal at an inopportune time could activate the valves to the adverse position; for example, closed rather than open, or opened rather than closed. There is some concern that interlock circuitry on ECCS valves may not be independent such that a single failure of an interlock due to equipment malfunction or operator error could defeat more than one interlock and cause the valves to be cycled to the wrong position.

(2) Safety Objective:

To ensure that all power-operated valves which could affect emergency core cooling (ECC) system performance by being in the wrong position have power removed except when in use. This will ensure that ECC systems are not defeated by having a valve in the wrong position.

(3) Status:

The staff plans to reconsider EICSB BTP-18 and RSB BTP-6-1.

TOPIC: VI-7.C.1 Appendix K--Electrical Instrumentation and Control Re-reviews

(1) Definition:

During the Appendix K reviews of some facilities initially considered, a detailed electrical instrumentation and control review was not performed. Re-review the modified ECCS of these facilities to confirm that it is designed to meet the most limiting single failure.

(2) Safety Objective:

To assure that the modified ECCS is designed to meet the most limiting (design basis) single failure.

(3) Status:

No current activity in the Division of Operating Reactors.

(4) References:

1. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems"
2. Institute of Electrical and Electronics Engineers, IEEE Std. 308, "Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"

TOPIC: VI-7.C.2 Failure Mode Analysis (Emergency Core Cooling System)

(1) Definition:

Failure modes and effects criticality analyses (FMECA) would be conducted for the purpose of systematically determining potential single failures in emergency core cooling (ECC) systems.

(2) Safety Objective:

To determine if single failures exist in ECC system as an aid in assessing overall plant safety.

(3) Status:

FMECAs have been conducted on the hydraulic portion of ECC systems of representative plant types. In addition, single-failure analyses were performed on each plant as a part of the required Appendix K analysis except for those plants with stainless steel clad cores.

TOPIC: VI-7.C.3 Effect of PWR Loop Isolation Valve Closure During a Loss-of-Coolant Accident on Emergency Core Cooling System Performance

(1) Definition:

Some PWRs are equipped with loop isolation valves. The effect of spurious closure of a loop isolation valve during a LOCA has never been analyzed. To ensure emergency core cooling system (ECCS) performance, power in some cases has been removed from loop isolation valves to prohibit spurious closure.

(2) Safety Objective:

To assure that all plants with loop isolation valves have power removed during operation, or that other acceptable measures are taken to preclude inadvertent closing.

(3) Status:

In most cases power has been removed from loop isolation valves, and this is confirmed as part of staff ECCS performance evaluations. This has not been confirmed for all plants with loop isolation valves.

TOPIC: VI-7.D Long-Term Cooling Passive Failures (for example, Flooding of Redundant Components)

(1) Definition:

The General Design Criteria require that the emergency core cooling systems (ECCSs) shall be capable of providing adequate core cooling following a loss-of-coolant accident, assuming a single failure in emergency core cooling systems. The staff assumes the single failure to be either an active failure during the injection phase, or an active or passive failure during the long-term recirculation phase. The physical layouts of engineered safety feature pumps and components on some pressurized water reactors make them vulnerable to flooding that might result from passive failures in system piping. Protection for pipe cracks or ruptures is not required because of the low probability of occurrence during the ECCS recirculation mode.

(2) Safety Objective:

To provide for increased reliability of ECCSs by assuring that passive failures will not cause flooding and failure of ECCS valves and equipment.

(3) Status:

Issue identified by Fluegge in letter to Rowden, October 24, 1976. Staff response was prepared which concluded that "...consideration of this issue does not warrant revisions to any existing licenses or changes in present priority for addressing the treatment of passive failures subsequent to a LOCA. ECCS passive failure criteria being implemented by the staff require considerations of additional leakage but not pipe breaks beyond the initiating LOCA."

(4) Reference:

NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 7, "Passive Failures Following a Loss-of-Coolant Accident," December 1976

TOPIC: VI-7.E Emergency Core Cooling System Sump Design and Test for Recirculation Mode Effectiveness

(1) Definition:

Following a loss-of-coolant accident in a PWR, an emergency core cooling system (ECCS) automatically injects water into the system to maintain core cooling. Initially, water is drawn from a large supply tank. Water discharging from the break and containment spray collects in the containment building sump. When the supply tank has emptied to a predetermined level, the ECCS is switched from the "injection" mode to the "recirculation" mode. Water is then drawn from the containment building sump.

ECCSs are required to operate indefinitely in this mode to provide decay heat removal. Certain flow conditions could occur in the sump, which could cause pump failures. These include entrained air, prerotation or vortexing, and losses leading to deficient net positive suction head.

(2) Safety Objective:

To confirm effective operation of ECCSs in the recirculation mode.

(3) Status:

Confirmation through preoperational testing is now required on all construction permits. Staff has been accepting scaled tests in lieu of preoperational tests at the operating-license stage. Some plants have required modification to achieve vortex control.

(4) Reference:

Regulatory Guide 1.79, "Preoperational Testing of Emergency Core Cooling Systems for Pressurized Water Reactors," (paragraph b(2))

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-43, "Containment Emergency Sump Reliability" (NUREG-0510 and NUREG-0660)

  The definition of this topic and the references cited are covered by USI A-43. The evaluation for USI A-43 is identical to SEP Topic VI-7E; therefore, this SEP topic has been deleted.

TOPIC: VI-7.F Accumulator Isolation Valves Power and Control System Design

(1) Definition:

For many loss-of-coolant accidents, the performance of the ECCS in PWR plants depends upon the proper functioning of the accumulators. The motor-operated isolation valve, provided between the accumulator and the primary system, must be considered to be "operating bypass" (IEEE 279-1971) because, when closed, it prevents the accumulator from performing the intended protective function. The motor-operated isolation valve should be designed against a single failure that can result in a loss of capability to perform a safety function.

(2) Safety Objective:

To assure that the accumulator isolation valve meets the "operation bypass" requirements of IEEE 279-1971, which states that the bypass of a protective function will be removed automatically whenever permissive conditions are not met. To assure that a single failure in the electrical system or single operator error cannot result in the loss of capability of an accumulator to perform its safety function.

(3) Status:

Staff positions listed below are implemented on new applications. No systematic review program for operating reactors exists.

(4) References:

1. Institute of Electrical and Electronics Engineers, IEEE Std. 279-1971, "Criteria for Protection System for Nuclear Power Generating Stations"
2. Standard Review Plan, Branch Technical Position EICSB-4, "Requirements on Motor-Operated Valves in the ECCS Accumulator Lines"
3. Standard Review Plan, Branch Technical Position EICSB-18, "Application of Single Failure Criteria to Manually-Controlled Electrically Operated Valves"

TOPIC: VI-8 Control Room Habitability

(1) Definition:

Control rooms in operating plants may not fully comply with General Design Criterion 19. This review should include, but not be limited to, analysis of the control room air infiltration rate, ventilation system isolability and filter efficiency, shielding, emergency breathing apparatus, short distance atmospheric dispersion, operator radiation exposure, and onsite toxic gas storage proximity.

(2) Safety Objective:

To assure that the plant operators can safely remain in the control room to manipulate the plant controls after an accident.

(3) Status:

The Division of Operating Reactors now reviews control room habitability in operating plants when related licensing actions (for example, assessment of BWR containment air dilution system post-LOCA radiological impact) require it. The Division of Site Safety and Environmental Analysis has a technical assistance contract with the National Bureau of Standards to measure the control room air infiltration rate at a few operating plants. These measurements will be used to gauge the conservatism of the assumed air infiltration rates currently used by NRC. Some reviews are now in progress for plants we have reason to believe do not meet General Design Criterion 19 (San Onofre Nuclear Generating Station Unit 1, Vermont Yankee, St. Lucie).

(4) References:

1. Standard Review Plan, Section 6.4
2. 10 CFR Part 50, Appendix A, GDC 19
3. Murphy, K. G., and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Criterion 19," in Proceedings of the Thirteenth AEC Air Cleaning Conference, August 1974
4. Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of a Nuclear Power Plant Control Room During a Postulated Hazardous Chemical Release"
5. Regulatory Guide 1.95, Rev. 1, "Protection of Nuclear Power Plant Control Room Operators Against an Accidental Chlorine Release"

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- TMI Action Plan Task III.D.3.4, "Control Room Habitability Requirements" (NUREG-0737)

  The review criteria required by Task III.D.3.4 (NUREG-0737, pp. 3-197) are identical to the review criteria specified in the Definition and References of SEP Topic VI-8; therefore, this SEP topic has been deleted.

TOPIC: VI-9 Main Steam Line Isolation Seal System (BWR)

(1) Definition:

Operating experience has indicated that there is a relatively high failure rate and variety of failure modes for components of the main steam isolation valve leakage control system in certain operating BWRs.

(2) Safety Objective:

To assure that leakage rate limits are not exceeded and the resulting calculated offsite doses do not exceed 10 CFR Part 100 guidelines using the staff's assumptions.

(3) Status:

Experience from surveillance testing as reported in recent licensee event reports is compiled by the Division of Operating Reactors to serve as a basis for identifying design improvements and for preparing recommendations for future revisions to Regulatory Guide 1.96.

(4) References:

1. Division of Operating Reactors, DOR Technical Activities, Category B, "Main Steam Line Leakage Control System," May 1977
2. Regulatory Guide 1.96, "Design of Main Steam Isolation Valve Leakage Control Systems for Boiling Water Reactor Nuclear Power Plants"
3. Standard Review Plan, Section 6.7

TOPIC: VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response-Time Testing

(1) Definition:

Review the reactor trip system (RTS) and engineered safety features (ESF) test program to verify RTS and ESF operability on a periodic basis and to verify RTS and ESF response time.

(2) Safety Objective:

To assure the operability of the RTS and ESF, on a periodic basis, including verification of sensor response times. To ensure that the RTS and ESF test program demonstrates a high degree of availability of the systems and the response times assumed in the accident analyses are within the design specifications.

(3) Status:

The test program of the RTS and ESF of new license applications is reviewed in accordance with the Standard Review Plan, including applicable Branch Technical Positions. Some licensees have agreed to perform response-time measurements. Operability testing is probably performed, in one form or another, for most licensees of operating reactors.

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB-24, "Testing of Reactor Trip System and Engineered Safety Feature Actuation System Sensor Response Times"
2. Memorandum from V. Stello, NRC, to V. A. Moore, Subject: "GESSAR Second Round of Questions No. 2 and No. 9," October 12, 1973
3. Regulatory Guides
   1.22, "Periodic Testing of Protection System Actuation Functions"
   1.105, "Instrument Setpoints"
   1.118, "Periodic Testing of Electric Power and Protection Systems"

TOPIC: VI-10.B Shared Engineered Safety Features, Onsite Emergency Power, and Service Systems for Multiple Unit Stations

(1) Definition:

The sharing of engineered safety features (ESF) systems, including onsite emergency power systems, and service systems for a multiple-unit facility can result in a reduction of the number and of the capacity of onsite systems to below that which normally is provided for the same number of units located at separate sites. Review these shared systems for multiple-unit stations.

(2) Safety Objective:

To assure that: (1) the interconnection of ESF, onsite emergency power, and service systems between different units is not such that a failure, maintenance, or testing operation in one unit will affect the accomplishment of the protection function of the systems(s) in other units; (2) the required coordination between unit operators can cope with an incident in one unit and safe shutdown of the remaining units(s); and (3) system overload conditions will not arise as a consequence of an accident in one unit coincident with a spurious accident signal or any other single failure in another unit.

(3) Status:

A systematic review of shared ESF, onsite emergency power, and service systems for operating multiple-unit stations is not being conducted. The EICSB Branch Technical Position is applied in the review of new licensee applications.

(4) References:

1. Standard Review Plan, Branch Technical Position EICSB-7, "Shared Onsite Emergency Electric Power Systems for Multi-Unit Stations"
2. Regulatory Guide 1.81, "Shared Emergency and Shutdown Electric Systems for Multi-Unit Nuclear Power Plants"

TOPIC: VII-1.A Isolation of Reactor Protection System From Nonsafety Systems, Including Qualification of Isolation Devices

(1) Definition:

Nonsafety systems generally receive control signals from the reactor protection system (RPS) sensor current loops. The nonsafety sensor circuits are required to have isolation devices to ensure the independence of the RPS channels. Requirements for the design and qualification of isolation devices are quite specific. Recent operating experience has shown that some of the earlier isolation devices or arrangements at operating plants may not be effective.

(2) Safety Objective:

To verify that operating reactors have RPS designs which provide effective and qualified isolation of nonsafety systems from safety systems to assure that safety systems will function as required.

(3) Status:

A limited generic review of isolation devices is being performed by the Division of Operating Reactors as part of a followup on LER No. 76-42/IT for Calvert Cliffs Unit 1 (TAC 6696). This limited generic review should be complete by August 1, 1977.

(4) References:

1. Licensee Event Report No. 76-42/IT, Calvert Cliffs Unit 1 (Technical Assignment Control (TAC) No. 6696)
2. Standard Review Plan, Section 7.2

TOPIC: VII-1.B Trip Uncertainty and Setpoint Analysis Review of Operating Data Base

(1) Definition:

As a result of Issue No. 13 in NUREG-0138 (Ref. 1) the staff is conducting a survey of plants at the operating-license stage of review to more specifically identify the margin between actual allowable trip parameter limits (from safety analyses standpoint) and actual reactor protection system (RPS) setpoints specified in the Technical Specifications. To clearly identify the setpoint margins, both the ultimate allowable and the specified nominal setting will be identified in the Technical Specifications.

(2) Safety Objective:

To assure that the margins between the allowable trip parameters and the actual RPS setpoints are adequate and properly identified.

(3) Status:

Implementation letters have been sent to the current applicants for operating licenses. The Technical Specifications for operating reactors are only being changed to include both values if a particular plant is converting to Standard Technical Specifications.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 13, "Instrument Trip Setpoints in Standard Technical Specifications," November 1976
2. Memorandum from V. Stello, NRC, to R. Boyd, Subject: "Instrument Trip Setpoint Values," February 18, 1977

3. Division of Operating Reactors, DOR Technical Activities, Category B, Item 29, "Instrument Trip Setpoints on Standard Technical Specifications," May 1977

TOPIC: VII-2 Engineered Safety Features System Control Logic and Design

(1) Definition:

During the staff review of the safety injection system (SIS) reset issue (Ref. 1) the staff determined that the engineered safety features actuation systems (ESFASs) at both PWRs and BWRs may have design features that raise questions about the independence of redundant channels, the interaction of reset features and individual equipment controls, and the interaction of the ESFAS logic that controls transfers between onsite and offsite power sources. Review the as-built logic diagrams and schematics, operator action required to supplement the ESFAS automatic actions, the startup and surveillance testing procedures for demonstrating ESFAS performance.

Several specific concerns exist with regard to the manual SIS reset feature following a LOCA: (1) If a loss of offsite power occurs after reset, operator action would be required to remove normal shutdown cooling loads from the emergency bus and reestablish emergency cooling loads. Time would be critical if the loss of offsite power occurred within a few minutes following a LOCA. (2) If loss of offsite power occurs after reset, some plants may not restart some essential loads such as diesel cooling water. (3) The plant may suffer a loss of ECCS delivery for some time period before emergency power picks up the ECCS system.

Review the ESF system control logic and design, including bypasses, reset features, and interactions with transfers between onsite and offsite power sources.

(2) Safety Objective:

To assure that the ESFASs are designed and installed so that the necessary automatic control of engineered safety features equipment can be accomplished when required.

(3) Status:

A review of ESFASs of operating PWRs is being performed by the Division of Operating Reactors as part of the followup action to Reference 1 (to be completed end of 1977).

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 4, "Loss of Offsite Power Subsequent to Manual Safety Injection Reset Following a LOCA," November 1976
2. Division of Operating Reactors, DOR Technical Activities Category A, Item 22, "Loss of Offsite Power Subsequent to Manual Reset," April 1972

3. Regulatory Guide 1.41, "Preoperational Testing of Redundant Onsite Electric Power Systems To Verify Proper Load Group Assignments"

TOPIC: VII-3 Systems Required for Safe Shutdown

(1) Definition:

Review plant systems that are needed to achieve and maintain a safe shutdown condition of the plant, including the capability for prompt hot shutdown of the reactor from outside the control room. Included also, a review of the design capability and method of bringing a PWR from a high-pressure condition to low-pressure cooling assuming the use of only safety-grade equipment.

(2) Safety Objective:

(1) To assure the design adequacy of the safe shutdown system to (i) initiate automatically the operation of appropriate systems, including the reactivity control systems, such that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences or postulated accidents and (ii) initiate the operation of systems and components required to bring the plant to a safe shutdown.

(2) To assure that the required systems and equipment, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown are located at appropriate locations outside the control room and have a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

(3) To assure that only safety-grade equipment is required for a PWR plant to bring the reactor coolant system from a high-pressure condition to a low-pressure cooling condition.

(3) Status:

A survey of remote shutdown capability of operating plants was performed some time ago by the Division of Operating Reactors. A technical activity has been proposed by the Division of Project Management (see reference below) regarding safety objective (3). No other activities are in progress.

(4) Reference:

Division of Project Management, DPM Technical Activities, Category A, Item 7, "Isolating Low Pressure Systems Connected to the RCPB," April 1977

TOPIC: VII-4 Effects of Failure in Nonsafety-Related Systems on Selected Engineered Safety Features

(1) Definition:

Potential combinations of transients and accidents with failures of nonsafety-related control systems were not specifically evaluated in the original safety analysis of currently operating reactor plants. Review the effects of control system malfunctions as initiating events for anticipated transients and also as failures concurrent with or subsequent to anticipated events or postulated accidents initiated by a different malfunction (for example, the effect of the loss of the plant air system on the plant control and monitoring system). A complete discussion is provided in Reference 1.

(2) Safety Objective:

To assure that any credible combination of a nonsafety-related system failure with a postulated transient or accident will not cause unacceptable consequences.

(3) Status:

A technical assistance contract with Oak Ridge National Laboratory for failure mode analyses of control systems was initiated to determine sensitive areas of the plant designs. The results of this program in conjunction with the results of the failure mode and effects analyses for transients and accidents being performed under contract by Idaho Nuclear Engineering Laboratory should provide a basis for any new review and safety requirements.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," Issue 22, "Systematic Review of Normal Plant Operation and Control System Failures," December 1976
2. Memorandum from V. Stello, NRC, to R. J. Hart, December 23, 1976, NRR letter No. 46.
3. Division of Operating Reactors, DOR Task Force Report on SEP, Appendix B (TFL 118), November 1976
   a. Item 33, "Safety Related Control Power"
   b. Item 34, "Safety Related Instrumentation Power"
   c. Item 56, "Effect of Failure in Non-Safety Related Systems During Design Basis Events"
   d. Item 57, "Loss of Plant Air System (Effect on Plant Control and Monitoring)"
   e. Item 77, "Safety Related Control and Instrument Power"
4. Directorate of Operational Technology, DOT Recommended List of SEP Subjects, C DOT 102, Item 100z, "Loss of Plant Air System (Effect on Plant Control and Monitoring)," Spring 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-47, "Safety Implications of Control System" (NUREG-0705 and NUREG-0606)

The issue defined in Reference 1 (NUREG-0153, Item 22) is as follows:

> In evaluating plant safety, the effects of control system malfunctions should be reviewed as initiating events for

anticipated transients and also as failures that could occur concurrently subsequent to postulated anticipated events (initiated by a different malfunction) or postulated accidents.

The issue defined in USI A-47 is, in part, as follows:

> This issue concerns the potential for transients or accidents being made more severe as a result of the failure or malfunction of control systems. These failures or malfunctions may occur independently, or as a result of the accident or transient under consideration.

(b) <u>USI A-17, "Systems Interactions in Nuclear Power Plants" (NUREG-0649 and NUREG-0606)</u>

The purpose of this task is to develop a method for conducting a disciplined and systematic review of nuclear power plant systems, for both process function couplings of systems and space couplings, to identify the potential sources and types of systems interactions that are determined to be potentially adverse.

A report has been developed, "Final Report - Phase 1 Systems Interaction Methodology Applications Program," NUREG/CR-1321, SAND 80-0384, whose objectives are:

1. To develop a methodology for conducting a disciplined and systematic review of nuclear power plant systems which facilitates identification and evaluation of systems interactions that affect the likelihood of core damage.

2. To use the methodology to assess the Standard Review Plan to determine the completeness of the plan in identifying and evaluating a limited range of systems interactions.

The work done under USI A-17 may be useful in the development of USI A-47.

The Definition of USI A-47 is identical to that of Topic VII-4; therefore, this SEP topic has been deleted.

<u>TOPIC</u>: VII-5 Instruments for Monitoring Radiation and Process Variables During Accidents

(1) <u>Definition</u>:

The adequacy of the instruments for monitoring radiation and process variables during accidents has not been reviewed for conformance with Regulatory Guide 1.97. A generic review is planned to assess the licensee's existing or proposed monitoring instruments during and following accidents to determine the adequacy of tneir range, response, and qualifications, and to determine the sufficiency of the variables to be monitored. Certain instruments to monitor conditions beyond the design basis accidents will also be required in accordance with an Regulatory Requirements Review Committee (RRRC) determination (Reference 3).

(2) Safety Objective:

To assure that plant operators and emergency response personnel have available sufficient information on plant conditions and radiological releases to determine appropriate in-plant and offsite actions throughout the course of any accident. The instrumentation should also provide recorded transient or trend information necessary for postaccident evaluation of the event. The ability to follow the course of accidents beyond the design basis accidents is also required.

(3) Status:

Generic review of instrumentation to follow the course of accidents in operating plants and in all plants now under construction or seeking a construction permit will begin with the issuance of Regulatory Guide 1.97, Revision 1, this year. Submittals describing the facilities' postaccident instrumentation will be obtained from all operating licensees and reviewed by the end of 1978. The implementation of Regulatory Guide 1.97, Revision 1 on operating plants is proceeding independent of the SEP. The Regulatory Requirements Review Committee has determined that Revision 1 to Regulatory Guide 1.97 should be treated as a Category 2 item (backfit on operating plants on a case-by-case basis).

(4) References:

1. Memorandum from H. G. Mangelsdorf (ACRS) to L. M. Muntzing (Regulations), August 14, 1973
2. Memorandum from L. M. Muntzing (Regulation) to H. G. Mangelsdorf (ACRS), November 1, 1973
3. Memorandum from R. B. Minogue (SD) to E. G. Case (NRR), Enclosure, Proposed Revision 1 to Regulatory Guide 1.97, April 4, 1977
4. Standard Review Plan, Section 7.5
5. Standard Review Plan, Section 7.6
6. Standard Review Plan, Section 11.5
7. Memorandum from T. A. Ippolito (EICSB) to Emergency Instrumentation Task Force Members, August 12, 1974
8. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR Staff," Issue 21, "Instruments for Monitoring Both Radiation and Process Variable During Accidents," December 1976
9. Minutes of Regulatory Requirements Review Committee meeting, January 28, 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- TMI Action Plan Task II.F, "Instrumentation and Controls" NUREG-0660 and NUREG-0737

There are three subtasks under Task II.F as follows:

(a) II.F.1 - Additional Accident Monitoring Instrumentation

(b) II.F.2 - Identification of and Recovery From Conditions Leading to Inadequate Core Cooling

(c) II.F.3 - Instruments for Monitoring Accident Conditions

Specific positions on the required instrumentation for II.F.1 and II.F.2 are in NUREG-0737 and Regulatory Guide 1.97, Revision 2 (December 1980). Instrumentation need for II.F.3 is also in Regulatory Guide 1.97, Revision 2.

The emphasis of TMI Task II.F is the monitoring of radiation and process variables; guidance for this relies primarily on Regulatory Guide 1.97. This is identical to the review proposed in Topic VII-5; therefore this SEP topic has been deleted.

TOPIC: VII-6 Frequency Decay

(1) Definition:

In an issue of Reference 1 it is stated that the staff should require that a postulated rapid decay of the frequency of the offsite power system be included in the accident analysis and that the result be demonstrated to be acceptable. Alternatively, the reactor coolant pump (RCP) circuit breakers should be designed to protection system criteria and tripped to separate the pump motors from the offsite power system. Rapid decay of the frequency of the offsite power system has the potential for slowing down or breaking the RCP, thereby reducing the coolant flow rates to levels not considered in previous analyses.

(2) Safety Objective:

To assure that the reactor coolant flow rate will not decrease below those assumed for a flywheel coastdown.

(3) Status:

Oak Ridge National Laboratory, under a technical assistance program, is currently reviewing the frequency decay rate and its effects on RCPs. This program should be completed before the end of this year and this issue resolved.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 9, "Frequency Decay," November 1976
2. Division of Operating Reactors, DOR Technical Activities, Category B, Item 27, "Frequency Decay," May 1977

TOPIC: VII-7 Acceptability of Swing Bus Design on BWR-4 Plants

(1) Definition:

The swing bus in the original BWR-4 design was used to provide power from either of two redundant electric sources to the low-pressure coolant injection (LPCI) valves by means of an automatic transfer scheme. A single failure in the transfer circuitry could result in paralleling the two redundant electric power sources, thereby degrading their functional capabilities. Review licensee's swing bus automatic transfer circuitry to verify that it is immune to single failures which could lead to paralleling the two electric power sources.

(2) Safety Objective:

To assure that the swing bus design will not propagate an electrical failure between two redundant power sources due to a single failure in the automatic transfer circuit at the BWR-4 swing bus.

(3) Status:

During the course of generic review for compliance with emergency core cooling system criteria 10 CFR 50.46 and Appendix K, some licensees have elected to modify the LPCI system to take credit for a portion of the LPCI flow. These facilities have replaced the swing bus design with a split bus configuration which complies with the requirements of Regulatory Guide 1.6. Not all facilities required a modification of the LPCI to meet the criteria and have retained the swing bus design.

The issue of the swing bus design was identified in Reference 1 and in addition in a letter from the Advisory Committee on Reactor Safeguards (ACRS) dated December 12, 1976.

(4) References:

1. NUREG-0138, "Staff Discussion of Fifteen Technical Issues Listed in Attachment to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue No. 3, "Acceptability of Swing Bus Design of BWR-4 Plants," November 1976
2. Regulatory Guide 1.6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems"
3. 10 CFR Part 50, Appendix A, GDC 17
4. Institute of Electrical and Electronics Engineers, IEEE Std. 308, "Standard Criteria for Class IE Electric Systems for Nuclear Power Generating Stations"

TOPIC: VIII-1.A Potential Equipment Failures Associated With Degraded Grid Voltage

(1) Definition:

A sustained degradation of the offsite power source voltage could result in the loss of capability of redundant safety loads, their control circuitry, and the associated electrical components required to perform safety functions.

(2) Safety Objective:

To assure that a degradation of the offsite power system will not result in the loss of capability of redundant safety-related equipment and to determine the susceptibility of such equipment to the interaction of onsite and offsite emergency power sources.

(3) Status:

A program plan has been developed which includes a short-term program for the review of the emergency power systems of operating reactors and a long-term program to identify those conditions affecting the offsite power sources which may require that additional safety measures be taken.

(4) References:

1. NUREG-0090-5, "Report to Congress, Abnormal Occurrences at Millstone 2, July-September 1976," March 1977
2. Memorandum from D. G. Eisenhut, NRC, to K. R. Goller, Subject: "Staff Positions (Short-Term Program)," April 20, 1977
3. Letters to licensees, August 12 and 13, 1976
4. Division of Operating Reactors, DOR Technical Activities, Category A, Item 9, "Potential Equipment Failures Associated with a Degraded Off-site Power Source," April 1977

TOPIC: VIII-2 Onsite Emergency Power Systems (Diesel Generator)

(1) Definition:

Diesel generators, which provide emergency standby power for safe reactor shutdown in the event of total loss of offsite power, have experienced a significant number of failures. The failures to date have been attributed to a variety of causes, including failure of the air startup, fuel oil, and combustion air systems. In some instances, the malfunctions were due to lockout. The information available to the control room operator to indicate the operational status of the diesel generator was imprecise and could lead to misinterpretation. This was caused by the sharing of a single annunciator station by alarms that indicate conditions that render a diesel generator unable to respond to an automatic emergency start signal and alarms that only indicate a warning of abnormal, but not disabling, conditions. Another cause was the wording on an annunciator window which did not specifically say that the diesel generator was inoperable (that is, unable at the time to respond to an automatic emergency start signal), when in fact it was inoperable for that purpose. The review includes the qualification, reliability, operation at low loads, lockout, fuel oil, and testing of diesel generators.

(2) Safety Objective:

To assure that the diesel generator meets the availability requirements for providing emergency standby power to the engineered safety features.

(3) Status:

Under a technical assistance request (in preparation), a thorough evaluation of all reported failures, including a comprehensive evaluation of diesel manufacturer and utility procedures for inspection, maintenance, and operation, will be performed. Letters were sent on March 29, 1977 to all the affected licensees requesting additional information about diesel generator status indication in the control room. Our intention is to require that at least one annunciation be provided in the control room which will alarm whenever the diesel generator is unavailable due to any lockout condition.

(4) References:

1. Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants"
2. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-11, "Diesel Generator Lockout," April 1977

TOPIC: VIII-3.A Station Battery Capacity Test Requirements

(1) Definition:

Review the Technical Specification, including the test program, with regard to the requirement for periodic surveillance testing of onsite Class IE batteries and the extent to which the test meets Section 5.3.6 of IEEE Std. 308-1971, to determine battery capacity.

(2) Safety Objective:

To assure that the onsite Class IE battery capacity is adequate to supply dc power to all safety-related loads required by the accident analyses and is verified on a periodic basis. This effort is needed to ensure that the test to determine battery capacity includes (1) an acceptance test of battery capacity performed in accordance with Section 4.1 of IEEE Std. 450-1975; (2) a performance discharge test listed in Table 2 of IEEE Std. 308-1971, performed according to Sections 4.2 and 5.4 of IEEE Std. 450-1975; and (3) a battery service test described in Section 5.6 of IEEE Std. 450-1972, to be performed during each refueling operation.

(3) Status:

The review of station battery capacity test requirements is applicable to all operating reactors. There is no ongoing effort on this subject for operating reactors except for those reactors converting to Standard Technical Specifications.

(4) References:

1. Standard Review Plan, Appendix 7-A, Branch Technical Position EICSB 6
2. Institute of Electrical and Electronics Engineers, IEEE Std. 308-1971, 1974, "Standard Criteria for Class 1E Electric Systems for Nuclear Power Generating Stations"

3. Institute of Electrical and Electronics Engineers, IEEE Std. 450-1975, "Recommanded Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations"
4. Memorandum from J. G. Keppler to R. H. Vollmer, NRC, March 20, 1972
5. Memorandum from V. D. Thomas to R. Carlson, January 18, 1972

TOPIC: VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

(1) Definition:

Review the dc power system battery, battery charger, and bus voltage monitoring and annunciation design with respect to dc power system operability status indication to the operator. This information is needed so that timely corrective measures can be taken in the event of loss of an emergency dc bus.

(2) Safety Objective:

To assure the design adequacy of the dc power system battery and bus voltage monitoring and annunciation schemes such that the operator can (1) prevent the loss of an emergency dc bus or (2) take timely corrective action in the event of loss of an emergency dc bus.

(3) Status:

The review of the dc power system battery and bus voltage monitoring and annunciation adequacy as it relates to the loss of an emergency dc bus is applicable to all operating reactors. This topic is included in the NRR Technical Activity, "Adequacy of Safety Related DC Power Supplies."

(4) Reference:

Standard Review Plan, Section 8.3.2

TOPIC: VIII-4 Electrical Penetrations of Reactor Containment

(1) Definition:

Review the electrical penetration assembly with respect to the capability to maintain containment integrity during short-circuit current conditions and mechanical integrity during the worst expected fault current vs. time conditions resulting from single random failures of circuit overload protection devices.

(2) Safety Objective:

To assure that all electrical penetrations in the containment structure, whether associated with Class IE circuits or non-Class IE circuits, are designed not to fail from electrical faults during a loss-of-coolant accident.

(3) Status:

The subject of electrical cable penetrations was identified in Reference 1 and has been proposed as a Technical Activity Category A item by the Division of Systems Safety (Reference 2). The purpose of that activity is a reevaluation of the penetrations to clarify and augment the design safety margin.

(4) References:

1. NUREG-0153, "Staff Discussion of Twelve Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum From Director, NRR, to NRR Staff," Issue 18, "Electrical Cable Penetration of Reactor Containment," December 1976
2. Division of Systems Safety, DSS Technical Activity, Category A, Item 36, "Electrical Cable Penetrations of Reactor Containment," April 1977
3. Regulatory Guide 1.63, "Electric Pentration Assemblies in Containment Structures for Light-Water-Cooled Nuclear Power Plants"
4. Institute of Electrical and Electronics Engineers, IEEE Std. 317-1976, "Standard for Electric Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations"

TOPIC: IX-1 Fuel Storage

(1) Definition

Review the storage facility for new and irradiated fuel, including the cooling capability and seismic classification of the fuel pool cooling system of the spent fuel storage pool. Specifically review the expansion of the onsite spent fuel storage capacity, including the structural response of the fuel storage pool and the racks, the criticality analysis for the increased number of stored fuel assemblies at reduced spacing, and the capability of the spent fuel cooling system to remove the additional heat load.

(2) Safety Objective:

To assure that new and irradiated fuel is stored safely with respect to criticality ($k_{eff} < 0.95$), cooling capability (outlet temperature $< 150^\circ F$), shielding, and structural capability.

(3) Status:

Approximately two-thirds of the operating reactor plants have requested authorization to increase the storage capacity of their fuel storage pool. The applications are reviewed on a case-by-case basis. New or modified storage rack designs are reviewed against current design criteria; however, the existing pool structure is based on original design criteria.

(4) References

1. Division of Operating Reactors, DOR Technical Activities, Category A, Item 27, "Increase in Spent Fuel Storage Capacity," April 1977
2. American National Standards Institute, ANSI-210, "Design Objectives for Spent Fuel Storage Facilities"

TOPIC: IX-2 Overhead Handling Systems (Cranes)

(1) Definition:

Overhead handling systems (cranes) are used to lift heavy objects in the vicinity of PWR and BWR spent fuel storage facilities and inside the reactor building. If a heavy object (for example, a shielded cask) were to drop on the spent fuel or on the reactor core during refueling, there could be a potential for overexposure of plant personnel and for release of radioactivity to the environment. Review the overhead handling system, including sling and other lifting devices, and the potential for the drop of a heavy object on spent fuel, including structural effects.

(2) Safety Objective:

To assess the safety margins, and improve margins where necessary, of the overhead handling systems to assure that the potential for dropping a heavy object on spent fuel is within acceptable limits and that the potential radiation dose to an individual does not exceed the guidelines of 10 CFR Part 100.

(3) Status:

Regulatory Guide 1.104, "Overhead Crane Handling Systems for Nuclear Power Plants," was issued for comment in February 1976 and references various industry standards. New applications (construction permit and operating license) are reviewed in accordance with APCSB Branch Technical Position 9-1 which is identical to Regulatory Guide 1.104.

The review of overhead handling systems of operating reactor facilities is performed on a generic basis and has also been identified as a DOR Technical Activity Category A.

(4) References:

1. Regulatory Guide 1.104, "Overhead Crane Handling Systems for Nuclear Power Plants"
2. Standard Review Plan, Branch Technical Position APCSB 9-1, "Overhead Handling Systems for Nuclear Power Plants"
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-22, "Fuel Cask Drop Analysis," April 1977
4. Division of Operating Reactors, DOR Technical Activities, Category A, Item 50, "Control of Heavy Loads Over Spent Fuel," April 1977

(5) Basis for Deletion (Related TMI Task, USI or Other SEP Topic):

- USI A-36, "Control of Heavy Loads Near Spent Fuel" (NUREG-0649)

  The review criteria required by USI A-36 (Standard Review Plan, Section 9.1.4, and NUREG-0554) are identical to the review criteria specified in the References of SEP Topic IX-2 (BTP 9-1 and Regulatory Guide 1.104); therefore, this SEP topic has been deleted.

TOPIC: IX-3 Station Service and Cooling Water Systems

(1) Definition:

Review the station service water and cooling water systems that are required for safe shutdown during normal, operational transient, and accident conditions, and for mitigating the consequences of an accident or preventing the occurence of an accident. These include cooling water systems for reactor system components (components cooling water system), reactor shutdown equipment, ventilation equipment, and components of the emergency core cooling system (ECCS). These systems also include the station service water system, the ultimate heat sink, and the interaction of all the above systems.

The review of these systems includes the pumps, heat exchangers, valves and piping, expansion tanks, makeup piping, and points of connection or interfaces with other systems. Emphasis is placed on the cooling systems for safety-related components such as ECCS equipment, ventilation equipment, and reactor shutdown equipment.

The following specific aspects of those systems will be considered in the review:

(a) Physical separation of redundant cooling water systems that are vital to the performance of engineered safety systems components,

(b) Availability of cooling water to primary reactor coolant pumps,

(c) Requirements for makeup water of cooling water systems,

(d) Effect of water overflow from tanks,

(e) Circulating water system barrier failure protection.

(2) Safety Objective:

To assure that the station service and cooling water systems have the capability, with adequate margin, to meet their design objective. To assure, in particular, that

(a) Systems are provided with adequate physical separation such that there are no adverse interactions among those systems under any mode of operation;

(b) Cooling water is provided to the bearings of the primary reactor coolant pumps by two independent essential service water systems for PWR plants to take credit for core cooling by pump coastdown. In addition, it should be demonstrated that the possibility of simultaneous loss of water in both essential service water systems by valve closure is sufficiently small;

(c) Sufficient cooling water inventory has been provided or that adequate provisions for makeup are available;

(d) Tank overflow cannot be released to the environment without monitoring and unless the level of radioactivity is within acceptable limits;

(e) Vital equipment necessary for achieving a controlled and safe shutdown is not flooded due to the failure of the main condenser circulating water system.

(3) Status:

The station service and cooling water systems of applications currently under review are evaluated in accordance with the Standard Review Plan (Sections 9.2.2 and 10.4.5). Some of the specific concerns identified above are under generic review or have been proposed for a technical activity in the Office of Nuclear Reactor Regulation in accordance with the references below.

(4) References:

1. Letter from R. F. Fraley (ACRS) to L. V. Gossick, Subject: "Analysis of Systems Interactions," November 1, 1976
2. Memorandum from B. C. Rusche to L. V. Gossick, ACRS Subcommittee on Systems Interactions, January 1977
3. Division of Project Management, DPM Technical Activities, Category A, Item DPM-15, "Systems Interactions in Nuclear Power Plants," April 1977
4. Memorandum to R. L. Tedesco, NRC, to D. B. Vassallo, Auxiliary Systems Branch 02 on Yellow Creek Nuclear Plant, Item 010.42, (cooling water for RCP), January 31, 1977
5. Division of Systems Safety, DSS Technical Safety Activities Report, "Cooling Water System Makeup Water Requirements (For Safety Systems)," December 1975
6. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-20, "Flood of Equipment Important to Safety (Generic)," April 1977
7. Division of Operating Reactors, DOR Technical Activities, Category A, Item 15, "Flood of Equipment Important to Safety," April 1977

TOPIC: IX-4 Boron Addition System (PWR)

(1) Definition:

Review the boron addition system (PWR), in particular with respect to boron precipitation during the long-term cooling mode of operation following a loss-of-coolant accident.

(2) Safety Objective:

To assure that boron precipitation will not impair the operability of valves or components in the boron addition system which could compromise its capability to control core reactivity during the normal, transient, or emergency shutdown conditions or that would result in flow blockage through the core during the long-term core cooling mode following a loss-of-coolant accident.

(3) Status:

Operating PWR reactors, with the exception of the Combustion Engineering reactors, have been reviewed and found to be acceptable in regard to boron precipitation following a loss of coolant. There are still certain outstanding issues that need to be resolved on this issue for Combustion Engineering reactors. In regard to the precipitation of boron in the boron addition system in both BWRs and PWRs, certain older plants may not have been reviewed in sufficient detail to assure that system reliability is adequate.

(4) Reference:

Standard Review Plan, Section 9.3.4

TOPIC: IX-5 Ventilation Systems

(1) Definition:

Review the design and operation of ventilation systems whose function is to maintain a safe environment for plant personnel and engineered safety features equipment. For example, the function of the spent fuel pool area ventilation system is to provide ventilation in the spent fuel pool equipment areas, to permit personnel access, and to control airborne radioactivity in the area during normal operation, anticipated operational transients, and following postulated fuel handling accidents. The function of the engineered safety feature ventilation system is to provide a suitable and controlled environment for engineered safety feature components following certain anticipated transients and design basis accidents.

(2) Safety Objective:

To assure that the ventilation systems have the capability to provide a safe environment, under all modes of operation, for plant personnel (10 CFR Part 20) and for engineered safety features (for example, to assure that the diesel room has redundant outside air intakes and removed from the exhaust discharge).

(3) Status:

The ventilation systems of plants under current review (construction permit and operating license applications) are currently evaluated in accordance with the Standard Review Plan. No specific issues or concerns have been identified for operating reactor plants.

(4) References:

Standard Review Plan, Sections 9.4.1 through 9.4.5

TOPIC: IX-6 Fire Protection

(1) Definition:

Review the fire protection program of operating reactor plants to determine whether improvements are required in accordance with the APCSB Technical Position 9.5-1, Appendix A (Reference 2). The fire protection program encompasses the components, procedures, and personnel utilized in carrying out all activities of fire protection and includes such things as fire prevention, detection, annunciation, control, confinement, suppression, extinguishment, administrative procedures, fire brigade organization, inspection and maintenance, training, quality assurance, and testing. The review includes such items as: (1) the use of insulation inside the containment and (2) the consequences of the inadvertent release of hydrogen into the plant.

(2) Safety Objective:

To assure that, in case of a fire within the plant, the integrity of the engineered safety features is not compromised and that the safe shutdown capability and control of the plant are not lost.

(3) Status:

A generic review of fire protection for operating plants is under way. All licensees were requested by letter (May 11, 1976) to submit an evaluation of their fire protection program for that plant in comparison with the APCSB Technical Position 9.5-1. Subsequently, in September 1976, the licensees were provided with Appendix A to the BTP 9.5-1 which presents acceptable alternatives for operating plants.

(4) References:

1. NUREG-0050, "Recommendations Related to Browns Ferry Fire," February 1976
2. Standard Review Plan, Branch Technical Position APCSB 9.5-1, Appendix A, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976"

3. Regulatory Guide 1.120, "Fire Protection Guidelines for Nuclear Power Plants"
4. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book), Generic Issue 3-18, "Fire Protection," April 1977
5. Division of Operating Reactors, DOR Technical Activities, Category A, Item 28, "Fire Protection," April 1977
6. Division of Systems Safety, DSS Technical Activities, Category A, Item 32, "Fire Protection," April 1977
7. Letter from R. F. Fraley, ACRS, to L. V. Gossick, Subject: "Analysis of Systems Interactions - Item 6," November 1, 1976

TOPIC: X Auxiliary Feedwater System

(1) Definition:

Review the auxiliary feedwater system, associated instrumentation, and connection between redundant systems. The review includes the aspects of pump drive and power supply diversity (for example, electrical and steam-driven sources), and the water supply sources for the auxiliary feedwater system.

(2) Safety Objective:

To assure that the auxiliary feedwater system can provide an adequate supply of cooling water to the steam generators for decay heat removal in the event of a loss of all main feedwater. Older PWR plants may not meet the requirement for pump drive and power supply diversity.

(3) Status:

Reviews for new license applications are performed in accordance with the Standard Review Plan. This topic is not under active review for operating plants.

(4) References:

1. Standard Review Plan, Section 10.4.9
2. Standard Review Plan, Branch Technical Position APCSB 10-1, "Design Guidelines for Auxiliary Feedwater System Pump Drive and Power Supply Diversity for PWR Plants"

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- TMI Action Plan Task II.E.1.1, "Auxiliary Feedwater System Evaluation" (NUREG-0660)

  The TMI-2 accident and subsequent investigations and studies highlighted the importance of the auxiliary feedwater (AFW) system in the mitigation of severe transients and accidents. Since then, the AFW systems have come under close scrutiny by the NRC and many improvements have been recommended to enhance the reliability of AFW systems for all plants. The scope of the review outlined in the SEP

Topic X definition is identical to the scope of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.E.1.1(2), which requires that each PWR plant licensee:

> Perform a deterministic review of the AFW system using the acceptance criteria of Standard Review Plan Section 10.4.9 and associated Branch Technical Position ASB 10-1 as principal guidance.

The review criteria for the evaluations required by Item II.E.1.1(2) are identical to SEP Topic X; therefore, this SEP topic has been deleted.

TOPIC: XI-1 Appendix I

(1) Definition:

A generic review of all operating plants to determine their capability to comply with Appendix I, 10 CFR 50, and to prevent explosions in the gaseous radwaste system is currently underway.

(2) Safety Objective:

To provide assurance that radioactive gaseous effluents from the facility can be kept "as low as reasonably achievable" as defined in Appendix I, 10 CFR Part 50, and to assure adequate control of the mixture of gases in the gaseous radwaste system to prevent explosions.

(3) Status:

A generic review of all operating reactors (ORs) for their capability to conform with Appendix I, 10 CFR Part 50, is currently under way by the Division of Site Safety and Environmental Analysis. Upon the completion of this review, new gaseous and liquid radiological effluent and monitoring Technical Specifications will be issued to all ORs. This will include new Technical Specifications on gaseous radwaste systems which may contain explosive gas mixtures to meet present criteria. The estimated completion date of this review is 1979.

(4) References:

1. 10 CFR Part 20
2. 10 CFR Part 50, Appendix I
3. 10 CFR Part 50, Appendix A
4. 10 CFR Part 50, Appendix A, GDC 60, 61, 63, and 64
5. Standard Review Plan, Section 11.3

(5) Basis for Deletion

Topic XI-1 is being resolved by the following NRR generic topics: (a) A-02, "Appendix I" and (b) B-35, "Confirmation of Appendix I Models." Resolution of these two generic topics will primarily result in Technical Specification changes and may require some minor hardware changes. At present, nothing more than the addition of monitoring instrumentation is foreseen. The implementation of Appendix I will, therefore, not affect the integrated assessment for SEP plants.

In addition, the implementation of Appendix I will result in limiting conditions for operation to assist licensees in keeping the amount of radioactive material released in effluents to unrestricted areas as low as is reasonably achievable. Since licensees are currently restricted in the types and amounts of effluents they can release, implementation of additional restrictions on releases should not impact operation of the plant.

Based on the above, Topic XI-1 has been deleted from the SEP program.

TOPIC: XI-2 Radiological (Effluent and Process) Monitoring Systems

(1) Definition:

Onsite radiological monitoring systems are used to:

(a) Assess the proper functioning of the process and waste treatment systems,

(b) Assure that radioactive releases do not exceed the appropriate guidelines, and

(c) Measure actual releases to evaluate their environmental impact.

There is concern about the adequacy of radiation monitoring systems. A survey of 12 plants has been initiated. The results of this survey will indicate whether this area needs to be reviewed for all operating plants. Re-review would include the monitor's sensitivity, range, location, and calibration techniques.

(2) Safety Objective:

To provide reasonable assurance that the licensee adequately monitors the releases of radioactive materials in liquid and gaseous effluent and that the releases are properly restricted. To provide assurance that the licensee adequately monitors the operation of equipment that contains or may contain radioactive material.

(3) Status:

A technical assistance program has been initiated at Brookhaven National Laboratory with the scope including the above safety objectives.

(4) References:

1. 10 CFR Part 20, Section 20.106
2. 10 CFR Part 50, Section 50.36a
3. 10 CFR Part 50, Appendix A, GDC 60, 61, 63, and 64
4. 10 CFR Part 50, Appendix I
5. Standard Review Plan, Section 11.5

(5) Basis for Deletion

Topic XI-2 is being resolved by the following NRR generic topics: (a) A-02, "Appendix I" and (b) B-67, "Effluent and Process Monitoring Instrumentation." A-02 is discussed in Topic XI-1. Generic item B-67 was subdivided into four subtasks. The staff believes that events since the inception of B-67 have largely addressed the identified concerns or changed its thinking in regard to their safety significance. The description and bases for deletion of each subtask are presented below.

Subtask 1: Monitoring of Radioactive Materials Released in Effluents

Item III.D.2.1, Radiological Monitoring of Effluents requires an NRR evaluation of modifying effluent monitoring design criteria based on TMI-2 and their experiences.

Item II.F.1(1), Noble Gas Effluent Monitor of Clarification of the TMI Action Plan Requirements (NUREG-0737) is being implemented to require adequate monitoring capability during accident conditions.

Subtask 2: Control of Radioactive Materials Released in Effluents

The purpose of this subtask was to review plant operating histories and prepare NUREG reports documenting the evaluations and recommending solutions to identified problems.

Various staff actions since 1978 (including NUREG reports and IE Bulletins) have resulted in the staff conclusion that no continuing need for additional staff guidance exists.

Subtask 3: Effects of Accidental Liquid Releases on Nearby Water Supplies

The purpose of this task was to perform a generic analysis of the consequences of liquid tank failures for those plants which received their license prior to issuance of the Standard Review Plan (SRP).

Experience in performing SRP analyses for newer plants has indicated that it is highly unlikely that radioactive concentrations in the nearest potable water supply could exceed 10 CFR Part 20 values.

Subtask 4: Performance of Solid Waste Systems

The purpose of subtask 4 was to perform an industry-wide survey to determine the extent to which power plants could process wastes and to develop plans for upgrading existing systems or adding new systems.

The NRC position relative to a requirement for an operable installed solid radwaste system has changed and, therefore, this subtask is no longer appropriate.

For the above reasons, Issue B-67 is being deleted from the NRR list of generic issues. Since Issue B-67 is being deleted, only Generic Issue A-02, "Appendix I" is appropriate to this topic.

The resolution of Issue A-02 is described in the Basis for Deletion for Topic XI-1. Topic XI-2 is being deleted from the SEP program for the same reasons.

TOPIC: XIII-1 Conduct of Operations

(1) Definition:

The organization, administrative controls, and operating experience will be reviewed. The existing organization and administrative controls will be compared with Standard Technical Specifications and guidance provided in Regulatory Guides 1.8 and 1.33 to determine the adequacy of the staff to protect the plant and to operate safely in routine, emergency, and long-term postaccident circumstances. The plant operating history will be reviewed to assess the combination of staff, operating controls and alarms, and administrative controls, in particular plant procedures, emergency planning, and offsite preparedness, to determine whether additional staff, qualifications, or administrative controls will be required for continued safe operation.

(2) Safety Objective:

To obtain reasonable assurance that the plant has enough people, with sufficient training and experience, and has administrative controls adequate to specify proper operation in routine, emergency, and postaccident conditions.

(3) Status:

Most of the older plants have staff members that meet the experience and educational requirements given in ANSI N18.1-1971 (endorsed by Regulatory Guide 1.8); however, a comparison against current criteria for the composite staff has not been made. These plants have provided training for subsequent plant staffs, and plant experience has, in general, demonstrated safe design and operation. Operating experience review is ongoing, and has been, in general, favorable. However, an analysis of this experience for trends, common elements, and potential hidden problems has not been systematically performed.

A review of Section VI of operating reactor licensees' Technical Specifications was begun in 1974 using Section VI of the Standard Technical Specifications (STS) as a model. As of September 1975, these reviews had been completed and the plants licensed prior to this time had been found to: (1) be acceptable and upgrading was not required, (2) require upgrading of only the reporting requirements, or (3) require improvement to be comparable to the STS model. Plants licensed after September 1975 have been reviewed against the STS model. Further review of Section VI, therefore, will not be required.

Emergency plans submitted at the operating-license stage complied with 10 CFR 50, Appendix E, 1970; however, these plans are not consistent with the guidance given in new Regulatory Guide 1.101, Revision 1, 1977.

(4) References:

1. Regulatory Guides
   1.8, "Personnel Selection and Training"
   1.33, "Quality Assurance Program Requirements (Operations)"
2. American National Standards Institute, ANSI N18.1-1971, "Selection and Training of Nuclear Power Plant Personnel"
3. American National Standards Institute, ANSI N18.7-1972 Revised, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants"
4. Standard Technical Specifications, Section VI
5. 10 CFR Part 50, Appendix E
6. Regulatory Guide 1.101, Rev. 1, "Emergency Planning for Nuclear Power Plants"
7. Standard Review Plan, Section 13.3
8. NUREG 75/111, "Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans In Support of Fixed Nuclear Facilities," October 1975
9. Environmental Protection Agency, "EPA Manual of Protective Action Guides and Protective Action for Nuclear Incidents," September 1975
10. Memorandum of Understanding, NRR and Office of State Programs on State and Local Preparedness, March 10, 1977

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) TMI Action Plan Task I.C.6, "Procedures for Verification of Correct Performance of Operating Activities," (NUREG-0737)

Under TMI Task I.C.6, a review of licensee procedures will be conducted to assure that an effective system of verifying the correct performance of operating activities exists. The purpose of this review is to provide a means of reducing human errors and improving the quality of normal operation. References cited for this review are ANSI Standard N18.7-1972 (ANS 3.2), "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)." These are the same references cited for Topic XIII-1.

(b) TMI Action Plan Task III.A.1, "Improve Licensee Emergency Prepared ness - Short-Term," and Task III.A.2, "Improving Licensee Emergency Preparedness - Long-Term" (NUREG-0660 and NUREG-0737)

Under Task III.A.1, a review of 10 CFR Part 50, Appendix E backfit requirements is being conducted in accordance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants." The scope of NUREG-0654 covers Standard Review Plan, Section 13.3, and NUREG 75/111.

Regulatory Guide 1.101 has been deleted and has been superseded by an amended Appendix E to 10 CFR Part 50 (45 FR 55410, August 19, 1980). Under Task III.A.2, a review of licensee's emergency preparedness plans with respect to amended Appendix E will be conducted in accordance with NUREG-0654.

The evaluations required by TMI Tasks I.C.6, III.A.1, and III.A.2 are identical to SEP Topic XIII-1; therefore, this SEP topic has been deleted.

TOPIC: XIII-2 Safeguards/Industrial Security

(1) Definition:

Industrial security will be included under the scope of the operations review. Design features to assess the plant's capability to prevent sabotage and protect the operating unit(s) at dual or three-unit sites with unit(s) under construction will be included. Protective measures will be balanced against the sabotage threat. Fuel accountability will also be reviewed to assure that adequate inventory control procedures exist and the required records are kept.

(2) Safety Objective:

To determine that the plant has adequate security forces, design features, procedures and plans, and other administrative controls to meet the postulated sabotage threat. To assure that the fuel is adequately accounted for, that proper records are maintained, and the required reports are made.

(3) Status:

Each licensee currently has a security program and a fuel accountability program. Revised 10 CFR 73.55 has been published and submittals in accordance with its provisions were due May 25, 1977. These submittals are currently being evaluated.

(4) References:

1. 10 CFR Part 70
2. 10 CFR Part 73
3. Standard Technical Specifications, Section VI

TOPIC: XV-1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of A Steam Generator Relief or Safety Valve

(1) Definition:

Review the assumptions, calculational models used and consequences of postulated accidents which involve an unplanned increase in heat removal. An excessive heat removal, that is, a heat removal rate in excess of the heat generation rate in the core, causes a decrease in moderator temperature which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. If clad failure is calculated to occur, determine that offsite dose consequences are acceptable.

(2) Safety Objective:

To assure that pressures in the reactor coolant and main steam systems are limited in order to protect the reactor coolant pressure boundary from overpressurization and that fuel rod cladding failure as a result of departure from nucleate boiling ratio is limited.

(3) Status:

During each reload review by the staff, the previously determined limiting transient is reviewed to determine if new core parameters are more restrictive than the reference analysis parameter values.

(4) References:

Standard Review Plan, Sections 15.1.1 through 15.1.4

TOPIC: XV-2 Spectrum of Steam System Piping Failures Inside and Outside of Containment (PWR)

(1) Definition:

Review the assumptions, including use of nonsafety-grade equipment and concurrent steam generator or tube failure or blowdown of more than one steam generator, calculational models used, and consequences of postulated accidents which cause an increase in steam flow. The excessive steam flow reduces system temperature and pressure which increases core reactivity and can lead to a decrease of shutdown margin and departure from nucleate boiling ratio.

(2) Safety Objective:

To assure that (1) pressure in the reactor coolant and main steam lines is limited in order to protect the reactor coolant pressure boundary from overpressurization, (2) fuel damage is sufficiently limited so that the core will remain in place and intact with no loss of core cooling capability, (3) doses at the nearest exclusion area boundary are a small fraction of 10 CFR Part 100 guidelines, (4) ambient conditions do not exceed equipment qualification conditions (particularly nonsafety-grade equipment used to mitigate the accident), (5) the thermal and stress transients do not damage the reactor vessel, and (6) systems necessary for safe shutdown are not damaged by the accident.

(3) Status:

Investigation of the effects of high-energy line failures outside containment on other equipment was initiated as a generic issue in 1971 and all but a few facilities have been completed. New acceptance criteria have evolved during the review period. There was no similar investigation for failures inside containment. No reviews on operating plants of the effects on the reactor of concurrent steam generator or tube failure, or of blowdown of more than one steam generator have been performed.

(4) Reference:

Standard Review Plan, Section 15.1.5

TOPIC: XV-3 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulatory Failure (Closed)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve a decrease in secondary heat removal. The decrease in heat removal causes a suddent increase in system pressure and temperature.

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

The consequences associated with these transients are compared during each reload review to the consequences found to be acceptable during previous reload reviews.

(4) References:

Standard Review Plan, Sections 15.2.1 through 15.2.5

TOPIC: XV-4 Loss of Nonemergency AC Power to the Station Auxiliaries

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve the loss of nonemergency ac power (loss of offsite power or onsite ac distribution system) to station auxiliaries (for example, reactor coolant circulation pumps). This power loss will, within a few seconds, cause the turbine to trip and reactor coolant system to be isolated, which in turn causes the coolant pressure and temperature to increase.

(2) Safety Objective:

To assure that the pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

During each reload review by the staff, the previously determined limiting transient is reviewed to determine if new core parameters are more restrictive than the reference analysis parameter values.

(4) Reference:

Standard Review Plan, Section 15.2.6

TOPIC: XV-5 Loss of Normal Feedwater Flow

(1) Definition:

Review the assumptions, calculational models used, and consequences of the postulated loss of feedwater flow accidents, which cause an increase in coolant pressure and temperature.

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained.

(3) Status:

The consequences associated with these transients are compared during each reload review to the consequences found to be acceptable during previous reload reviews.

(4) Reference:

Standard Review Plan, Section 15.2.7

TOPIC: XV-6 Feedwater System Pipe Breaks Inside and Outside Containment (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated accidents which involve feedwater line breaks of different sizes. A feedwater line break, depending on size, may cause reactor system heatup (by reducing feedwater flow to the steam generator), or cooldown (by excessive energy discharge through the break).

(2) Safety Objective:

To assure that pressure in the reactor coolant and main steam systems is limited in order to protect the reactor coolant pressure boundary from overpressurization and that thermal margin for fuel integrity is maintained and that any radioactivity release would result in doses at the site boundary well within 10 CFR Part 100 guidelines.

(3) Status:

The identification of the most limiting transients and the consequences associated with these transients is evaluated during each reload review by the staff.

(4) Reference:

Standard Review Plan, Section 15.2.8

TOPIC: XV-7 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

(1) Definition:

Review the assumptions, calculational models, and consequences of seizure of the rotor or break of the shaft of a reactor coolant pump in a PWR or recirculation pump in a BWR. These accidents result in a sudden decrease in core coolant flow and corresponding degradation of core heat transfer and, in a PWR, an increase in primary system pressure. If clad failure is calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To assure that the consequences of a reactor coolant pump rotor seizure or reactor coolant pump shaft break are acceptable; that is, that no more than a small fraction of the fuel rods fail, that the radiological consequences are a small fraction of 10 CFR Part 100 guidelines, and that the system pressure is limited in order to protect the reactor coolant pressure boundary from overpressurization.

(3) Status:

Reviewed during each reload only if there is reason to believe that results would be different from the reference analysis; that is, only if a change in core parameters invalidates previous analyses.

(4) Reference:

Standard Review Plan, Section 15.3.3

TOPIC: XV-8 Control Rod Misoperation (System Malfunction or Operator Error)*

(1) Definition:

Review the licensee's description of rod position, flux, pressure, and temperature indication systems and the actions initiated by those systems which can mitigate the effects or prevent the occurrence of various misoperations. Review the descriptions of the input calculations and the calculational models used and the justification of their validity and adequacy. A transient of this type can result in achieving fuel melt temperatures and potential fuel damage.

(2) Safety Objective:

To assure that the consequences of this event do not exceed specified fuel design limits and that the protection system action be initiated automatically.

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*Reviewed for PWRs only; Standard Review Plan, Sections 15.4.1 and 15.4.2 cover BWRs and no additional areas considered.

(3) Status:

Reviewed during reload, Technical Specifications revised to compensate for changes in analytical results.

(4) Reference:

Standard Review Plan, Section 15.4.3

TOPIC: XV-9 Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate

(1) Definition:

Review BWRs for (1) startup of an idle recirculation pump and (2) a flow controller malfunction causing increased recirculation flow. Review PWRs with loop isolation valves for startup of a pump in an initially isolated inactive reactor coolant loop where the rate of flow increase is limited by the rate at which isolation valves open. For PWRs without loop isolation valves, review startup of a pump in any inactive loop. If clad failures are calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To verify that the plant responds in such a way that the criteria regarding fuel damage and system pressure are met (that is, no more than a small fraction of the fuel rods fail, that radiological consequences are a small fraction of 10 CFR Part 100 guidelines, and that the system pressure is limited in order to protect the reactor coolant pressure boundary from overpressurization.)

(3) Status:

PWRs reviewed against the final safety analysis report, BWR reviewed at each reload, Technical Specifications required to preclude exceeding safety limits during transients.

(4) Reference:

Standard Review Plan, Sections 15.4.4 and 15.4.5

TOPIC: XV-10 Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of moderator dilution. An accident of this type could result in a departure from nucleate boiling and a loss of shutdown margin.

(2) Safety Objective:

To confirm that the plant responds to the events in such a way that the criteria regarding fuel damage and system pressure are met and adequate time allowed for the operator to terminate the dilution before the shutdown margin is reduced. (Reactor coolant pressure and main steam pressure should be limited in order to protect the reactor coolant pressure boundary from overpressurization.) (Operator action must be initiated within 30 minutes following this event if refueling, and within 15 minutes during other modes of operation.)

(3) Status:

Only reviewed during initial operating-license review and not thereafter. The consequences may not have been calculated in accordance with current practice.

(4) Reference:

Standard Review Plan, Section 15.4.6

TOPIC: XV-11 Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (BWR)

(1) Definition:

Review the spectrum of misloading events analyzed to verify that the worst situation undetectable by incore instrumentation has been identified. This review will include an assessment of the plant's offgas and steam line radiation monitors to detect fuel damage and their capability to automatically isolate the offgas system when necessary.

(2) Safety Objective:

To assure that a misloaded assembly is detected and if undetected will not result in exceeding fuel safety limits or radioactive releases.

(3) Status:

Reviewed during reloads, Technical Specifications developed to limit consequences of worst misloaded assembly to small fraction of 10 CFR Part 100 guidelines. Technical Specifications setpoints for radiation monitors alarm/isolation signals have been found deficient and have been updated on a case-by-case basis for several plants.

(4) Reference:

Standard Review Plan, Section 15.4.7

TOPIC: XV-12 Spectrum of Rod Ejection Accidents (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences, including radiological consequences, of PWR control rod ejection accidents, and review the Technical Specifications regarding control of reactivity worth and technical specifications on primary to secondary leakage. Ejection of a control element assembly from the core can occur if the control element drive mechanism housing or the nozzle on the reactor vessel head breaks off circumferentially. The ejection of a control element assembly by the reactor coolant system pressure can cause a severe reactivity excursion. This accident may result in high doses for those plants where fuel failures are postulated to occur as a result of the accident. This accident usually determines the maximum allowable steam generator leak rate.

(2) Safety Objective:

To ensure that if a control element assembly ejection occurs, core damage is minimal, no additional reactor coolant pressure boundary failures occur, the calculated radial average energy density is limited to 280 cals/gm at any axial fuel location in any fuel rod, and that the radiological consequences will not exceed appropriate limits.

(3) Status:

Releases through the containment and/or steam generator leaks are analyzed for current plants, but were not reviewed routinely for older plants. Many of the operating plants have no leak Technical Specifications or they are excessively high. During each reload by the staff, the previously determined limiting transient is reviewed to determine if the new ejected rod worth is more restrictive than the reference analysis values.

(4) References:

1. Standard Review Plan, Section 15.4.8
2. Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors"

TOPIC: XV-13 Spectrum of Rod Drop Accidents (BWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of BWR control rod drop accidents and review the Technical Specifications regarding control of rod activity worth. An uncoupled rod may hang up in the core when the control rod drive is withdrawn and drop later when the consequences of a rapid control rod withdrawal are most severe. An analysis of the radiological consequences from this accident will be included.

(2) Safety Objective:

To limit the effects of a postulated control rod drop to the extent that reactor coolant pressure boundary stresses are not exceeded and core damage is minimal. To assure that the radial average fuel rod enthalpy at any axial location in any fuel rod is limited to less than 280 cals/gm following the worst reactivity excursion and to assure that the radiological consequences do not exceed appropriate guidelines.

(3) Status:

The potential for and reactivity consequences of an accidental control rod drop are now routinely evaluated prior to issuance of an operating license and any time thereafter when changes could affect the accident results or probability of occurrence. Radiological consequences may not have been calculated in accordance with present practice.

(4) Reference:

Standard Review Plan, Section 15.4.9

TOPIC: XV-14 Inadvertent Operation of Emergency Core Cooling System and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory

(1) Definition:

Review the assumptions, calculational models used, and consequences of actuation of the high pressure coolant injection system or faulty operation of the volume control system. The chemical and volume control system regulates both the chemistry and the quantity of coolant in the reactor coolant system. Changing the boron concentration in the reactor coolant system is a part of normal plant operation, compensating for long-term reactivity effects. Actuation of these systems could increase the volume of coolant within the reactor coolant pressure boundary (RCPB) causing a high water level, possible high power level, and high or low pressure. If clad failure is calculated, determine that offsite consequences are acceptable.

(2) Safety Objective:

To assure that water added to the RCPB does not cause transients that exceed RCPB pressure limits or result in unacceptable fuel damage. No activity is released during the transient, but the transient may subsequently result in increased radioactivity in gaseous releases during normal operation.

(3) Status:

This transient is now routinely analyzed prior to issuance of an operating license and any time thereafter when proposed changes would affect the transient results. Radiological consequences may not have been calculated in accordance with current practice.

(4) Reference:

Standard Review Plan, Section 15.5.1

TOPIC: XV-15 Inadvertent Opening of a PWR Pressurizer Safety/Relief Valve or a BWR Safety/Relief Valve

(1) Definition:

Review the assumptions, calculational models used, and consequences of inadvertent opening of a PWR pressurizer safety/relief valve or a BWR safety/relief valve. Loss of reactor coolant inventory and depressurizing action of the reactor coolant system can occur if the PWR pressurizer safety/relief valve or the BWR safety/relief valves open spuriously, or open when required but fail to reclose properly.

(2) Safety Objective:

To preserve fuel cladding integrity during reactor coolant system depressurization transients resulting from faulty operation of a relief or safety valve while at rated power.

(3) Status:

The transient is now evaluated prior to issuance of an operating license and any time thereafter when proposed changes could affect the transient results.

(4) References:

1. Standard Review Plan, Section 15.5.1
2. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants"

TOPIC: XV-16 Radiological Consequences of Failure of Small Lines Carrying Primary Coolant Outside Containment

(1) Definition:

Review the assumption, calculational models used, and radiological consequences of failure of small lines carrying primary coolant outside containment and review the Technical Specifications associated with primary coolant radioactivity concentrations, isolation valve closure times, and isolation valve leakage limits. In the event of a rupture of any component in the instrument lines outside primary containment, primary coolant and any radioactivity contained in the coolant or released to the coolant during the transient will be released if the instrument lines are connected to the reactor coolant pressure boundary. Primary coolant sample lines if broken outside primary containment can also allow coolant and radioactivity in the coolant to escape in the same manner. When these lines discharge to secondary containment, the integrity of the secondary containment and the efficiency of the filtration systems must be determined.

(2) Safety Objective:

To assure that any release of radioactivity to the environment is substantially below the guidelines of 10 CFR 100.

(3) Status:

The radiological consequences of small line breaks outside of primary containment have been evaluated routinely since 1970 prior to issuance of operating licenses, but have not always included the effects of iodine spikes during the depressurization transient.

(4) References:

1. Regulatory Guide 1.11, "Instrument Lines Penetrating Primary Reactor Containment"
2. 10 CFR Part 50, Appendix A, GDC 55 and 56
3. Standard Review Plan, Section 15.6.2

TOPIC: XV-17 Radiological Consequences of Steam Generator Tube Failure (PWR)

(1) Definition:

Review the assumptions, calculational models used, and consequences of a steam generator tube failure with and without loss of offsite power and review the Technical Specifications associated with coolant activity concentrations. Steam generator tube failures allow escape of reactor coolant into the main steam system and to the environment. An analysis of the radiological consequences of this accident will be included.

(2) Safety Objective:

To assure that the plant responds in a proper manner to this accident, including appropriate operator actions, and to assure that radioactivity released following steam generator tube failure(s) is a small fraction of the 10 CFR 100 guidelines and within 10 CFR 100 for the case of a coincident iodine spike.

(3) Status:

The iodine release mechanism may not have been analyzed in accordance with present assumptions and methods for some of the older PWRs. Some operating plants do not have iodine activity limits in their Technical Specifications or have inappropriately high limits.

(4) References:

1. Standard Review Plan, Section 15.6.3
2. Regulatory Guide 1.5, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Steam Line Break Accident for Boiling Water Reactors"

TOPIC: XV-18 Radiological Consequences of Main Steam Line Failure Outside Containment

(1) Definition:

Review the assumptions, calculational models used, and consequences of failure of a main steam line outside containment and review the Technical Specifications associated with primary coolant activity concentrations and main steam isolation valve closure times.

(2) Safety Objective:

A steam line break outside containment allows radioactivity to escape to the environment. To limit the release of radioactivity to the environment to well within the guidelines of 10 CFR 100 in the event of a large steam line break, the primary coolant radioactivity must be appropriately limited by Technical Specifications.

(3) Status:

Some operating plants do not have appropriate coolant activity Technical Specifications.

(4) Reference:

Standard Review Plan, Section 15.6.4

TOPIC: XV-19 Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

(1) Definition:

Review the licensee's analyses of the spectrum of loss-of-coolant accidents (LOCAs) including break locations, break sizes, and initial conditions assumed, the evaluation model used, failure modes, radiological consequences, acceptability of auxiliary systems, functional capability of the containment, and the effects of blowdown loads. LOCAs are postulated breaks in the reactor coolant pressure boundary resulting in a loss of reactor coolant at a rate in excess of the capability of the reactor coolant makeup system. LOCAs result in excessive fuel damage or melt unless coolant is replenished.

(2) Safety Objective:

To assure that the consequences of loss-of-coolant accidents are acceptable; that is, that the requirements of 10 CFR 50.46 and Appendix K to 10 CFR 50 are met, that the radiological consequences of a design basis loss-of-coolant accident from containment leakage and the radiological consequences of leakage from engineered safety features outside containment are acceptable, and the structural effects of blowdown are acceptable.

(3) Status:

Emergency core cooling system (ECCS) evaluation is a generic item which is currently under review or is complete for all operating reactors (La Crosse and San Onofre have stainless steel cores and have analyses completed to show conformance with the Interim Acceptance Criteria). Related generic items currently under review are reevaluations for increased vessel head fluid temperatures in W PWRs, effects of core flow on BWR LOCA analyses, GE ECCS input errors, and non-jet pump BWR core spray cooling coefficients. Radiological consequences are not routinely rereviewed.

(4) Reference:

Standard Review Plan, Section 15.6.5 and its Appendices

TOPIC: XV-20 Radiological Consequences of Fuel-Damaging Accidents (Inside and Outside Containment)

(1) Definition:

Review the assumptions, calculational models used, and consequences of postulated fuel damaging accidents inside and outside containment and review Technical Specifications associated with fuel handling and ventilation system and filter systems, including interlocks on fuel movement and damage from fuel cask drop and tipping. Include in the review the assumed activity available for release, decontamination factors, filter efficiencies, activity transport mechanisms and rates, ventilation system potential release pathways, and calculated doses.

(2) Safety Objective:

To assure that offsite doses resulting from fuel damaging accidents, resulting from fuel handling, or dropping a heavy load on fuel are well within the guideline values of 10 CFR Part 100.

(3) Status:

The radiological consequences of fuel handling accidents inside containment are currently being performed as a generic review for PWRs. The radiological consequences of fuel damaging accidents outside containment of operating plants are only evaluated if Technical Specifications are reviewed.

(4) References:

1. Standard Review Plan, Section 15.7.4
2. Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors"

TOPIC: XV-21 Spent Fuel Cask Drop Accidents

(1) Definition:

Review the potential for spent fuel cask drops, the damage which could result from cask drops, and the radiological consequences of a cask drop from fuel damaged within the cask under conditions exceeding the design basis impact on the cask.

(2) Safety Objective:

To assure that the damage to fuel within the casks and radiological consequences resulting from a cask drop are acceptable or that acceptable measures have been taken to preclude cask drops.

(3) Status:

Fuel cask drop analysis is a generic item which has been completed on some plants or is currently under review for all other operating reactors.

(4) References:

1. Standard Review Plan, Section 15.7.4
2. Regulatory Guide 1.25 "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors"
3. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book)

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-36, "Control of Heavy Loads Near Spent Fuel" (NUREG-0649)

  The review criteria required by USI A-36 (Standard Review Plan, Section 15.7.5) are identical to the review criteria specified in the References of SEP Topic IX-2; therefore, this SEP topic has been deleted.

TOPIC: XV-22 Anticipated Transients Without Scram

(1) Definition:

Review the postulated sequences of events, analytical models, values of parameters used in the analytical models, and the predicted results and consequences of events in which an anticipated transient occurs and is not followed by an automatic reactor shutdown (scram). Analyses of the radiological consequences for these transients will be included. Failure of the reactor to shut down quickly during anticipated transients can lead to unacceptable reactor coolant system pressures and to fuel damage.

(2) Safety Objective:

To assure that the reliability of the reactor shutdown systems is high enough so that anticipated transient without scram (ATWS) events need not be considered or to assure that the consequences of ATWS events are acceptable; that is, that the reactor coolant system pressure, fuel pressure, fuel thermal and hydraulic performance, maximum containment pressure, and radiological consequences are within acceptable limits.

(3) Status:

ATWS is a generic topic currently under review to determine a position for all power reactors. BWR licensees have been requested to install reactor coolant pump trips as a short-term program measure. All licensees have submitted descriptions of the applicability of vendor generic ATWS reports for their plants. The schedule for review of Class C plants, which includes those plants designated for Phase II of SEP, has not yet been developed.

(4) References:

1. NUREG-0328, "Regulatory Licensing: Status Summary Report" (Pink Book)
2. WASH 1270, "Technical Report on Anticipated Transients Without Scram for Water-Cooled Power Reactors," September 1973
3. Standard Review Plan, Section 15.8 and Appendix

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-9, "Anticipated Transients Without Scram" (NUREG-0606)

  The reference cited in this topic, that is, NUREG-0328, was the precursor of USI A-9. The evaluation required for USI A-9 is identical to SEP Topic XV-22; therefore, this SEP topic has been deleted.

TOPIC: XV-23 Multiple Tube Failures in Steam Generators

(1) Definition:

Assess the effects of multiple steam generator tube failures (ranging from leaks to double-ended ruptures) as a result of pressure differentials that may occur following a loss-of-coolant accident (LOCA), steam line break, or anticipated transient without scram (ATWS) events.

(2) Safety Objective:

Assure that the reflood of the core following a LOCA is possible and that the radiological consequences following these accidents are within the 10 CFR Part 100 guidelines.

(3) Status:

The consequences of multiple tube failures have not been analyzed for any plant at the licensing stage. Work has been done for some operating plants, but ultimate goals have yet to be set.

(4) References:

1. Prairie Island Nuclear Station, Docket Nos. 50-282 and 50-306
2. Turkey Point Plant, Docket Nos. 50-250 and 50-251
3. Surry Power Stations, Units 1 and 2, Docket Nos. 50-280 and 50-281

(5) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

(a) USI A-3, A-4, A-5, "Westinghouse, Combustion Engineering, Babcock and Wilcox Steam Generator Tube Integrity" (NUREG-0649)

Two of the tasks of USI A-3, A-4, A-5 are as follows:

1. Analyses of LOCA with Concurrent Steam Generator Tube Failures
2. Analyses of Main Steam Line Break

The analyses required by these two tasks in USI A-3, A-4, A-5 cover two of the three events specified in the Definition.

(b) USI A-9, "Anticipated Transients Without Scram" (NUREG-0606)

Pressure differentials resulting from ATWS events have been determined to be no greater than those resulting from main steam line break events (NUREG-0460, Volume 2, Appendix V). The analysis for ATWS event is, therefore, covered under USI A-3, A-4, and A-5.

The evaluation required for USI A-3, A-4, A-5 is identical to SEP Topic XV-23; therefore, this SEP topic has been deleted.

TOPIC: XV-24 Loss of All AC Power

(1) Definition:

Review plant systems to determine that following loss of all ac power (onsite and offsite) the reactor is shut down and core cooling can be initiated. Loss of all ac power causes loss of most emergency equipment and instrumentation.

(2) Safety Objective:

To assure that with only dc power, equipment design, diversity, and operator action are sufficient to initiate core cooling within a short time period (typically 20 minutes).

(3) Status:

Not an explicit SRP topic. Availability of some ac power is assumed in all accident/transient analyses. Topic may be considered as an auxiliary fuel pump or reactor core isolation cooling pump diversity spinoff.

(4) Basis for Deletion (Related TMI Task, USI, or Other SEP Topic):

- USI A-44, "Station Blackout" (NUREG-0606)

  The problem description of USI A-44 is identical to the Definition of SEP Topic XV-24, and the review of USI A-44 would be the same as Topic XV-24; therefore, this SEP topic has been deleted.

TOPIC: XVI Technical Specifications

(1) Definition:

The existing Technical Specifications, associated with SEP topics, will be compared with the Standard Technical Specifications for deviations. Where significant differences exist, they will be identified and considered for upgrading. The bases for the specifications will be examined including trip setpoints and accounting for nuclear uncertainty. Where significant voids occur in existing specifications, appropriate values will be identified and considered for upgrading.

(2) Safety Objective:

To assure that the safety limits and operational safety measures are sufficiently specified for the plant to minimize the probability of accidents that could result from equipment failure, misoperation, or human error.

(3) Status:

See Topic XIII-1, "Conduct of Operations" for Section VI status. The other sections of the Technical Specifications are reviewed only to the extent that reloads, license amendments, or generic problems require.

(4) References:

1. Standard Technical Specifications; Regulatory Guide 1.8, "Personnel Selection and Training," and Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)"
2. Standard Review Plan
3. Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants," Chapter 16
4. 10 CFR Part 50, Section 50.36

TOPIC: XVII Operational Quality Assurance Program

(1) Definition:

Review the Quality Assurance (QA) Program with respect to safe and reliable operation of the plant.

(2) Safety Objective:

Since 1973, significant new guidance for operational QA programs in the form of Regulatory Guides and WASH documents has been issued describing how to meet the criteria of 10 CFR Part 50, Appendix B. The objective of this guidance is to assure that operation, maintenance, modification, and test activities do not degrade the capability of safety-related items to perform their intended functions.

(3) Status:

Generic review for compliance with current standards is under way. As of May 1977, 50 of the 63 operating plants have QA programs which meet current criteria. The 13 remaining plants are currently under review, with an estimated completion date of July 1977.

(4) References:

1. 10 CFR Part 50, Appendix B
2. WASH-1283, Revision 1, "Guidance on Quality Assurance Requirements During Design and Procurement Phase of Nuclear Power Plants," May 24, 1974
3. WASH-1284, "Guidance on Quality Assurance Requirements During the Operations Phase of Nuclear Power Plants," October 26, 1973

4. WASH-1309, "Guidance on Quality Assurance Requirements During the Construction Phase of Nuclear Power Plants," May 10, 1974
5. American National Standards Institute, ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," February 19, 1976

U.S. Nuclear Regulatory Commission reports cited under "Basis for Deletion" include:

NUREG-75/111	Guide and Checklist for Development and Evaluation of State and Local Government Radiological Emergency Response Plans in Support of Fixed Nuclear Facilities" (Reprint of WASH-1293), Oct. 1975.
NUREG-0153	"Staff Discussion of 12 Additional Technical Issues Raised by Responses to November 3, 1976 Memorandum from Director, NRR, to NRR staff," 1976.
NUREG-0313	"Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," July 1977.
NUREG-0328	"Regulatory Licensing: Status Summary Report" (Pink Book).
NUREG-0371	"Approved Category A Task Action Plans," Nov. 1977.
NUREG-0410	"NRC Program for the Resolution of Generic Issues Related to Nuclear Power Plants, Report to Congress," Dec. 1977.
NUREG-0460	"Anticipated Transients Without Scram for Light Water Reactors," Vol. 2, Apr. 1978.
NUREG-0471	"Generic Task Problem Descriptions - Category B, C, and D Tasks," Sept. 1978.
NUREG-0484	"Methodology for Combining Dynamic Responses," May 1980.
NUREG-0510	"Identification of Unresolved Safety Issues Relating to Nuclear Power Plants--A Report to Congress 1979," Jan. 1979.
NUREG-0554	"Single-Failure-Proof Cranes for Nuclear Power Plants," May 1979.
NUREG-0577	"Potential for Low Fracture Toughness and Lamellar Tearing on PWR Steam Generator and Reactor Coolant Pump Supports," Sept. 1979.
NUREG-0606	"Unresolved Safety Issues Summary," issued quarterly.
NUREG-0609	"Asymmetric Blowdown Loads on PWR Primary Systems, Resolution of Generic Task Action Plan A-2," Jan. 1981.
NUREG-0649	"Task Action Plan for Unresolved Safety Issues Related to Nuclear Power Plants," Feb. 1980.

NUREG-0654	"Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," Feb. 1980.
NUREG-0660, Rev. 1	"NRC Action Plan Developed as a Result of the TMI-2 Accident," Vols. 1 and 2, May 1980.
NUREG-0691	"Investigation and Evaluation of Cracking Incidents in Piping in Pressurized Water Reactors," Sept. 1980.
NUREG-0705	"Identification of New Unresolved Safety Issues Relating to Nuclear Power Plants," Mar. 1981.
NUREG-0737	"Clarification of TMI Action Plan Requirements," Nov. 1980.
NUREG-0800	"Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," July 1981 (formerly NUREG-75/087).
NUREG/CR-1321	"Final Report - Phase I. Systems Interaction Methodology Applications Program," Apr. 1980.

APPENDIX B

SEP TOPICS DELETED BECAUSE THEY ARE
COVERED BY A TMI TASK, UNRESOLVED SAFETY
ISSUE (USI), OR OTHER SEP TOPIC[1,2]

[1]See "Basis for Deletion" in Appendix A under applicable SEP topic.
[2]Letter from G. C. Lainas (NRC) to all SEP licensees, Subject: Deletion of Systematic Evaluation Program Topics Covered by Three Mile Island NRC Action Plan, Unresolved Safety Issues, or Other SEP Topics, May 1981.

SEP Topic No.	SEP Title	TMI, USI, or SEP No.	TMI, USI, or SEP Title
II-2.B	Onsite Meteorological Measurements Program	TMI II.F.3 TMI III.A.1	Instrumentation for Monitoring Accident Conditions Improve Licensee Emergency Preparedness - Short Term
II-2.D	Availability of Meteorological Data in the Control Room	TMI II.F.3 TMI III.A.1 TMI I.D.1	Instrumentation for Monitoring Accident Conditions Improve Licensee Emergency Preparedness - Short Term Control Room Design Reviews
III-8.D	Core Supports and Fuel Integrity	USI A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant System
III-9	Support Integrity	USI A-12 USI A-7 USI A-24 USI A-46 SEP III-6 SEP V-1	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports Mark I Containment Long-Term Program Environmental Qualification of Safety-Related Equipment Seismic Qualification of Equipment in Operating Plants Seismic Design Considerations Compliance With Codes and Standards (10 CFR Part 50, Section 50.55a)
III-11	Component Integrity	USI A-46 USI A-2 SEP III-6	Seismic Qualification of Equipment in Operating Plants Asymmetric Blowdown Loads on Reactor Primary Coolant Seismic Design Considerations
III-12	Environmental Qualification of Safety-Related Equipment	USI A-24	Qualification of Safety-Related Equipment
V-4	Piping and Safe-End Integrity	USI A-42	Pipe Cracks in Boiling Water Reactors
V-13	Waterhammer	USI A-1	Waterhammer
VI-2.A	Pressure-Suppression-Type BWR Containments	USI A-7	Mark I Containment Long-Term Program
VI-2.B	Subcompartment Analysis	USI A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant System
VI-5	Combustible Gas Control	TMI II.B.7 USI A-48	Analysis of Hydrogen Control Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment
VI-7.E	Emergency Core Cooling System Sump Design and Test for Recirculation Mode Effectiveness	USI A-43	Containment Emergency Sump Reliability
VI-8	Control Room Habitability	TMI III.D.3.4	Control Room Habitability Requirements
VII-4	Effects of Failure in Nonsafety-Related Systems on Selected Engineered Safety Features	USI A-47 USI A-17	Safety Implications of Control Systems Systems Interactions in Nuclear Power Plants
VII-5	Instruments for Monitoring Radiation and Process Variables During Accidents	TMI II.F.1 TMI II.F.2 TMI II.F.3	Additional Accident Monitoring Instrumentation Identification of and Recovery From Conditions Leading to Inadequate Core Cooling Instruments for Monitoring Accident Conditions
IX-2	Overhead Handling Systems (Cranes)	USI A-36	Control of Heavy Loads Near Spent Fuel Pool
XIII-1	Conduct of Operations	TMI I.C.6 TMI III.A.1 TMI III.A.2	Procedures for Verification of Correct Performance of Operating Activities Improve Licensee Emergency Preparedness - Short-Term Improving Licensee Emergency Preparedness - Long-Term
XV-21	Spent Fuel Cask Drop Accidents	USI A-36	Control of Heavy Loads Near Spent Fuel Pool
XV-22	Anticipated Transients Without Scram	USI A-9	Anticipated Transients Without Scram
XV-24	Loss of All AC Power	USI A-44	Station Blackout

APPENDIX C

PLANT-SPECIFIC SEP TOPICS DELETED, REFERENCE LETTER, AND REASON FOR DELETION

SEP Topic No.	SEP title	Date of letter	Reason for deletion of topic
II-4.E	Dam Integrity	11/16/79	Not applicable to site.
III-3.B	Structural and Other Consequences (e.g., Flooding of Safety-Related Equipment in Basements) of Failure of Underdrain Systems	11/16/79	Not applicable to site because site does not have a system whose function is to lower the groundwater table.
III-7.A	Inservice Inspection, Including Prestressed Concrete Containments With Either Grouted or Ungrouted Tendons	11/16/79	Not applicable to this unit's containment design.
III-7.C	Delamination of Prestressed Concrete Containment Structures	11/16/79	Not applicable to this unit's containment design.
III-8.B	Control Rod Drive Mechanism Integrity	9/11/80	Review published as NUREG-0479, "Report on BWR Control Rod Drive Failures."
III-10.B	Pump Flywheel Integrity	11/16/79	Not applicable to BWRs.
V-1	Compliance With Codes and Standards	11/27/81	Reviewed under inservice inspection/inservice test program.
V-2	Applicability of Code Cases	11/16/79	Not applicable at this time; to be reviewed for any future modifications using references to Code Cases.
V-3	Overpressurization Protection	11/16/79	Not applicable to BWRs, based on operating experience.
V-7	Reactor Coolant Pump Overspeed	11/16/79	Not applicable to BWRs.
V-8	Steam Generator Integrity	11/16/79	Not applicable to BWRs.
V-9	Reactor Core Isolation Cooling System (BWR)	11/16/79	Not applicable to this facility design.
VI-2.C	Ice Condenser Containment	11/16/79	Not applicable to this unit's containment design.
VI-7.A.1	Emergency Core Cooling System Reevaluation To Account for Increased Reactor Vessel Upper-Head Temperature	11/16/79	Not applicable to BWRs.
VI-7.A.2	Upper Plenum Injection	11/16/79	Not applicable to BWRs.
VI-7.B	Engineered Safety Feature Switchover From Injection to Recirculation Mode (Automatic Emergency Core Cooling System Realignment)	11/16/79	Not applicable to BWRs.
VI-7.C.3	Effect of PWR Loop Isolation Valve Closure During a Loss-of-Coolant Accident on Emergency Core Cooling System Performance	11/16/79	Not applicable to BWRs.
VI-7.F	Accumulator Isolation Valves Power and Control System Design	11/16/79	Not applicable to BWRs.
VI-9	Main Steam Line Isolation Seal System (BWR)	11/16/79	Not applicable to this facility design.
VII-7	Acceptability of Swing Bus Design on BWR-4 Plants	11/16/79	Not applicable to this facility design.
IX-4	Boron Addition System (PWR)	11/16/79	Not applicable to BWRs.
X	Auxiliary Feedwater System	11/16/79	Not applicable to BWRs.
XI-1	Appendix I	12/4/81	Being resolved under generic activities A-02, "Appendix I," and B-35, "Confirmation of Appendix I Models." (See "Basis for Deletion" in Appendix A under Topic XI-1.)

SEP Topic No.	SEP title	Date of letter	Reason for deletion of topic
XI-2	Radiological (Effluent and Process) Monitoring Systems	12/4/81	Being resolved under generic activities A-02, "Appendix I." (See "Basis for Deletion" in Appendix A under Topic XI-2.)
XV-2	Spectrum of Steam System Piping Failures Inside and Outside Containment (PWR)	11/16/79	Not applicable to BWRs.
XV-6	Feedwater System Pipe Breaks Inside and Outside Containment (PWR)	11/16/79	Not applicable to BWRs.
XV-10	Chemical and Volume Control System Malfunction That Results in a Decrease in Boron Concentration in the Reactor Coolant (PWR)	11/16/79	Not applicable to BWRs.
XV-12	Spectrum of Rod Ejection Accidents (PWR)	11/16/79	Not applicable to BWRs.
XV-17	Radiological Consequences of Steam Generator Tube Failure (PWR)	11/16/79	Not applicable to BWRs.
XV-23	Multiple Tube Failures in Steam Generators	11/16/79	Not applicable to BWRs.
XVI	Technical Specifications	11/5/80	Will be addressed after completion of the integrated assessment.

APPENDIX D

PROBALISTIC RISK ASSESSMENT STUDY

The Effect of Resolution of the Millstone Point Unit 1 Systematic Evaluation Program Issues on Probabilistic Calculations of Risk

SAND82-2429

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Executive Summary

This preliminary section of the report "The Effect of Resolution of the Millstone Point Unit 1 Systematic Evaluation Program Issues on Probabilistic Calculations of Risk" is an executive summary describing the analysis and results for each issue. We have recalculated the core melt frequency, expected exposure, and risk using the Interim Reliability Evaluation Program (IREP) Probabilistic Risk Assessment (PRA) of the Millstone-1 nuclear power plant after changing the IREP PRA model to represent resolution of each issue. The details of the methodology are given in the main text of this report.

The overall results of the analysis are given in Table Ex-1. The decrease in core melt frequency, expected exposure (man-rem/Reactor-year), and ratio of risk (new risk/old risk) is given for the resolution of each issue. Below are brief descriptions of the analysis and results for each issue.

Table Ex-1
Results of Issue Analysis

Issue	Decrease in Core Melt Frequency (1) $(R\text{-}yr)^{-1}$	Decrease in Exposure (2) (man-rem/R yr)	New Risk/Old Risk
III-5.B	(3)		
III-8.A	0.0	0.0	1.0
III-10.A	3×10^{-6}	3	0.996
V-5	3×10^{-6}	16	0.98
V-10.B	0.0	0.0	1.0
V-11.A	4×10^{-7}	3	0.991
VI-4	0.0	0.0	1.0
VI-6	0.0	0.0	1.0
VI-7.A.3	0.0	0.0	1.0
VI-7.C.1 } VII-3 }	3×10^{-5}	90	0.84
VI-10.A	0.0	0.0	1.0
VII-1.A	0.0	0.0	1.0
VIII-2	1×10^{-6}	3	0.995
VIII-3.A	(4)		
VIII-3.B	1.7×10^{-6}(5) 7.4×10^{-6}(6)	2(5) 8(6)	0.997(5) 0.987(6)
IX-3	0.0	0.0	1.0
IX-5	0.0	0.0	1.0
XV-1	0.0	0.0	1.0
XV-3	0.0	0.0	1.0
XV-18	0.0	0.0	1.0

(1) Total core melt frequency = 3×10^{-4}/Reactor-year
(2) Total expected exposure = 550 man-rem/Reactor-year
(3) Information to analyze this issue not received from utility.
(4) Issue could reduce battery unavailability, at most, by a factor of 16. Effect on risk outside scope of this analysis.
(5) Without decrease in maintenance unavailability.
(6) With decrease in maintenance unavailability.

III-5.B Pipe Break Outside Containment

This issue was not analyzed, although we had planned to evaluate it, because plant-specific information necessary for our analysis was not received from the utility.

III-8.A Loose Parts Monitoring and Core Barrel Vibration Monitoring

10 CFR Part 50.36 and Part 50 (GDC 13) as implemented by SRP 4.4 and Regulatory Guide 1.133, require a program for the monitoring of loose parts within the Reactor Coolant Pressure Boundary. Millstone-1 does not have such a program. Loose parts can cause transient events by causing damage within the reactor coolant system. However, the historical transient rate is high enough with a negligable contribution to that rate by loose parts to ensure that eliminating the loose-parts-induced transients will have no effect on core melt frequency, exposure, or risk.

III-10.A Thermal-Overload Protection for Motors of Motor-Operated Valves (MOVs)

10 CFR Part 50 (GDC 13) as implemented by Regulatory Guide 1.106 requires that the thermal-overload protection devices for MOVs should be bypassed during accident conditions or have their trip setpoints conservatively set. At Millstone-1, twelve of the safety-related MOVs which are not normally in their emergency positions have thermal-overload protection devices which are not bypassed by an emergency signal and it has not been shown that their trip setpoints were conservatively set. The systems affected are the Service Water System and Isolation Condenser Makeup System. Spurious operation of the thermal overload protection device will add to the unavailability of the MOV. Eliminating this contribution reduces the unavailability of an MOV by 14 percent, from 1×10^{-3} to 8.6×10^{-4}. Using the reduced data to requantify the dominant IREP Millstone-1 accident sequences results in a reduction in overall core melt frequency by 1 percent, exposure by 0.5 percent, and risk by 0.4 percent.

V-5 Reactor Coolant Pressure Boundary Leakage Detection

Systems required by Regularity Guide 1.45 to measure leakage from the reactor coolant pressure boundary to the containment at Millstone-1 do not meet the criteria because they are not testable during normal operation, they do not have the required sensitivity, their operability requirements are not imposed by Technical Specifications, and some do not have the required seismic qualification. The hypothesis is that small LOCAs will begin as leaks (leak-before-break) and improved leakage detection can lead to prevention of some LOCAs. There are many unknowns which would affect the analysis of the impact of leakage detection on the small LOCA frequency, perhaps the most important of which is the time it would take a detectable leak to become a break. Previous analyses of this SEP issue for the Oyster Creek[5] and Dresden-2[6] nuclear power plants (BWRs somewhat similar to Millstone-1) showed that the small LOCA frequency was dominated by pipe breaks and that resolution of this issue (prevention of some pipe breaks) could reduce the small LOCA frequency from the usual value of 1×10^{-3}/R-yr. There were no dominant accident sequences in the IREP PRA which were initiated by LOCAs. In fact, there was only one nondominant small LOCA sequence analyzed in detail. Eliminating this sequence by preventing <u>all</u> pipe breaks with improved leakage detection would decrease the core melt frequency by 1 percent, the exposure by 3 percent, and the risk by 2 percent. The alternate failure mode where a pressure transient could cause a leak (which would otherwise not grow) to become a break if the transient occurred before the leak was detected, and the plant shutdown, was not considered.

V-10.B RHR Reliability

10 CFR 50 (GDC 19 and 34) as implemented by SRP 5.4.7, BTB RSB 5-1, and Regulatory Guide 1.139, require that the plant can be taken from normal operating conditions to cold shutdown using only safety-grade systems, assuming a single failure and utilizing either onsite or offsite power through the use of suitable procedures. Millstone-1 has the safety-grade systems required to comply with the criteria but does not have procedures to reach cold shutdown using only safety grade systems (or from outside the control room). PRA studies to date, including the Reactor Safety Study and the IREP Millstone-1 study, have examined only accident sequences where there is a failure to reach hot shutdown. In doing this, there is a well reasoned assumption that the dominant part of the risk is involved in getting to hot shutdown. Thus, this issue has no effect on the IREP Millstone-1 calculation of core melt frequency, exposure, or risk.

V-11.A Requirements for Isolation of High and Low Pressure Systems

The reactor water cleanup system does not meet current licensing criteria (10 CFR 50, GDC 15, as implemented by BTP ICSB-3) for the isolation of this system from the reactor coolant system. The "redundant" isolation valves on the suction line of the reactor water cleanup system receive their isolation signal from the same pressure sensor. Failure of the isolation would lead to an interfacing system LOCA, core melt, and release in BWR release category 2. Resolution of this issue would decrease the core melt frequency by 0.1 percent, the exposure by 0.5 percent, and the risk by 1 percent.

VI-4 Containment Isolation System
VI-6 Leak Testing

These issues address the adequacy of containment integrity during accident conditions. Because of the small size and (relatively) low design pressure of the Millstone-1 containment, the pressure generated by steam and noncondensible gases during a core melt will fail the containment if no other failure mechanism occurs first. The dominant portion of the risk from nuclear power plants is from core melt accidents, not other (low consequence) releases such as those due to non-core-melt accidents. Because of the characteristics and relative consequences of leakage releases and containment ruptures by overpressure, no benefit can be achieved by increasing the reliability of isolation of the containment since it will fail by overpressure anyway. Therefore, resolution of this issue has no effect on core melt frequency, exposure, or risk.

VI-7.A.3 ECCS Actuation System

At Millstone-1, the Technical Specifications do not require testing of the Core Spray System pump space coolers and the tests of the LPCI System does not demonstrate that the Station Emergency Service Water System (ESW), which cools the LPCI heat exhangers, will start when LPCI is initiated. These are deviations from 10 CFR 50.55a(h) as implemented by IEEE Std. 279-1971 and 10 CFR 50 Appendix A (GDC 37) as implemented by Regulatory Guide 1.22. The IREP Millstone-1 study determined that space cooling was not necessary for the core spray pumps to perform their function. The ESW is manually actuated, so testing for automatic start of ESW when LPCI is initiated is not possible. However, implementing automatic actuation of ESW and testing it would eliminate operator error from possible failure mechanisms of ESW. Reducing this operator failure data had no effect on core melt frequency, exposure, or risk.

VI-7.C.1 Appendix K--Electrical Instrumentation and Control (EIC) Re-reviews.

VII-3 Systems Required for Safe Shutdown

Issue VI-7.C.1 identifies conditions which would result in transfering loads between redundant sources. These are motor control centers 2-3NE, 2A-3NE, and 22A-1, and the 120V ac instrument bus, which have automatic bus transfers (ABTs), and three dc load centers which can be manually transferred between redundant sources with no interlocks to prevent operator error which parallels the dc buses to a single emergency source. Issue VII-3 identifies concerns related to existence of only a single instrument ac bus instead of redundant buses.

Our analysis of these issues assumed that both would be resolved simultaneously since redundancy of instrument ac would require removal of the ABT. System design changes necessary to resolve the issues were modeled into the IREP Millstone-1 fault trees and the dominant accident sequence frequencies were recalculated. This decreased the core melt frequency by 10 percent, the exposure by 16 percent, and the risk by 14 percent. It appears that redundancy of the instrument ac bus contributed most of the improvement.

VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing

The Reactor Protection System (RPS) is not required to be tested as frequently as current licensing criteria demand. In addition, response time testing is not performed on the RPS. The tests (other than response time testing) are performed as often as the licensing criteria require, but the test frequency is not enforced by Technical Specifications. The actual frequency of testing was modeled in the IREP PRA, so creating new Technical Specifications would not change the risk calculation.

The time limit for RPS actuation, to make the reactor subcritical in time to allow other safety systems to prevent core melt, is on the order of minutes. Response time testing would detect delays in actuation on the order of seconds which, from a risk perspective, are successes of the RPS. The functional tests are sufficient to determine component and system operability. Thus there is no effect on core melt frequency, exposure, or risk due to resolution of this issue.

VII-1.A Isolation of the Reactor Protection System From Nonsafety Systems, Including Qualifications of Isolation Devices

There are no isolation devices between the nuclear flux monitoring systems, and the process recorders and indicating instruments. Isolation devices are not provided to isolate the APRM System from the process computer. In addition, power supplies for the RPS channels are not IE equipment and there is inadequate isolation between each RPS channel and its power supply. These are deviations from 10 CFR 50.55a(h). We did not analyze the effect of inadequate isolation between the RPS and its power supply. Even if the entire nuclear monitoring system were always failed, failure of the RPS is dominated by common mode mechanical faults. Thus resolution of this issue has no effect on core melt frequency, exposure, or risk.

VIII-2

The nonessential protective trips of the gas turbine generator are not bypassed under accident conditions (and do not have redundant sensors or coincident logic) as required by 10 CFR Part 50 Appendix A (GDC 17). Also, the gas turbine generator annunciators are not divided into disabling and nondisabling faults with notification on the "disabling" annunciator that the generator is unable to start as required by IEEE Std. 279-1971 (Section 4.20).

The plant operating procedures require the operator to verify that the emergency ac power supplies auto-start. If they have not, the operator is to attempt to start the diesel and/or gas turbine. Since the procedures require the operator to attempt to start the gas turbine if it does not start automatically, and since the IREP PRA does not give credit for operator action if it fails to start automatically, separation of the annunciators into disabling and nondisabling faults would not affect the risk calculation.

Bypassing nonessential trips of the gas turbine would eliminate spurious trips as contributors to the gas turbine unavailability. This would decrease the gas turbine unavailability from 6.0×10^{-2} to 5.9×10^{-2}. Requantification of the dominant accident sequences with this data resulted in a 0.3 percent decrease in core melt frequency, 0.5 percent decrease in exposure, and 0.5 percent decrease in risk.

VIII-3.A Station Battery Test Requirements

The Millstone-1 Technical Specifications do not require a station battery service test as demanded by 10 CFR 50 (GDC/18). The IREP Millstone-1 PRA assessed that the weekly specific gravity and voltage tests are sufficient to assure that the batteries had not failed since the last test. If the NRC assessment is correct, and service tests of the batteries are required to assure performance of the batteries under emergency conditions, then, in the extreme, all battery testing to date may have been ineffective. Because the IREP PRA was used as the base case to compare requantified sequences against, our methodology assumes that the analysis contained in that study is correct. Thus we cannot quantitatively assess this issue's effect on risk. (For further discussion, see the Methodology and Results sections of this report.) If the present testing is ineffective and the required testing is implemented, the battery unavailability may be reduced by a factor of 16. This could have a great impact on core melt frequency, exposure, and risk.

VIII-3.B dc Power System Bus Voltage Monitoring and Annunciation

The Millstone-1 control room has no indication of battery current or breaker/fuse status, battery charger current, or dc bus voltage or breaker/fuse status as required by 10 CFR 50.55a(h) and 10 CFR 50 Appendix A. Our analysis assumed that adequate weekly battery tests are performed (see issue VIII-3.A). Improved instrumentation reduces the unavailability of dc power since some faults can be detected immediately and repaired. The battery unavailability is reduced approximately 50 percent. The major contributor to dc unavailability at Millstone-1, however, is maintenance since the Technical Specifications allow operation for 1 week, 128 hours, with one battery out of service. We also reduced the maintenance unavailability by 50 percent to determine the effect of improved instrumentation with another reasonable improvement. Without a decrease in maintenance unavailability, the core melt frequency was reduced 0.6 percent, exposure by 0.4 percent, and risk by 0.3 percent from improved instrumentation. Adding a decrease in maintenance unavailability of 50 percent to the battery data, in addition to improved instrumentation, resulted in a decrease of 2.5 percent in core melt frequency, 1.5 percent in exposure, and 1.3 percent in risk.

IX-3 Station Service and Cooling Water Systems

A single failure in nonredundant pipe runs of the Service Water System and the Turbine Building Secondary Closed Cooling Water System could result in loss of system function. This is inconsistant with 10 CFR 50 Appendix A (GDC 44). Failures of pipe segments in these systems were analyzed in the IREP PRA and their contribution to the system failure rates was negligible. Failures of these systems which appeared in the dominant accident sequences had probabilities of approximately 10^{-3}. Pipe segment failure probabilities are about 10^{-9}. Thus, resolution of this issue has no effect on core melt frequency, exposure, or risk.

IX-5 Ventilation Systems

There are two areas of concern. First, the Standby Gas Treatment System would not always direct flow from areas of low radioactivity to areas of high radioactivity to limit the spread of radioactive material. Second, ventilation for safety-related equipment may be inadequate or unreliable. Since no release of radioactive material is identified in the first concern, it has no effect on risk. The IREP PRA considered failure of safety systems due to inadequate (or failure of) ventilation and did not identify any systems where ventilation was a concern. Thus, this issue has no effect on core melt frequency, exposure, or risk.

XV-1 Decrease in Feedwater Temperature, Increase in Feedwater Flow and Increase in Steam Flow

Failure of the feedwater controller to maximum demand results in an increase in reactor power and vessel inventory. This event would be more severe with the turbine bypass system unavailable. Limitations to either reactor power or minimum critical power ratio would be required in the Technical Specifications for the case where the turbine bypass is found to be inoperable. This is required by 10 CFR Part 50 Appendix A (GDCs 10 and 15). The risk significance of this issue is that if the turbine bypass is inoperable, any transient will occur with the power conversion system (PCS) unavailable as a mitigating system. This cause of unavailability of the PCS was analyzed in the IREP PRA and it was found to be negligible. That is, the historical rate of turbine bypass failure has been small enough compared to other causes of loss of the PCS that even if limitations on reactor operation with the turbine bypass unavailable prevented transients under that condition, the effect on the overall transient rate with loss of the PCS would be negligible. Thus, this issue has no effect on core melt frequency, exposure, or risk.

XV-3 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)

The maximum MCPR (minimum critical power ratio) should be calculated with an initial power level of 102 percent instead of 100 percent to meet the 10 CFR Part 50 (GDC 10, 15) requirement that the plant respond to loss of external load without exceeding the criteria regarding fuel damage and system pressure. PRAs calculate public risk from core melt accidents, which dominate the risk over low consequence events. This issue does not effect any core melt sequences and thus has no effect on core melt frequency, exposure, or risk.

XV-18 Radiological Consequences of Main Steam Line Failure Outside Containment

This issue addresses exceeding the 10 CFR Part 100.11 thyroid dose at the exclusion area boundary due to a main steam line failure (a non-core-melt event). PRAs calculate public risk from core melt accidents, which dominate the risk over low consequence events. This issue does not affect any core melt sequences and thus has no effect on core melt frequency, exposure, or risk.

I. Introduction

This report will present and discuss an analysis of the Systematic Evaluation Program (SEP) issues for the Millstone Point Unit 1 nuclear power plant. We have calculated the changes in core melt frequency and risk from resolution of the SEP issues which were within the scope of the Interim Reliability Evaluation Program (IREP) Millstone-1 Probabilistic Risk Assessment (PRA)[1]. This IREP study was modified to represent resolution of each issue and the resulting change in core melt frequency was calculated. These changes in core melt frequency were weighted by consequences to determine the effects on risk.

Because we have recalculated the values of the dominant sequences from the IREP Millstone-1 PRA, we report first a summary of the results of that PRA in section II. Section III presents the methodology we have used to calculate changes in sequence frequencies and risk. Section IV presents the results of our analysis and Section V gives the details of the analysis performed for each issue.

II. Summary of the Millstone-1 IREP PRA

The Interim Reliability Evaluation Program (IREP) Probabilistic Risk Assessment (PRA) performed for the Millstone-1 nuclear power plant did not attempt to analyze accidents resulting from fires, floods, hurricanes or other "external" events. The scope of the analysis was limited to transients and loss of coolant accidents followed by random failures of systems and components, test and maintenance outages, and operator errors. The methodology used was generally the same as developed for the Reactor Safety Study.[2] The result of the IREP study was a set of accident sequences (or scenarios), all of which result in core melt but, due to the timing of the core melt and the availability of various mitigating systems, may have different consequences. Associated with each sequence is the expected frequency of that specific accident. In this section, we will first discuss the core melt sequences and then the measures of release of radioactivity and consequences for the sequences.

The total expected frequency of core melt for Millstone-1 is 3×10^{-4}/Reactor-year. This frequency was dominated by twelve "dominant" sequences which contributed greater than 90 percent to the total core melt frequency. These sequences are given in Table 1. In addition, one non-dominant sequence, (SB) B, is included because it was used to analyze issue V-5. An explanation of each of the symbols used in the sequence names is given in Table 2. Note that the core melt frequency for Millstone-1 is dominated by transients from loss of normal ac power. Also, some sequences involve failure of the operator to depressurize the reactor coolant system and many sequences involve operator recovery actions to prevent core melt (the latter reduce the sequence frequencies).

The sequence frequencies were calculated by constructing fault trees for the system failures (and sucesses) represented in the sequence, linking the system successes and failures with AND logic and solving the resulting logic for the minimal cut sets. These cut sets represent unique sets of basic events (e.g., component failures) which result in the core melt sequence being analyzed. The frequency of the sequence is the sum of the frequencies of the cut sets, which are calculated from the failure data for the basic events.

The accident sequences result in releases of radioactivity to the environment which cause consequences, i.e., early and latent cancer induced fatalities. The releases were grouped into four release categories. A release placed in a given category would have similar consequences as other releases placed in that category. The release category assignments for each sequence were determined by the timing of the core melt, the mitigating systems operating, and the containment failure mode. Table 3 gives the release category assignments for the 12 dominant accident sequences. The frequency of release of a given sequence in a given release category is found by multiplying the sequence core melt frequency by the relative probability of release in the category of interest. The risk due to each sequence is found by multiplying its frequency of release in each category by the consequences of release in that category and summing over all release categories. The total plant risk is found by summing the risk of each sequence over all sequences.

Table 1
Dominant Millstone-1 Core Melt Sequences

Sequence	Expected Frequency (per Reactor-year)
T_4 JCD	7×10^{-5}
T_4 JCEFG	4×10^{-5}
T_4 KCEFG	3×10^{-5}
T_4 KCD	3×10^{-5}
T_4 LCD	3×10^{-5}
T_2 A	2×10^{-5}
T_4JCDG	2×10^{-5}
T_4JCMG	1×10^{-5}
T_4LCEFG	1×10^{-5}
T_4LCMG	1×10^{-5}
T_4KCDG	1×10^{-5}
T_4KCMG	9×10^{-6}
(SB) B*	3×10^{-6}

*"Nondominant" sequence.

Table 2
Symbols Used in Millstone-1 Core Melt Sequences

Symbol	Meaning
T_2	Loss of Power Conversion System Transient
T_4	Loss of Normal ac Transient
SB	Small Break LOCA
A	Failure of the Reactor Protection System
B	Failure of the Vapor Suppression System
C	Failure of the Feedwater Coolant Injection System
D	Operator Fails to Manually Depressurize the Reactor Coolant System
E	Failure of the Low Pressure Injection System
F	Failure of the Core Spray System
G	Failure of Containment Cooling
J	Safety/Relief Valve Fails to Reseat
K	Failure of the Isolation Condenser
L	Failure of Isolation Condenser Makeup
M	Failure of the Shutdown Cooling System

Table 3
Millstone-1 Accident Sequence Release Category Assignments

Sequence	Relative Probability of Sequence Causing Release in Category:			
	1	2	3	4
T_4JCD	10^{-4}	--	0.10	0.90
T_4JCEFG	10^{-2}	--	0.10	0.89
KC T_4~~JC~~EFG	10^{-2}	--	0.10	0.89
T_4KCD	10^{-4}	--	0.10	0.90
T_4LCD	10^{-4}	--	0.10	0.90
T_2A	10^{-4}	0.10	0.90	--
T_4JCDG	10^{-4}	--	0.10	0.90
T_4JCMG	10^{-2}	0.10	0.89	--
T_4LCEFG	10^{-2}	--	0.10	0.89
T_4LCMG	10^{-2}	0.10	0.89	--
T_4KCDG	10^{-4}	--	0.10	0.90
T_4KCMG	10^{-2}	0.10	0.89	--
(SB) B	10^{-4}	0.10	0.90	--

III. Methodology

The purpose of the analysis performed on the Millstone-1 SEP issues was to deduce the change in the core melt frequency and risk, as calculated by the IREP Millstone-1 study, from resolution of each issue. Some issues were outside the scope of the IREP analysis and, therefore, outside the scope of this analysis.

The remaining issues fell into three categories. These categories, also described in Table 4, were "data issues," "modeling issues," and "broad issues." Data issues were issues which affected the IREP PRA at the basic event level (e.g., bypassing thermal overload trips on valves). These issues required only changes in data for the PRA and, since the unavailabilities for components were being reduced, no new cut set solutions were required to evaluate the effect of the issues. The effect was to change the quantification of the cut sets in which the reduced data appeared.

Modeling issues were those which required redesign of a system to resolve the issue. Thus new system fault trees were required as well as data changes. It was necessary to re-solve for the minimal cut sets of the dominant accident sequences to determine the effect of the issues.

Broad issues were those which addressed a concern which could be evaluated without detailed consideration of the IREP accident sequences. In general, these concerns were considered in performing the IREP analysis, but for various reasons were not modeled into those accident sequences. For some issues, we invented new accident sequences. In other cases, the issues could be shown to be of negligible importance by general arguments.

For these three categories, the methodology can be displayed in flowchart form. This is shown in Figure 1.

Risk measures were calculated by weighting the changes in accident sequence frequency by the probability of release in each release category and the consequences of a release in each category (both man-rem exposure and relative numbers of total fatalities). The relative probabilities of release were given in Section II (Table 3) and Table 5 gives the consequences of releases in each release category. The release categories are defined in Reactor Safety Study,[2] the exposures were calculated in NUREG-0933,[3] "Prioritization of Generic Safety Issues," and the relative numbers of total fatalities were derived from consequence calculations for a northeast river valley composite site.[4] The exposure calculations for NUREG-0933 were truncated at 50 miles from the site, so the exposures reported may be underestimated.

Table 4.
Categories of Issue Analysis

Category	Description
Data	Issue affects only basic event data. New cut sets not required.
Modeling	Issue affects design of system and system fault tree. New cut sets were generated.
Broad	Issue not analyzed with IREP accident sequences. Assessment made on general arguments or invention of new sequences.

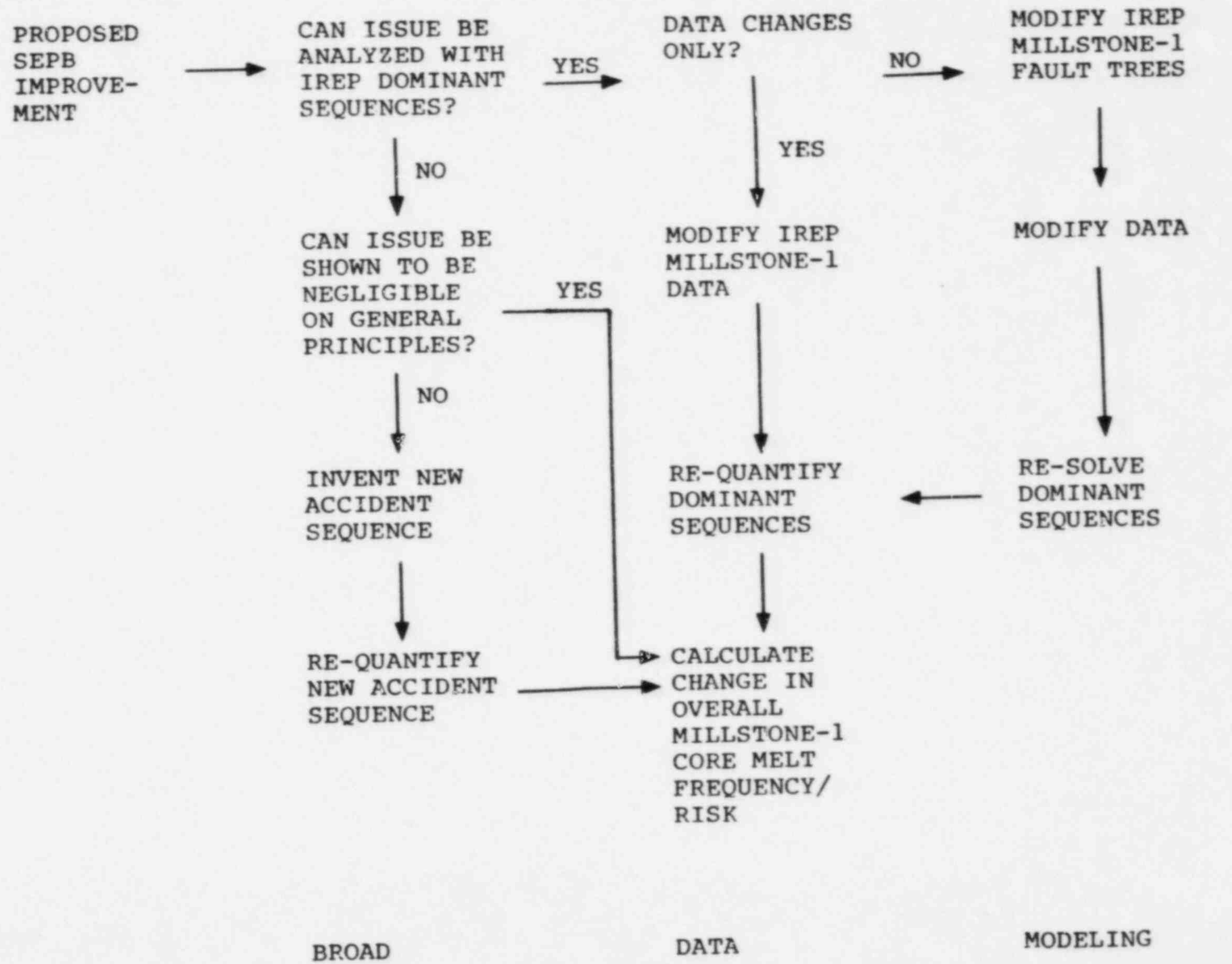


Figure 1. Flowchart for Analysis of Issues.

Table 5.
Consequences of a Release in Each Release Category

Release Category	Man-Rem Exposure	Relative Total Fatalities
BWR 1	5.4×10^6	0.51
BWR 2	7.1×10^6	0.32
BWR 3	5.1×10^6	0.16
BWR 4	6.1×10^5	0.009

III. Results

There were 40 issues identified by the SEP Branch for Millstone-1. Of these, 19 were outside the scope of the IREP Millstone-1 PRA and our analysis, and 21 were at least partially within this scope. Table 6 lists those issues outside our scope and Table 7 lists those issues which were within our scope and were analyzed.

As was described in the previous section of this report, our analysis of each issue fell into one of three categories. The classification of the issues according to the method of analysis is given in Table 8.

There were ten issues evaluated by requantifying the cut sets developed by the IREP PRA with new data, nine issues evaluated on general principles or quantifying accident sequences not developed in the PRA, and two issues evaluated by re-solving for the cut sets of the dominant accident sequences after changing the system fault trees to represent system design changes. The latter two issues are VI-7.C.1, which addresses the existence of automatic bus transfers of ac buses and manual transfers of dc load centers between redundant sources, and VII-3, which addresses the nonredundancy of instrument ac power.

These two issues are actually closely related. The requirement of redundancy of instrument ac cannot be met without first resolving issue VI-7.C.1 by providing redundant ac buses (without load transfers). For this reason, our analyses of issues VI-7.C.1 and VII-3 were performed together by making the system and system fault tree changes necessary to resolve both and re-solving for the frequencies of the dominant IREP Millstone-1 accident sequences. This is further justified by noting that the computing effort required to re-solve the dominant sequences even once was great. Most other issues were treated independently except VIII-3.B (adequacy of battery instrumentation) which assumed that adequate battery testing was implemented (issue VIII-3.A).

A final point is that, for both the "data" and "modeling" issues, our requantification of the dominant sequences was based on the assumption that the original Millstone-1 IREP PRA analysis was done correctly. This is especially important when interpreting our evaluation of issue VIII-3.A, the adequacy of battery testing. The concern is that the present battery testing may be, in the extreme, totally ineffective. The IREP PRA assessed that the present battery testing is at least somewhat effective. To <u>increase</u> the failure probability of the batteries by a large factor (to reassess the present situation) and calculate the effect would have required re-solving and rescreening thousands of accident sequences, a

Table 6.

Issues Not Analyzed (~~10~~ 19)

II-1.C

II-3.B

II-3.B.1

II-3.C

II-4.F

III-1

III-2

III-3.A

III-3.C

III-4.A

III-4.B

III-5.A

III-6

III-7.B

IV-2

V-6

V-12.A

VI-7.A.4

VIII-1.A

Table 7.

Issues Analyzed (21)

III-5.B

III-8.A

III-10.A

V-5

V-10.B

V-11.A

VI-4

VI-6

VI-7.A.3

VI-7.C.1

VI-10.A

VII-1.A

VII-3

VIII-2

VIII-3.A

VIII-3.B

IX-3

IX-5

XV-1

XV-3

XV-18

Table 8.

Classification of Issue Analysis

Data Issues

III-8.A

III-10.A

V-5

VI-7.A.3

VI-10.A

VII-1.A

VIII-2

VIII-3.A

VIII-3.B

IX-3

XV-1

Modeling Issues

VI-7.C.1

VII-3

Broad Issues

III-5.B

V-10.B

V-11.A

VI-4

VI-6

IX-5

XV-3

XV-18

computing effort at least as large as required to perform the original IREP analysis. Our methodology is based on the fact that for system changes that improve reliability, or for decreases in value of data, the effects can be quantified by considering only the original dominant sequences. Since the SEP issues address improving system reliability, and thus decreasing failure probabilities, this is generally valid. Because the IREP Millstone-1 PRA was used as the base case to compare our requantified sequences against, we assumed that the analysis contained in that study is correct.

Table 9 gives the decrease in core melt frequency, decrease in expected exposure, and ratio of risk (new/old) we calculated from the resolution of each issue. The executive summary of this report summarizes the analysis of each issue, and the next section presents the detailed analysis of each issue.

None of the calculated effects in Table 9 was greater than 15 percent. Because of the large uncertainties in the data used in the Millstone-1 PRA, none of the effects is at all significant compared to the overall uncertainty in the plant core melt frequency, exposure, and risk. The possible exception is issue VIII-3.A, battery testing, which we were unable to evaluate quantitatively.

Table 9.
Results of Analysis

Issue	Decrease in Core Melt Frequency(1) $(R\text{-}yr)^{-1}$	Decrease in Exposure (2) (man-rem/R-yr)	New Risk/Old Risk
III-5.B	(3)		
III-8.A	0.0	0.0	1.0
III-10.A	3×10^{-6}	3	0.996
V-5	3×10^{-6}	16	0.98
V-10.B	0.0	0.0	1.0
V-11.A	4×10^{-7}	3	0.991
VI-4	0.0	0.0	1.0
VI-6	0.0	0.0	1.0
VI-7.A.3	0.0	0.0	1.0
VI-7.C.1 } VII-3	3×10^{-5}	90	0.84
VI-10.A	0.0	0.0	1.0
VII-1.A	0.0	0.0	1.0
VIII-2	1×10^{-6}	3	0.995
VIII-3.A	(4)		
VIII-3.B	1.7×10^{-6}(5) 7.4×10^{-6}(6)	2(5) 8(6)	0.997(5) 0.987(6)
IX-3	0.0	0.0	1.0
IX-5	0.0	0.0	1.0
XV-1	0.0	0.0	1.0
XV-3	0.0	0.0	1.0
XV-18	0.0	0.0	1.0

(1) Total core melt frequency = 3×10^{-4}/reactor-year.
(2) Total expected exposure = 550 man-rem/reactor-year.
(3) Information to analyze this issue not received from utility.
(4) Issue could reduce battery unavailability, at most, by a factor of 16. Effect on risk outside scope of this analysis.
(5) Without decrease in maintenance unavailability.
(6) With decrease in maintenance unavailability.

References

1. A. A. Garcia, P. J. Amico, J. J. Curry, D. W. Gallagher, M. Modarres, and J. A. Radder, Interim Reliability Evaluation Program: Millstone Point Unit 1, to be published 1982.

2. Reactor Safety Study, WASH-1400 (NUREG-75/014), (1975).

3. Prioritization of Generic Safety Issues, NUREG-0933, to be published October 1982.

4. D. D. Carlson and J. W. Hickman, A Value-Impact Assessment of Alternate Containment Concepts, NUREG/CR-0165 (1978).

5. R. G. Spulak, Jr., P. J. Amico, and D. W. Gallagher, Risk-Based Categorization of Oyster Creek SEP Issues, to be published as Appendix D of the Oyster Creek SEP Integrated Assessment, 1982.

6. R. G. Spulak, Jr, P. J. Amico, and D. W. Gallagher, Risk-Based Categorization of Dresden-2 SEP Issues, to be published as Appendix D of the Dresden-2 SEP Integrated Assessment 1982.

IV Issue Analyses

Following are the analyses of each of the issues.

III-8.A Loose Parts Monitoring and Core Barrel Vibration Program

1. NRC Evaluation

A loose parts monitoring program as required by Regulatory Guide 1.133 does not exist at Millstone-1.

2. NRC Recommendations

Install a loose parts monitoring system to detect loose parts in the Reactor Coolant Pressure Boundary.

3. Systems Affected

Loose parts can cause transient events by causing damage within the reactor coolant system.

4. Comments

None.

5. Analysis

The only concern of loose parts from a risk perspective is that they may cause a transient which challenges the plant and its safety systems. There is ample data on transients to show that this effect is negligible. That is, because the historical transient rate is so high, several per reactor-year, and the contribution to that frequency by loose parts has been negligible, eliminating loose-parts-induced transients will have no effect on the transient frequency.

In the USNRC Memorandum from L. S. Rubenstein to S. Hanauer, Director, DST, and D. Eisenhut, Director, DL, May 6, 1982 on the Loose Parts Monitoring Program, a history of loose parts effects to 1977 is given. There were 46 "events" (loose parts), of which 23 were discovered by routine surveillance and 15 caused damage or malfunction. None of these "events" were transients requiring plant shutdown.

6. Conclusions

Eliminating loose-parts-induced transients by installing a loose parts monitoring system would have no effect on any IREP Millstone-1 accident sequences.

III-10.A Thermal Overload Protection for Motors of Motor-Operated Valves

1. NRC Evaluation

Thermal overload protection devices for MOVs should be bypassed under emergency conditions or the trip setpoint should be set at a value high enough to prevent spurious operation of the protection device. The thermal overload protection devices are not bypassed on 21 of the ECCS valves at the Millstone-1 plant.

2. NRC Recommendation

The design of the 12 MOVs that do not have thermal overload protection device bypasses and that are not normally in their emergency positions should be modified. The thermal overload protection devices should be bypassed when an emergency signal is present.

3. Systems Affected

The only systems that are affected and were modeled in the Millstone IREP study are the Service Water System and the Isolation Condenser Makeup System.

4. Comments

Spurious operation of the thermal overload protection device will add to the unavailability of the MOV. In bypassing this device the unavailability of the MOV is reduced. The effect of this change can be modeled by eliminating the contribution of the thermal overload protection devices to the unavailabilities used in the Millstone-1 IREP study and reevaluating the MOV contribution to the dominant accident sequences.

5. Analysis

The failure rate for an MOV (failure to open on demand) used in the Millstone IREP study was based on WASH-1400, The Reactor Safety Study. From Appendix III of that study, the failure rate, assuming monthly valve testing, for an MOV is

$$\lambda_D = 1 \times 10^{-3}/d.$$

This data is based on plant operating and test data. Since thermal overloads are not bypassed during tests, this valve failure rate includes the contribution of failures of these devices.

The failure rate for a typical thermal overload device can be found in Section 1 of Non-Electric Parts Reliability Data (NPRD-2).

The failure rate for a thermal relay is given as

$$\lambda_s = 4 \times 10^{-7}/\text{hr}.$$

This device would be tested monthly during the valve test. The unavailability of the MOV due to the contribution of this device would then be

$$\lambda_D = \overset{\frac{1}{2}}{\cancel{1/2}}\, \lambda_s T,$$

where T is 1 month (720 hrs). The contribution of the thermal overload device to the valve unavailability is 1.4×10^{-4}. Overriding this device would decrease the MOV unavailability from 1×10^{-3} to 8.6×10^{-4}. (This neglects any negative effect of bypassing the thermal overload protection.)

If the MOV and the thermal overload protection device are tested during refueling outages, the demand failure rate of the MOV is 1.7E-2 (this includes the failure of the thermal overload protection device which is 2.4E-3).* Bypassing the thermal overload protection device reduces the MOV demand failure rate to 1.5E-2.

Only two of the valves that do not have their thermal overload protection devices bypassed were modeled in the Millstone IREP study. Both valves are cycled at refueling. The two valves are 1-SW-9 (in the Service Water System) and 1-IC-10 (in the Isolation Condenser Makeup System).

The failure probabilities for these two valves were reduced from 1.7E-2 to 1.5E-2 and the dominant core melt sequences from the Millstone-1 IREP study were requantified. The results of this analysis are shown in Table III-10.A-1. The second column shows the contribution of cut sets containing the two MOV failures prior to the data change. The third column shows the contribution of cut sets containing the MOV failures after the data change. The total reduction in core melt frequency in the dominant accident sequences is 2.8E-6/Ryr.

6. Conclusion

Bypassing the thermal overload protection devices on the MOVs of concern makes a minor (<1 percent) change in the overall core melt frequency at Millstone-1. Although this reduction in a component unavailability affects half of the dominant sequences, the effect on each sequence is very small.

*The hourly failure rate for the MOV is derived from the equation $\frac{1}{2}$ $\lambda_D = \cancel{1/2}\, \lambda_s T$. The demand rate of 1×10^{-3} assumed monthly testing of the valve. The fuel cycle length for Millstone is approximately 12,000 hrs.

Table III-10.A-1
Effect of MOV Thermal Overload Protection Bypass

Dominant Sequence	Sequence Frequency*	Frequency* of Cut Sets With MOV Failure	Frequency* of Cut Sets With Reduced MOV Failure Rate	Sequence Frequency* Reduction
T_4JCD	6E-5	1.8E-6	1.6E-6	2E-7
T_4JCEFG	4E-5	2.6E-9	2.3E-9	3E-9
T_4KCD	3E-5	1.5E-6	1.3E-6	2E-7
T_4KCEFG	3E-5	--	--	--
T_4LCD	3E-5	2.07E-5	1.83E-5	2.4E-6
T_2A	2E-5	--	--	--
T_4JCDG	2E-5	2.1E-8	1.9E-8	2E-9
T_4JCMG	2E-5	--	--	--
T_4LCEFG	1E-5	--	--	--
T_4LCMG	1E-5	1.4E-8	1.2E-8	2E-9
T_4KCDG	1E-5	--	--	--
T_4KCMG	9E-6	--	--	--
Total	2.89E-4	2.4E-5	2.18E-5	2.8E-6

*Per Reactor Year

V-5 Reactor Coolant Pressure Boundary Leakage Detection

1. NRC Evaluation

The systems employed for the detection of leakage from the reactor coolant pressure boundary to containment do not meet the criteria of 10 CFR (GDC 2.30) because the instruments are not testable during normal operation, the systems do not have the required sensitivity, the Technical Specifications do not impose operability requirements, and some systems do not have the required seismic qualification.

2. NRC Recommendation

Modify or install leakage detection capability to meet the criteria, including the ability to detect 1 gallon per minute (gpm) leakage in 1 hour.

3. Systems Affected

This issue affects the frequency of small LOCAs.

4. Comments

The NRC hypothesis is that early leak detection may allow operator action to isolate the leak or shutdown (depressurize) the plant, thereby prevent the leak from becoming a LOCA. This is the "leak-before-break" issue for pipes.

There are several unknowns associated with assessing the impact of leak detection time on preventing LOCAs: the mean time it would take a leak to grow to LOCA proportions, the fraction of leaks which, in fact, become LOCAs, and the ability of the operators to prevent a LOCA upon discovering a small leak.

A parallel concern is that the leak (pipe crack) might not grow naturally, but if the plant experienced a transient before the leak was detected and the plant shutdown, the transient could cause the crack to become a break, i.e., a LOCA. We did not analyze this concern because of lack of data on these kinds of leaks. In addition, we did not consider the high energy pipe break (systems interaction) aspects of the breaks because PRAs do not assume any additional failures caused by LOCAs.

5. Analysis

Previous studies of this issue for BWRs similar to Millstone-1 (the "Risk-Based Categorization of "Oyster Creek..." and "...Dresden-2 SEP Issues" published in the SEP Integrated Assessments for those two plants) have shown that the small LOCA frequency is dominated by pipe breaks (not reactor recirculation pump seal failures). Assuming that all the pipe breaks used to generate the small LOCA data for the Millstone-1 IREP PRA (data from the Reactor Safety Study) began as leaks which grew to breaks, improved leakage detection could decrease the small LOCA frequency from the "usual" value of 1×10^{-3}/Ryr.

Because of the many unknowns (the effects of which were explored in the Oyster Creek and Dresden-2 analyses of this issue), we did not attempt to quantify the exact effect of improved leakage detection. Instead, we have shown the effect on core melt frequency and risk to be small even if the small LOCA frequency could be reduced to zero.

There were no dominant sequences identified in the Millstone-1 IREP PRA which were initiated by a small LOCA. In fact, there was only one small LOCA sequence analyzed in detail in the study because it was the only small LOCA sequence with a frequency greater than 1×10^{-6}/Ryr, the frequency below which sequences were truncated from the analysis. This sequence was (SB)B with a frequency of 3×10^{-6}/Ryr.

Thus, even if improved leakage detection could totally eliminate small LOCAs, the maximum effect would be to decrease the core melt frequency by 3×10^{-6}/Ryr, or 1 percent.

6. Conclusion

Eliminating all LOCAs with improved leakage detection would decrease the core melt frequency by 3×10^{-6}, or 1 percent.

V-10.B RHR Reliability

1. NRC Evaluation

The Millstone-1 shutdown systems were compared to the criteria of SRP 5.4.7 and BTP RSB 5-1. The following are areas where Millstone-1 does not comply with these criteria: 1. The operating/emergency procedures for Millstone-1 do not use only safety grade systems for conducting plant shutdown and cooldown. (These procedures include use of the shutdown cooling system, which is not considered to be a safety grade system.) 2. No procedure exists to perform a cooldown to cold shutdown from outside the control room.

2. NRC Recommendations

Two recommendations are made. First, the licensee should develop plant operating/emergency procedures for conducting a plant shutdown and cooldown using only safety grade systems and equipment. Second, the licensee should develop procedures for conducting a plant cooldown to cold shutdown conditions from outside the control room.

3. Systems Affected

The following systems are the Millstone-1 saety grade systems that the recommended procedures would utilize:

Reactor Control and Protection System
Automatic Pressure Relief Systems
Feedwater Coolant Injection System
Service Water System
Low Pressure Coolant Injection/Containment Cooling System
Emergency Service Water System
Emergency AC Power Systems
DC Power System

The additional systems now referenced in the Millstone-1 operating/emergency procedures are the Isolation Condenser System and the Shutdown Cooling System.

4. Comments

It is important to note that this issue deals with the failure of the procedures to use only safety grade systems for shutdown, not that the procedures do not reference these systems. All of the safety grade systems are used by the Millstone-1 operating/emergency procedures.

The issue of not having procedures for reaching cold shutdown from outside the control room addresses the broad issue of how important it is to core melt frequency and risk and go from hot shutdown to cold shutdown. PRA studies to date including WASH 1400 and the Millstone-1 IREP study have assumed that the dominant part of the risk is from failing to achieve hot shutdown. These studies, in examining only the accident scenarios where there is a failure to reach hot shutdown, have examined the major contributors to the risk due to core melt.

5. Analysis

In examining the procedures for achieving hot shutdown, a PRA will take into consideration all possible means by which an operator could be expected to reach hot shutdown. This would include methods using only safety grade systems and systems that are not safety grade provided their use can be justified. Justification is usually automatic system operation or a written procedure that details the use of the system. The potential lower reliability of a nonsafety grade system (as opposed to a safety system) would be evaluated on a system-by-system basis.

Through the use of the normal operating and emergency procedures in use at Millstone-1 now, the operators have the option to use any of the systems at their disposal, safety and nonsafety grade, to reach hot shutdown. Included in this are the system combinations that would use only safety grade systems. Additionally, the operator can use, by procedure, several combinations of safety and nonsafety systems. By restricting the operator to the use of safety grade systems only, the number of successful system combinations the operator can use to reach hot shutdown is reduced. Although the nonsafety grade systems may not be as reliable as the safety grade systems, their presence and the operators' ability to use them does add some redundant capabilities. Removing the nonsafety systems from the shutdown procedures would eliminate that redundancy.

6. Conclusion

The ability to use both safety grade and nonsafety grade systems in shutting down the Millstone-1 plant provides redundant shutdown capabilities beyond those of the safety grade systems alone. The use of a procedure using only safety grade systems would not yield a reduction in the risk due to core melt.

The need to get from hot shutdown to cold shutdown is generally not addressed as significant to risk. Therefore, the existence or lack of existence of procedures to achieve cold shutdown from outside the control room would have no effect on the risk due to core melt.

V-II.A Requirements for Isolation of High and Low Pressure Systems

1. NRC Evaluation

The reactor water cleanup system does not meet current licensing criteria for the isolation of this system from the reactor coolant system. The redundant isolation valves on the suction line of the reactor water cleanup system receive their isolation signal from the same pressure sensor.

2. NRC Recommendation

Independent interlocks should be installed on the inboard suction isolation valve of the reactor water cleanup system.

3. Systems Affected

The reactor water cleanup system and reactor coolant system (through an interfacing system LOCA) are the systems affected.

4. Comments

This possible cause of an interfacing system LOCA was not included as part of the Millstone IREP study. Although the consequences are severe, the probability of this event was deemed to be too low to make a contribution to the risk due to core melt. This does not preclude this event from being important as a potential souce of radioactive release. An interfacing system LOCA would be a release (after core melt) in BWR release category 2.

5. Analysis

The suction line of the reactor water cleanup system is shown in Figure V-11.A-1 and the fault tree for the failure to isolate on high pressure is shown in Figure V-11.A-2. The two motor-operated isolation valves and the pressure control valve all operate on a single signal from one pressure sensor. (The isolation valves also close on other conditions: low flow, high temperature, etc. However, the pressure signal is the only signal of interest for this analysis.) In Figure V-11.A-1, only the equipment that can be used to isolate the reactor water cleanup system is shown.

No credit is taken for any operator action tht would stop the high pressure leak into the reactor water cleanup system. Although the operator would eventually isolate the system if the automatic isolation devices failed, an interfacting system LOCA would already have occurred. The operator actions would reduce the consequences but not eliminate them and, therefore, no credit is taken for operator actions.

The failure of the high pressure interlock is dominated by the failure of the pressure sensor (failing valves 1201-2, 1201-5, and 1217) and failure of the pressure relief valve, 1201-36. The frequency of failure of the high pressure interlock system is 3.8E-7/Ryr. (Data for this analysis is shown in Table V-11.A-1.)

Frequency = F(sensor 1291-14 fails) x P(relief valve 1201-36 fails) + P(MOV 1201-2 fails to close) x P (MOV 1201-5 fails to close) x F(pressure control valve 1217 fails) x P(relief valve 1201-36 fails)
= 2.4E-3/Ryr x 1.6E-4 + 1.6E-2 X 7E-4/Ryr X 1.6E-4
= 3.8E-7/Ryr

A modified design for the high pressure interlock would utilize a second pressure sensor to control one of the two isolation valves. A modified fault tree for this system arrangement is shown in Figure V-11.A-2. From this fault tree the frequency of a high pressure interlock failure in the reactor water cleanup system is 6.8E-9/Ryr.

Frequency = [P(MOV 1201-2 fails) + P (sensor 1201-36A fails)] X [F(sensor 1201-36 fails) + P (MOV 1201-5 fails) X F(PCV 1217 fails)] X P(relief valve 1201-36 fails)
= (1.6E-2 + 1.6E-3)(2.4E-3/R-yr + (1.6E-2)(7E-4/Ryr))(1.6E-4)
= 6.8E-9/Ryr

In both system configurations analyzed it is assumed that a failure of the high pressure interlock system will inevitably lead to an interfacing system LOCA. Therefore the frequency of high pressure interlock failures determined above is the interfacing system LOCA frequencies for both reactor water cleanup system designs.

When the pressure sensor fails to properly control the pressure in the RWCU system suction line and the relief valve functions properly, a large LOCA occurs. Using the relatively conservative assumptions of this analysis, this event has a frequency of approximately 2 x 10^{-3}/Ryr. This is approximately an order of magnitude larger than the frequency used in the Millstone IREP study. However, even when the frequency of the large LOCA is increased by a factor of 10, none of the large (S_1) LOCA initiated sequences appear as a dominant core melt sequence. An examination of the sequences initiated by an S_1 LOCA would have a frequency on the order of 10^{-7}/Ryr.

6. Conclusion

The proposed change in the interlocks for the reactor water cleanup system reduces the frequency of LOCAs in the reactor water cleanup system by almost two orders of magnitude. The system as it is now designed has a failure frequency of only 4E-7/Ryr. When compared to the expected core melt frequency of approximately 3×10^{-4} the contribution to the overall plant risk of this interfacing sytem LOCA is small.

Table V-11.A-1
Data Summary

	Failure Rate (hr^{-1})	Exposure Time	Frequency/ Unavailability
MOV failure to close	2.7E-6	8 months*	1.6E-2
Pressure sensor failure	2.7E-7	8 months	1.6E-3
-- frequency	2.7E-7	1 yr	2.4E-3/Ryr
Pressure Control Valve-- fails to open	2.7E-6	1 yr	2.4E-2/Ryr
Pressure relief valve-- fails to open	2.7E-8	8 months	1.6E-4

*Millstone-1 has a 16-month fuel cycle.

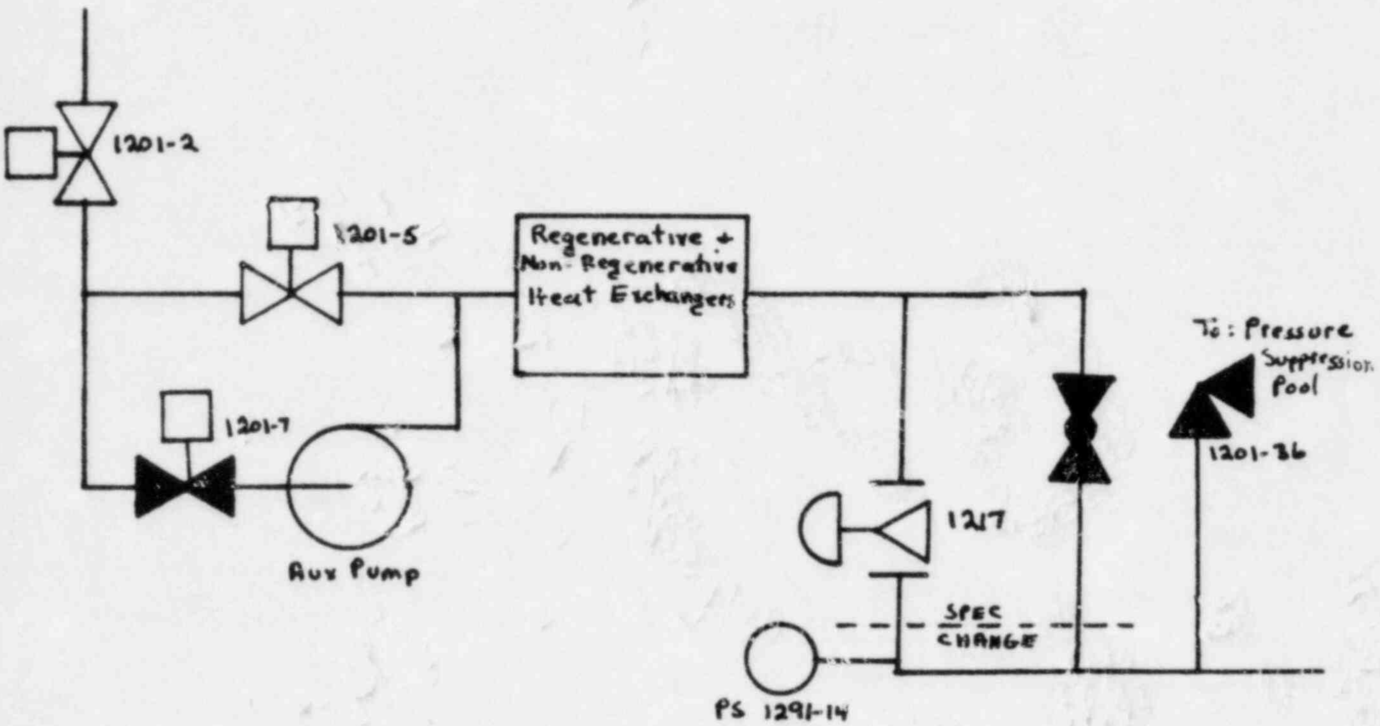


Figure V-11.A-1 Reactor Water Cleanup System: Suction Line High Pressure Section.

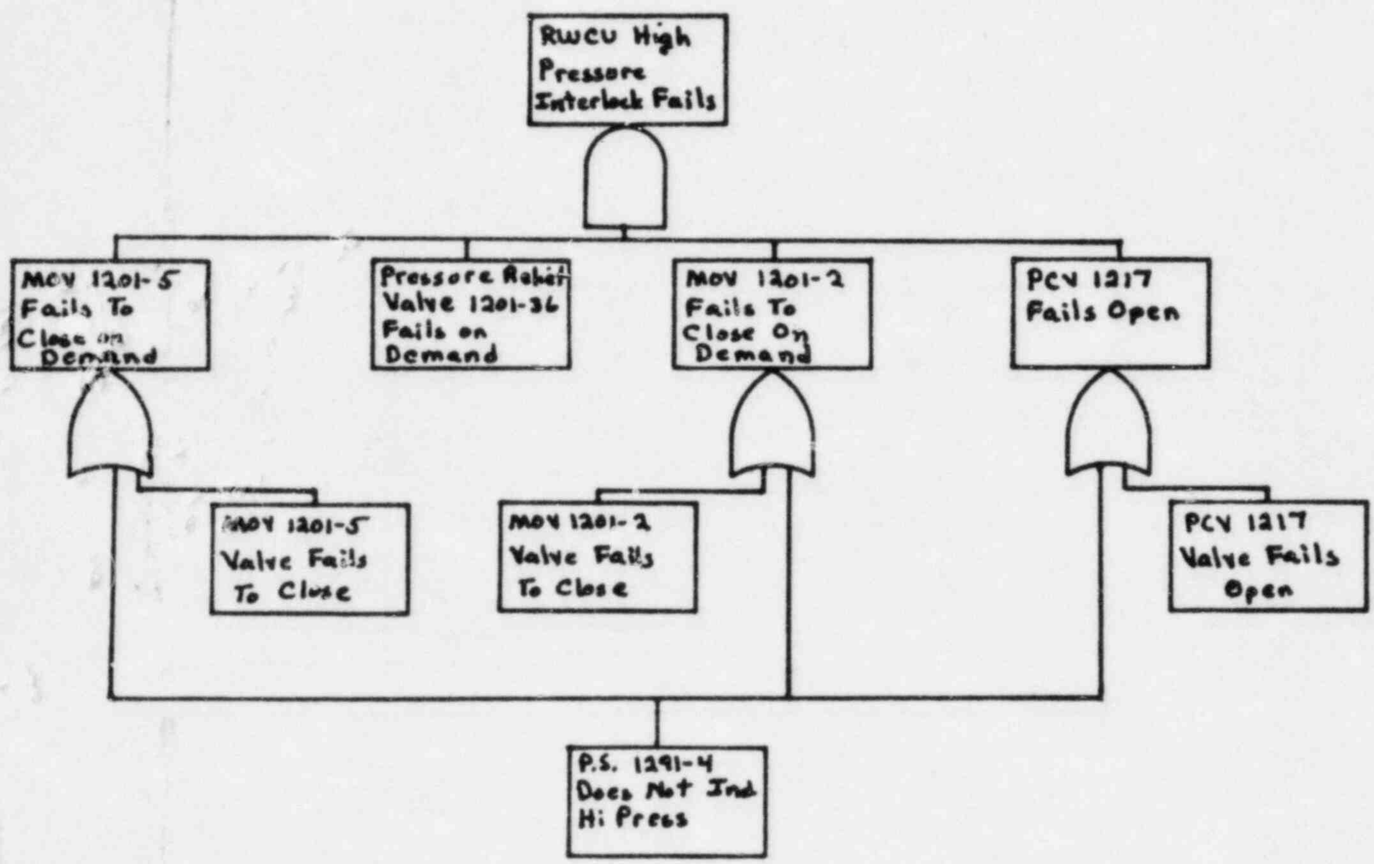


Figure-11.A-2 Interlock System Fault Tree.

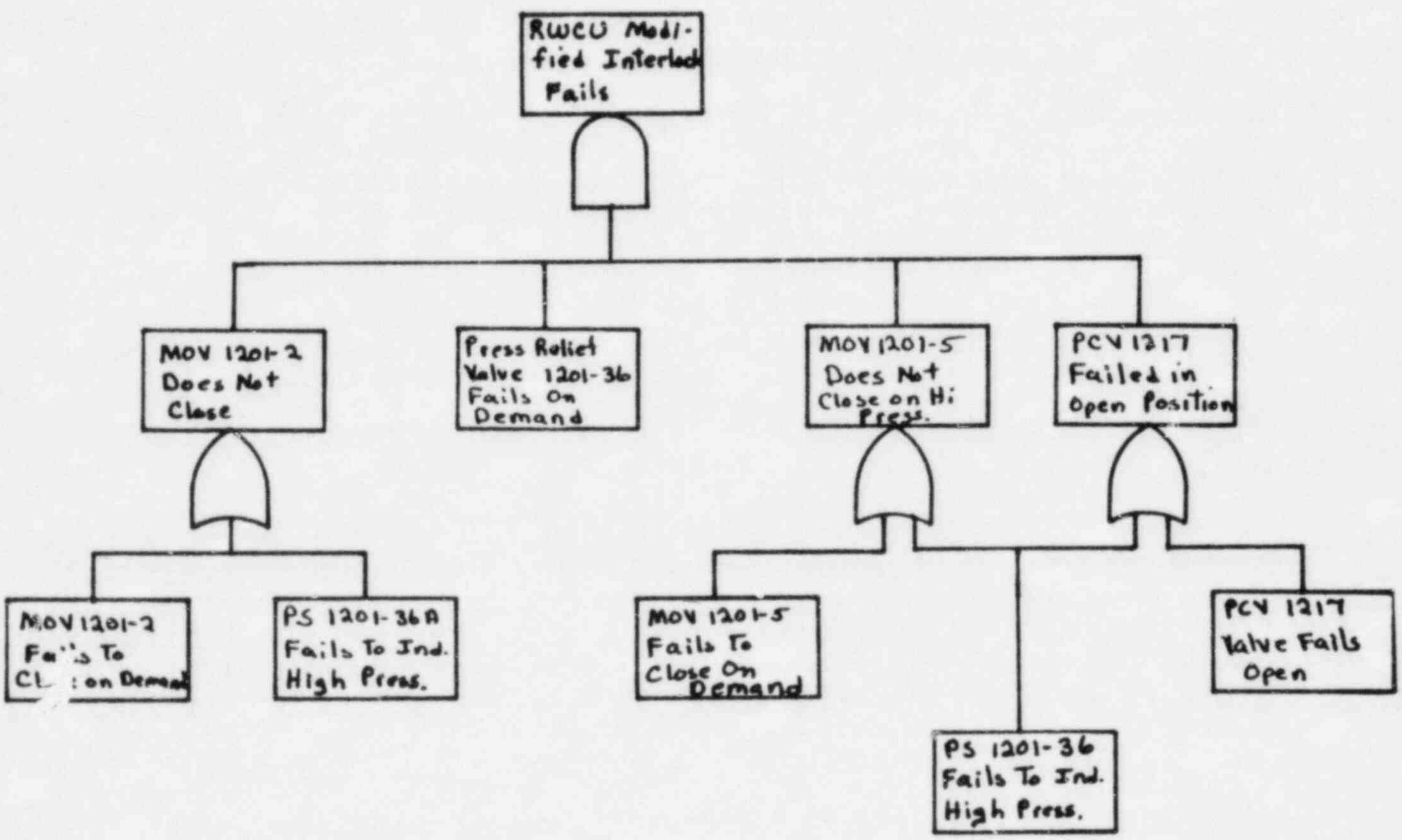


Figure V-11.A-2 RWCU System Modified Interlock Fault Tree.

VI-4 Containment Isolation System
VI-6 Leak Testing

1. NRC Evaluation

Both of these issues address the adequacy of containment integrity during accident conditions. Issue VI-4 identifies many containment penetrations which could have high probabilities of failure to isolate and Issue VI-6 identifies a request by the licensee to perform Type A leak tests for durations less than 24 hours.

2. NRC Recommendations

Backfit the necessary hardware and testing to make the containment penetrations conform to the GDCs and ensure containment integrity during accident conditions.

3. Systems Affected

These issues affect the nature of the release of radioactive material in an accident and thus the consequences of the accident.

4. Comments

We will not analyze each penetration here, but will show that the whole issue of containment isolation is not important at Millstone-1.

5. Analysis

Because of the small size and (relatively) low design pressure of the Millstone-1 containment, the pressure generated by steam and noncondensible gases during a core melt accident will certainly fail the containment if another failure mechanism does not occur first. In the IREP PRA, all the accident sequences fail the containment by overpressure if a steam explosion does not occur. The probability of containment isolation failure was small enough that it was negligible.

The effect of changing the effectiveness of isolation of the penetrations is to shift the containment failure mode between leakage through the failed penetration and overpressure rupture (if leakage would be great enough to prevent rupture). The overpressure failures for the Reactor Safety Study Peach Bottom, Reactor Safety Study Methodology Applications Program Grand Gulf, IREP Brown's Ferry, and IREP Millstone-1 PRAs were BWR Release Category 2 and 3 releases. Containment leakages (failure to isolate penetrations) were Release Category 4 releases in these studies. The smaller numbered release categories result in higher consequences. Thus improving the isolation could only decrease the Category 4 releases and increase the higher consequences Categories 2 and 3 releases.

6. Conclusion

Because the Millstone-1 containment will fail by overpressure in a core melt accident if no other failure occurs first, improving containment isolation will not decrease the probability of release during such an accident or lower the consequences of the release.

VI-7A.3 ECCS Actuation System

1. NRC Evaluation

It is required that all ECCS components be included in the component and systems tests and that the scope of the periodic testing is adequate. It was found in the review for Millstone-1 that the core spray pump spare coolers are not tested and that the testing of the LPCI system is inadequate because the tests do not demonstrate that the Emergency Service Water (ESW) System will be actuated with the LPCI system.

2. NRC Recommendations

The licensee must develop suitable changes to the technical specifications to ensure that the proper testing is performed.

3. Systems Affected

The core spray and LPCI/ESW systems are affected by this issue.

4. Comments

This issue encompasses two distinct deviations. The first is the testing of the core spray pump spare coolers. The question of the need for space cooling was treated in the Millstone-1 Interim Reliability Evaluation Program (IREP) study. The study determined that space cooling was not required for the core spray pumps to perform their function. This was substantiated by the results of tests performed by General Electric on April 23, 1970 and documented in GE Letter MS-2320, May 2, 1970, on the subject of "Emergency Core Cooling System Corner Room Heatup Test." The document stated that the ECCS pumps were operated under accident conditions continuously for 36 hours without space cooling. The summary of results for the core spray pumps are as follows:

Location	Maximum Allowable Temperature	Actual Maximum Temperature During Test
Room ambient	165°F	90°F
Pump motor outlet	220°F	128°F

It is obvious that the pump was never in danger of overheating. Since space cooling is not required for core spray system success, any improvement in space cooling provided by testing will not improve overall system reliability. No further analysis of this deviation is required.

The second deviation is the need for a test ensuring that the ESW system is actuated with the LPCI system. It is not possible to have a test of this type since the ESW system is designed to be manually actuated by the operator at some time after an accident. It is not designed to start automatically along with LPCI, and is not required for LPCI to perform its initial ECCS function. ESW is actuated at a later time to provide containment cooling. It was decided to evaluate the effect on risk if the ESW system did have automatic actuation with LPCI.

5. Analysis

The results of the Millstone-1 IREP study were reanalyzed based on a redesign of the ESW system to support automatic actuation. It was assumed that the logic would be modified to actuate ESW using spare contact pairs of the same relays which actuate LPCI. The only effect this would have would be to eliminate operator error in starting ESW from the possible ways of failing the system. All other failure mechanisms would remain. It was determined by the reanalysis that operator errors in initiating ESW did not contribute to any dominant sequences, thus eliminating them by automatic actuation would not reduce any sequence frequency.

6. Conclusion

Based on the evaluation of this issue using the Millstone-1 IREP study, it was found that testing of core spray pump space cooling does not reduce system unavailability since it is not required for core spray system success. In addition the ESW cannot be tested for actuation with LPCI since it is not designed to operate automatically. However, even if ESW were redesigned to actuate automatically, testing would not reduce any sequence frequencies.

VI-7.C.1 Independence of Redundant Onsite Power Systems

1. NRC Evaluation

The purpose of this NRC review was to determine if any conditions can exist which would result in paralleling redundant power sources. This includes the possibility of transferring faults from one power train to another, thus failing both. At Millstone-1, motor control centers 2-3NE, 2A-3NE, and 22A-1, as well as the 120 V ac instrument bus, have automatic bus transfers (ABTs) which can transfer loads between redundant sources. The dc system has three load centers which can be manually transferred between redundant sources, with no interlocks to prevent an operator error that would parallel the dc buses to a single emergency source.

2. NRC Recommendation

The licensee must remove or justify the ABTs and provide suitable interlocks for the dc transfers.

3. Systems Affected

The systems affected by this issue are the emergency ac power system and the dc power system.

4. Comments

The bus nomenclature used in the NRC Evaluation bus not been used at Millstone-1 for some time. This analysis will use the current nomenclature as illustrated in the drawings in this section and used in the Millstone-1 IREP study. Since the NRC recommendation did not specify a particular design change, other than removal of the bus transfer devices, we have developed our own redesign of the system to address this issue. We do not claim that this is either the best or the only way to accomplish the goal, but simply is a sensible and logical design alternative.

5. Analysis

The present design of the ac and dc systems is shown in Figures VI-7.C.1-1a through VI-7.C.1-1d. They show automatic bus transfer devices on ac motor control centers EF3, FE3, EF7 and CD6 and on the Instrument ac (IAC) and Vital ac (VAC) buses, as well as manual transfers on dc motor control centers 101AB-1, 101AB-2, and 101AB-3. The ABT on the Vital ac bus does not actually transfer loads between redundant power sources since the M/G set acts as an isolation device. However, it was felt necessary to include this in the redesign for other reasons related to the need to redesign the Instrument ac (see issue VII-3). The changes for ac MCCs EF3, FE3, EF7 and CD6 simply involved removing the ABTs and hard wiring the buses directly to a power source. This is shown on Figures VI-7.C1-2a and VI-7.C.1-2b. Similarly, for the dc MCCs AB-1, AB-2, and AB-3, the manual bus transfers were removed as shown in Figure VI-7.C.1-2d. The redesign for the IAC and VAC buses were more complicated. This is because these buses do not supply redundant load groups. That is, they each supply needed service to the whole plant (this aspect is treated in issue VII-3). Thus, in order to remove the ABTs and therefore connect the bus to a particular power source, it becomes necessary to split the loads on these buses in half according to the associated equipment train which they affect. This resulted in a redesign which created separate IAC and VAC buses for each train. This is shown on Figure VI-7.C.1-2c. A further complication was that in the case of the control logic for the shut-down cooling system, only one logic train existed, as shown in Figure VI-7.C.1-3. This required the creation of a new control logic design which had two trains, one to be associated with each new IAC bus. This is shown on Figure VI-7.C.1-4 sheets 1 + 2. All these modifications were evaluated by changing the fault trees from the Millstone-1 Interim Reliability Evaluation Program (IREP) Study to represent the modified electrical power systems design discussed above, and then requantifying the dominant event tree sequences to determine if any risk reduction was realized.

Since the modifications for this issue were inseparable from the modifications for issue VII-3, these two issues were requantified together. The results are reported in the discussion of the analysis of issue VII-3, which see.

6. Conclusions

Resolution of issues VI-7.C.1 and VII-3 would reduce core melt frequency by 10 percent.

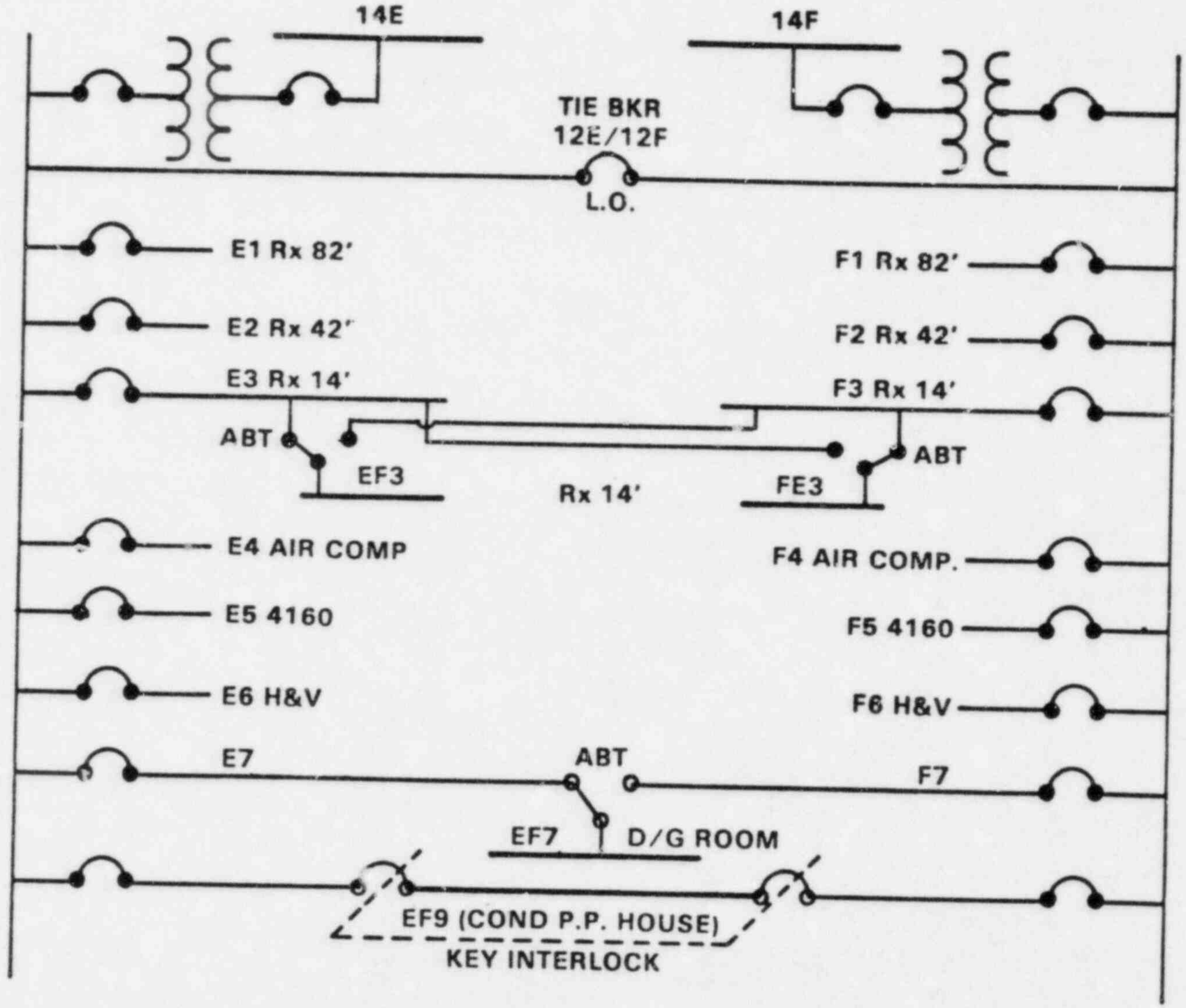


Figure VI-7.C.1.-1a. 480 Volt Distribution 12E-12F Bus Before

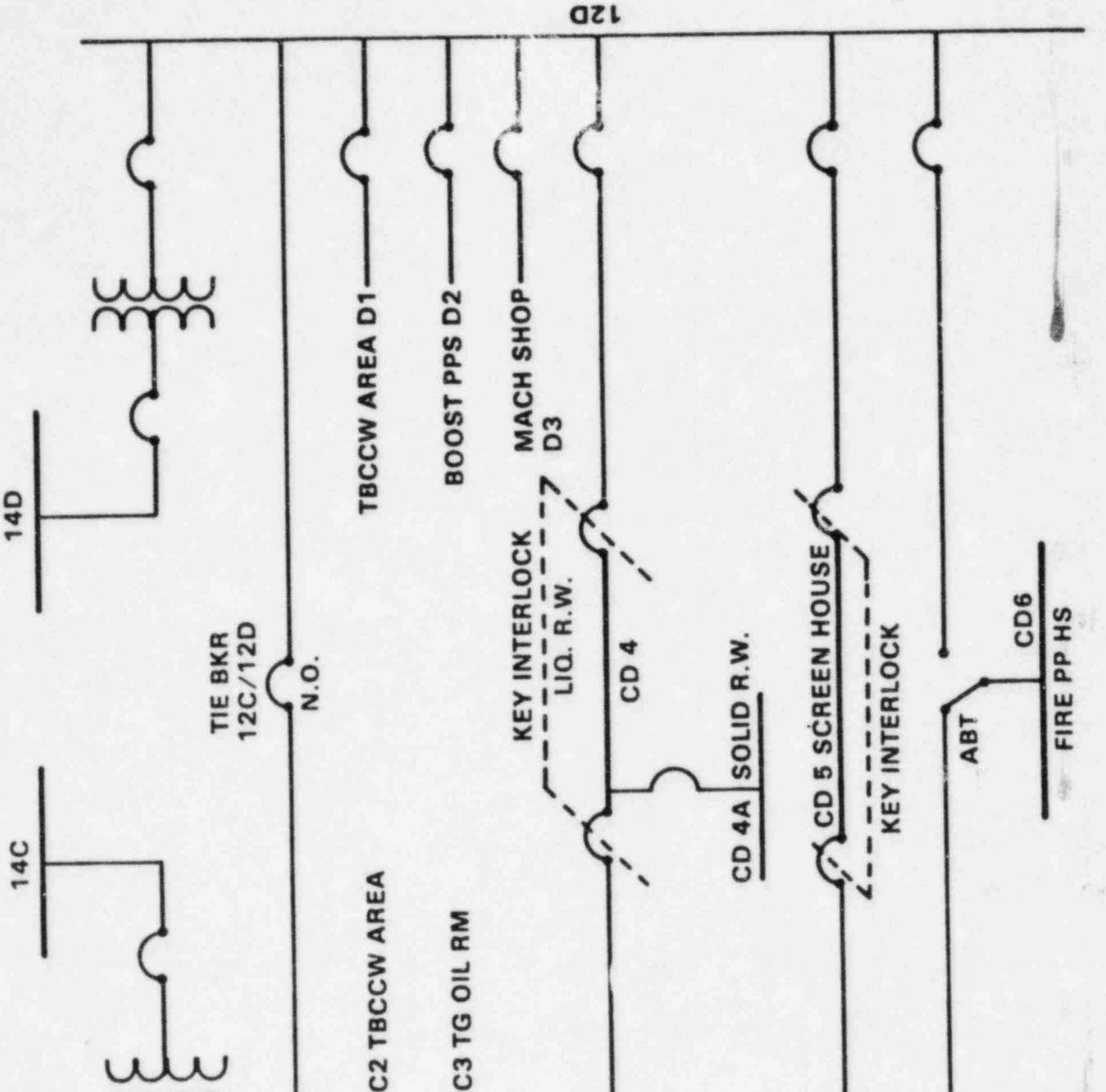


Figure VI-7.C.1.-1b. 480 Volt Distribution 12C-12D Bus Before

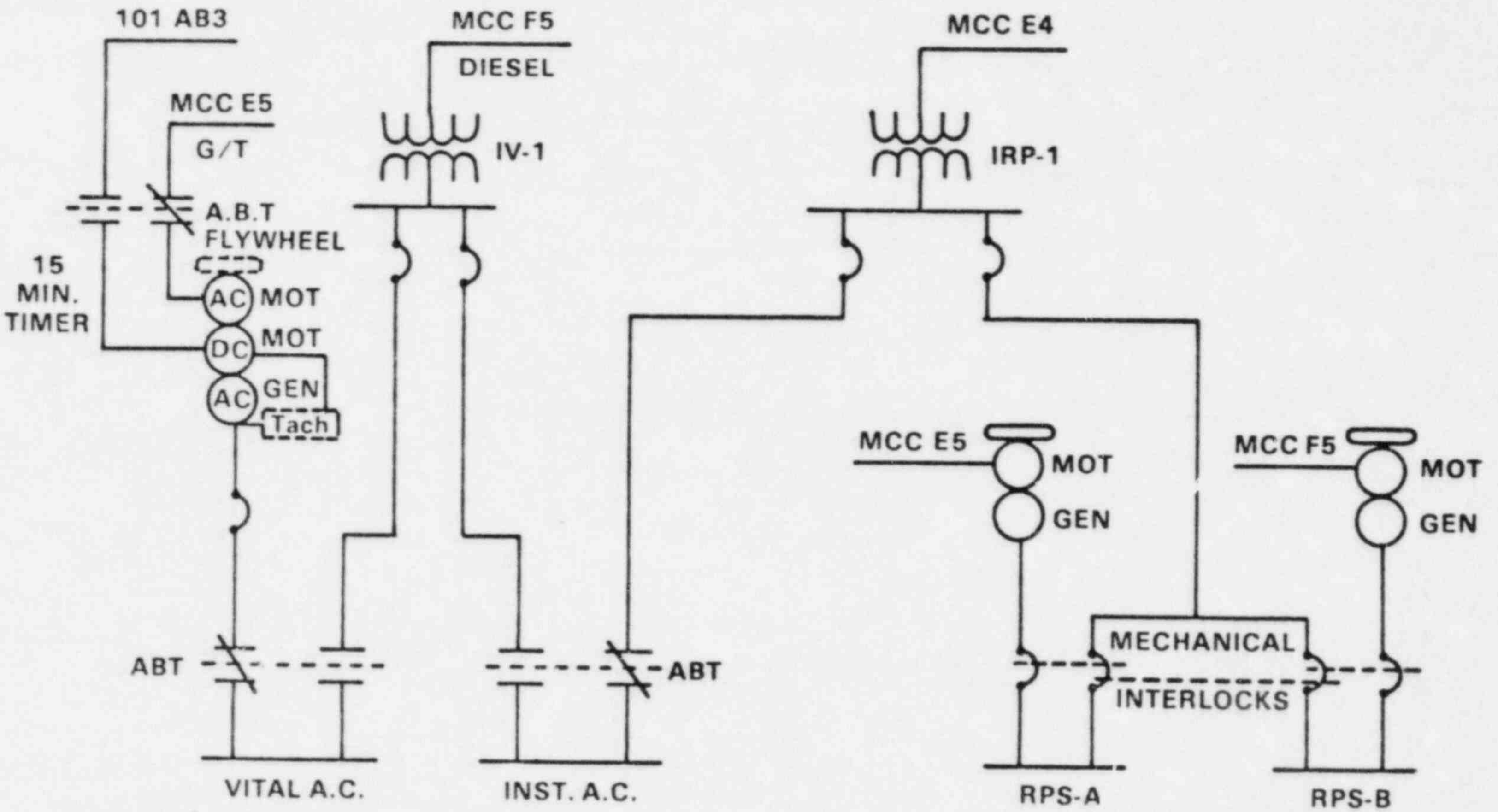


Figure VI-7.C.1.-1c.
Vital AC--Instrument AC Reactor Protection Bus Before

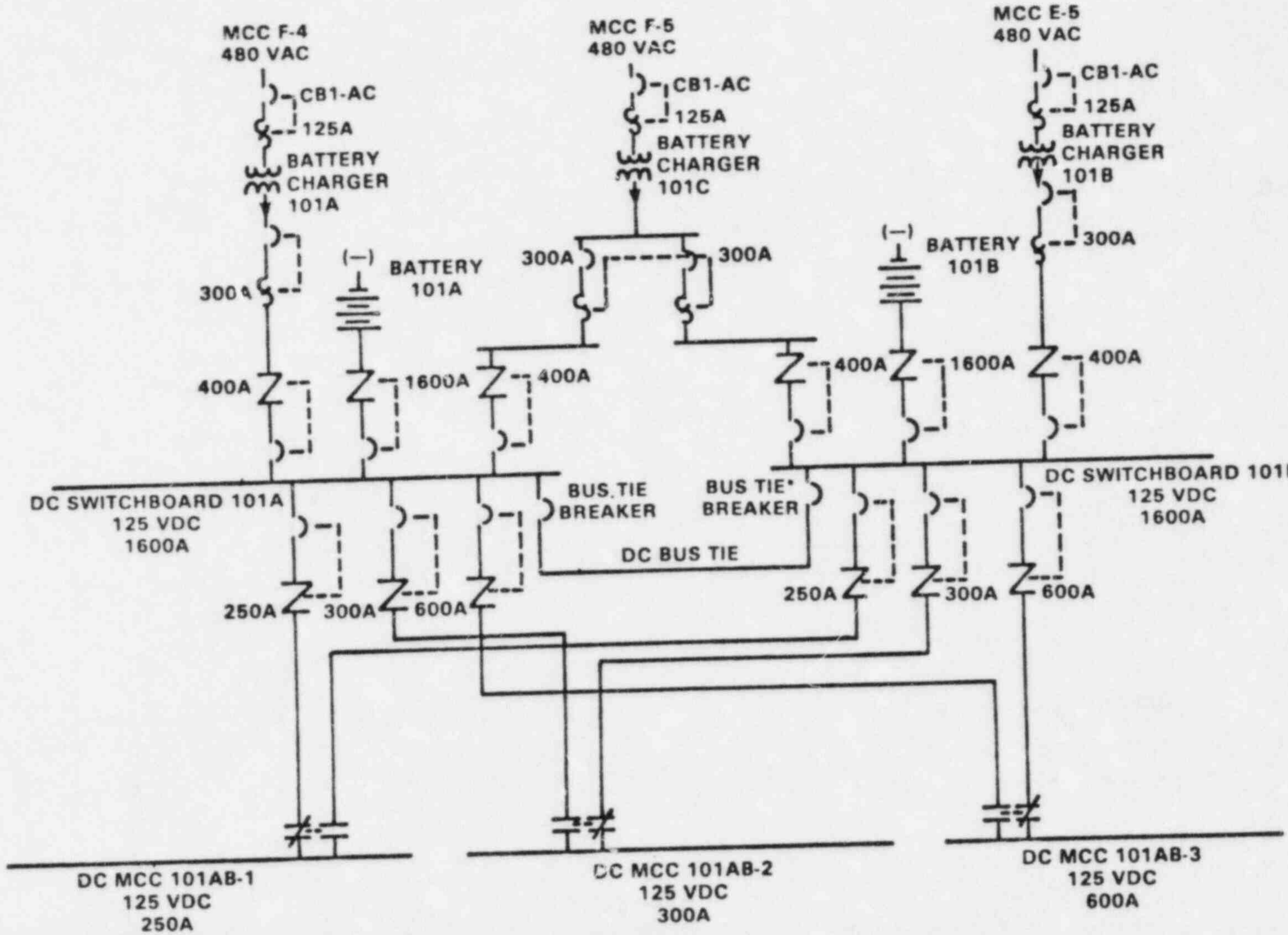


Figure VI-7.C.1.-1d. Millstone 1 DC Power System Before

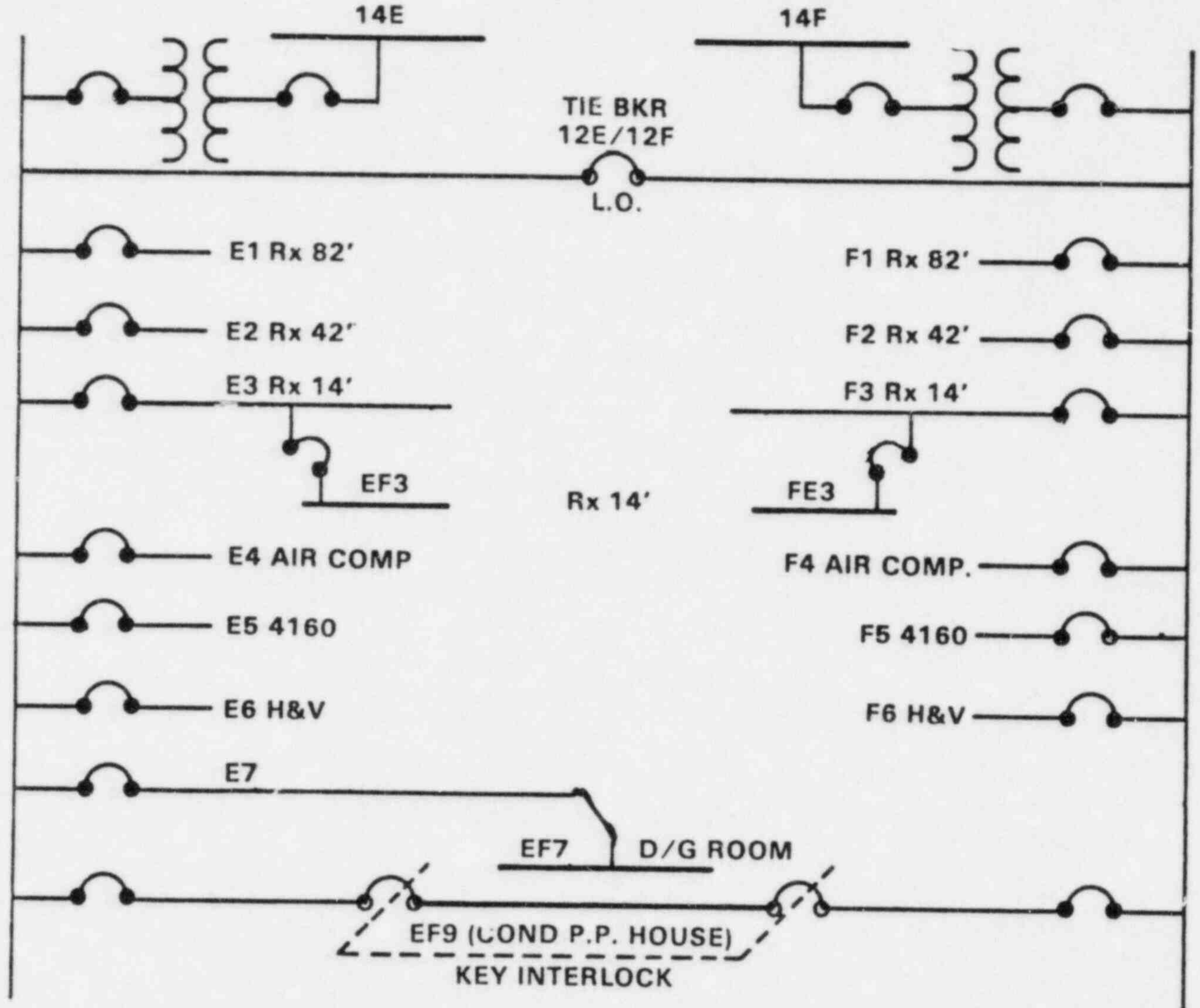


Figure VI-7.C.1.-2a. 480 Volt Distribution 12E-12F Bus After

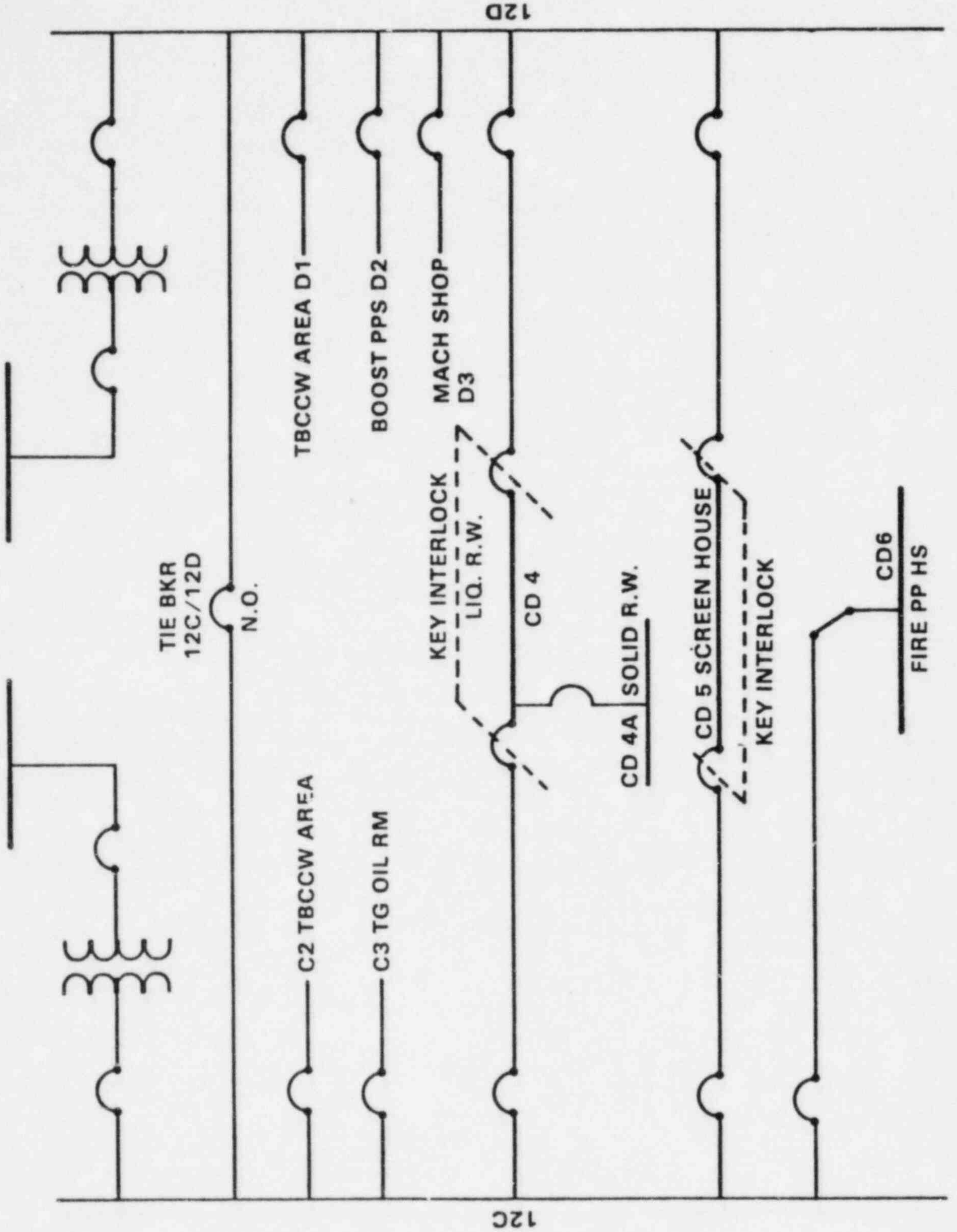


Figure VI-7.C.1.-2b. 480 Volt Distribution 12C-12D Bus After

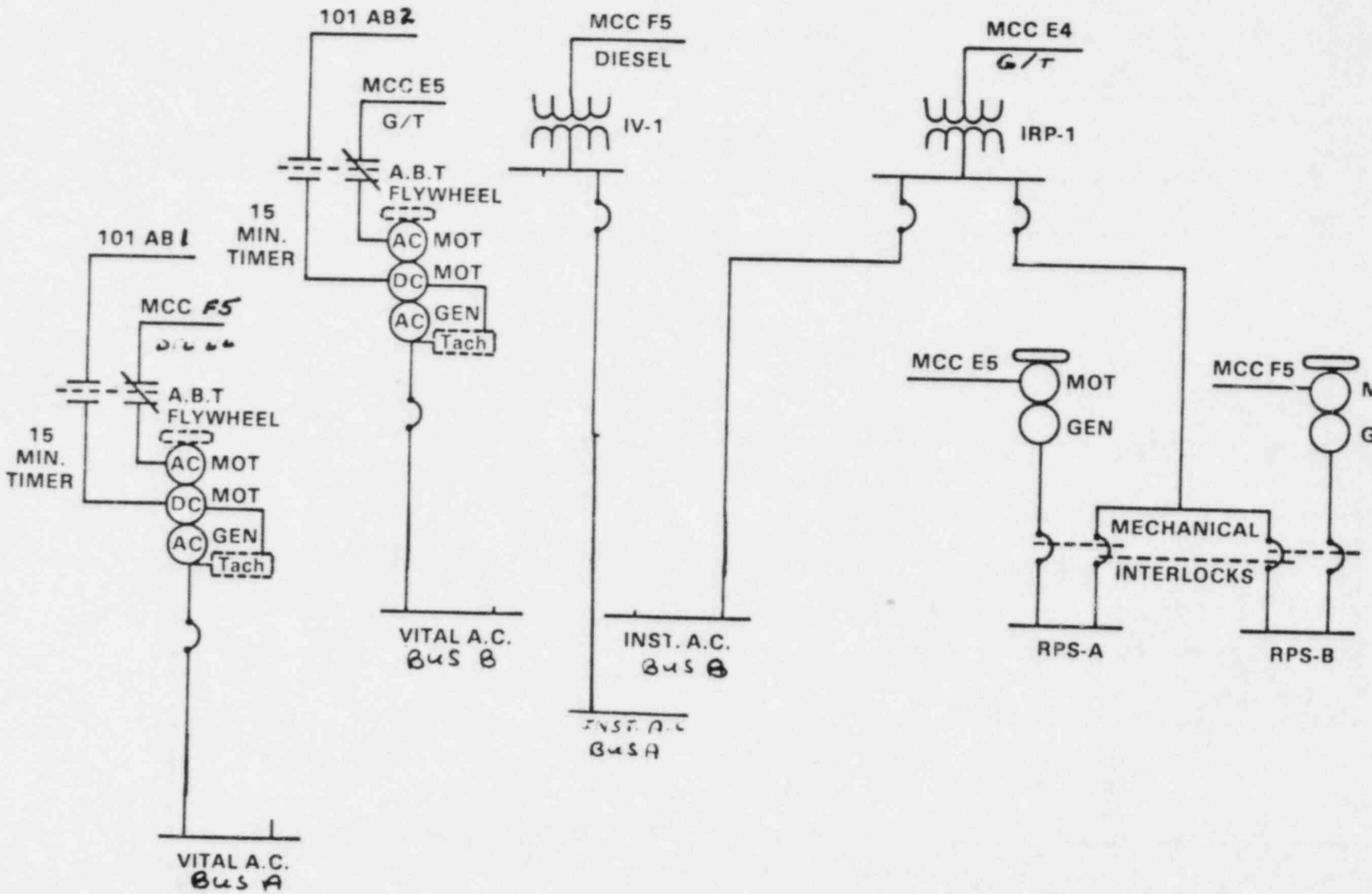
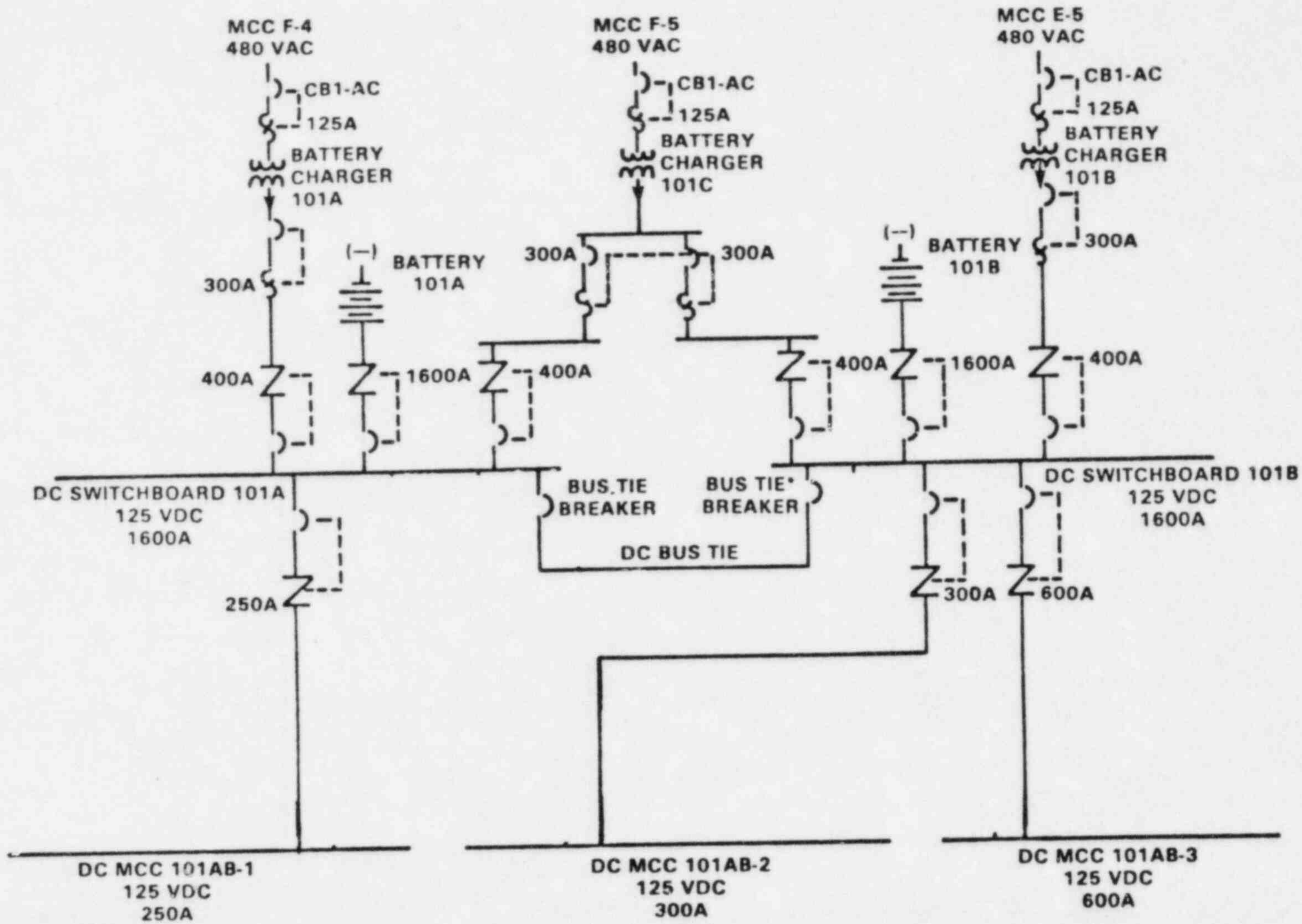


Figure VI-7.C.1.-2c.
Vital AC-Instrument AC Reactor Protection Buses After

Figure VI-7.C.1.-2d. Millstone 1 DC Power System After



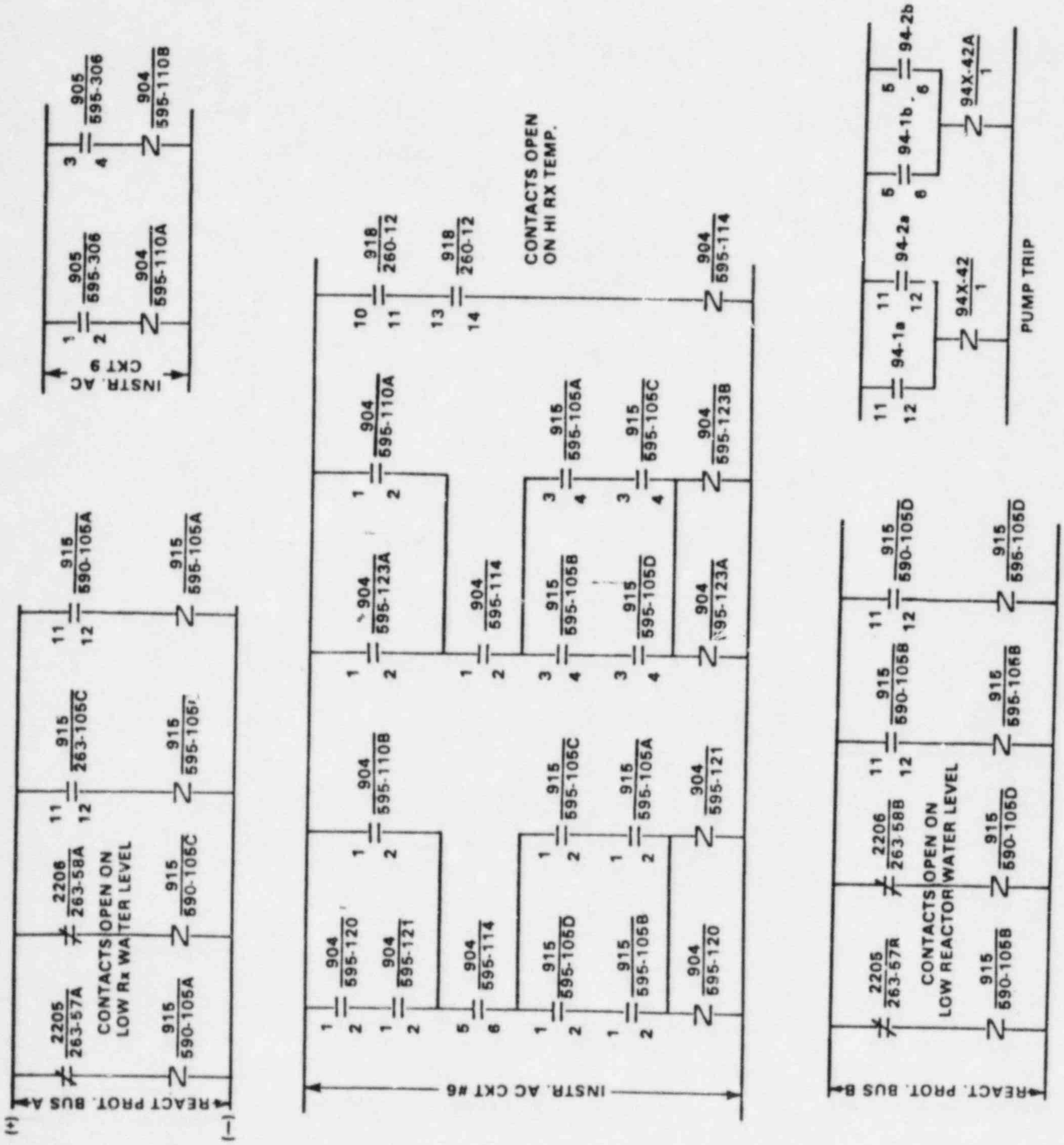


Figure VI-7.C.1.-3.
Shutdown Cooling System Control Wiring Schematics Before

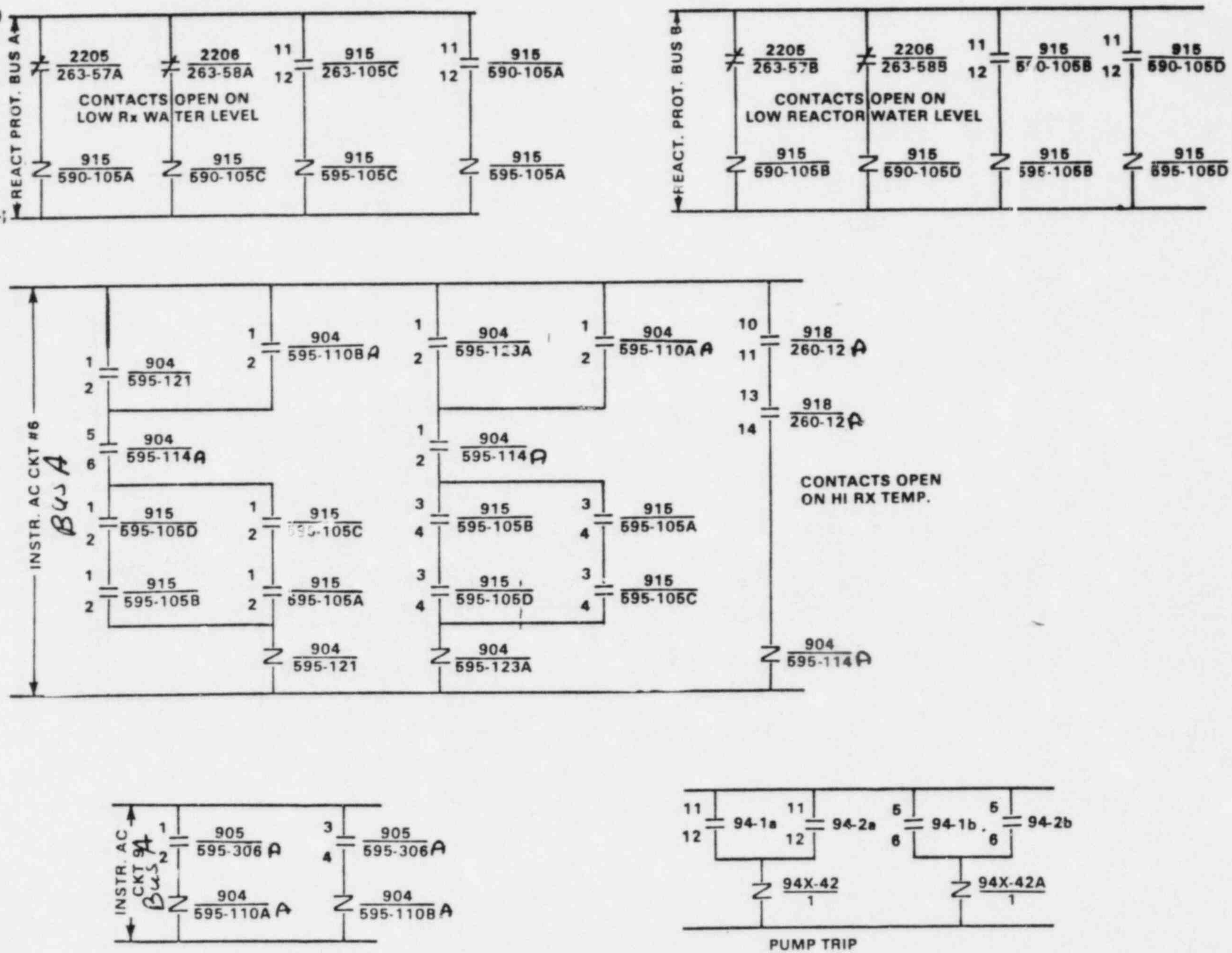


Figure VI-7.C.1.-4.
Shutdown Cooling System Control Wiring Schematics (Sheet 1 of 2) After

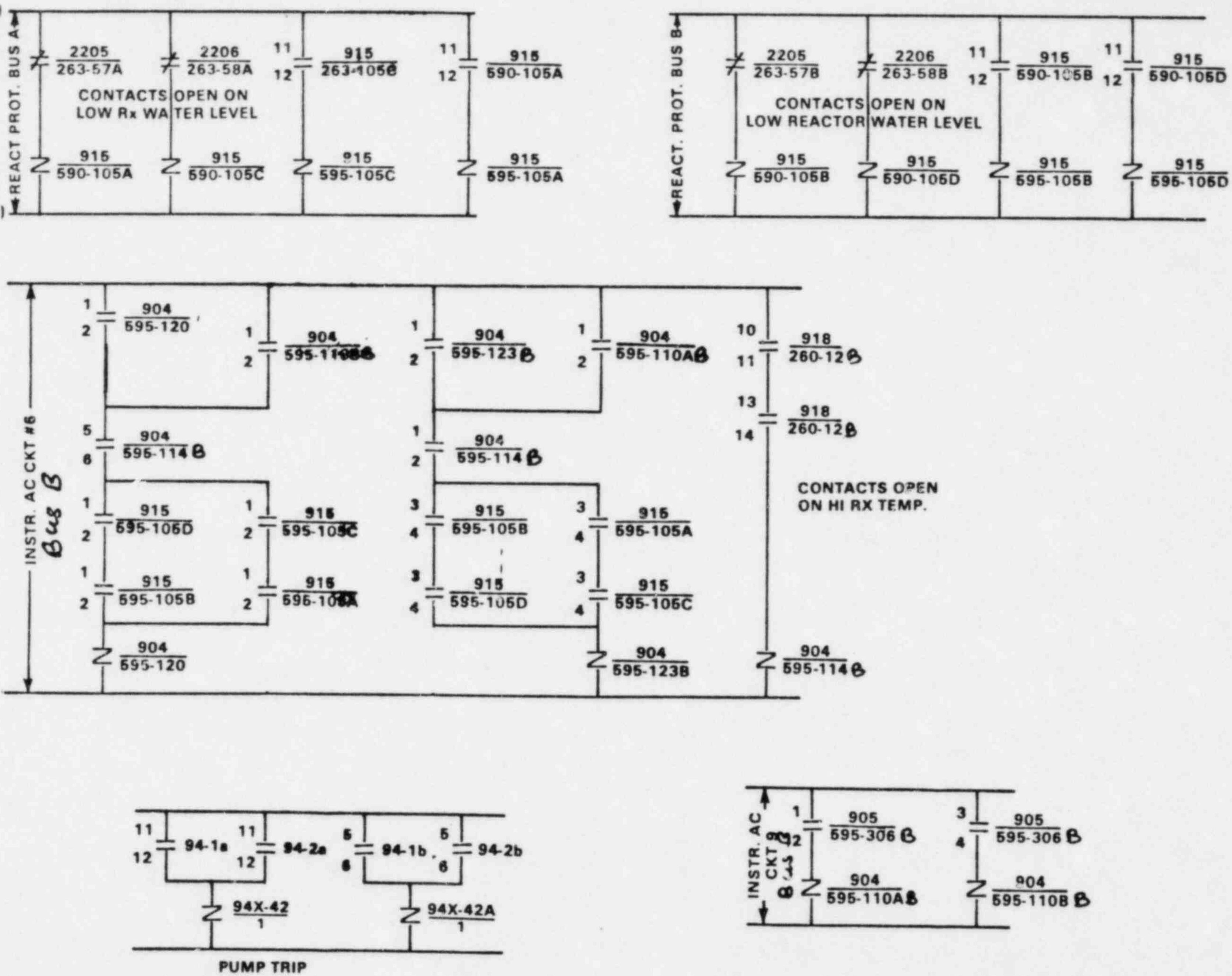


Figure VI-7.C.1.-4. Shutdown Cooling System Control Wiring Schematics (Sheet 2 of 2) After

VI-10.A Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing

1. NRC Evaluation

The RPS is not required to be tested as frequently as operating experience has indicated to be desirable. The deviations are listed on the following table.

Instrument Channel	Test	Standard Tech Spec Test Freq. Requirement	Millstone-1 Test Frequency
1. APRM flow biased high flux	Channel Check	8 hours	--
2. APRM reduced high flux	Channel Check	8 hours	--
3. IRM	Channel Check	8 hours	24 hours
4. High Steam Line Radiation	Channel Functional	7 days	1 month*
5. High Reactor Pressure	Channel Functional	1 month	1 month*
6. High Drywell Pressure	Channel Functional	1 month	1 month*
7. Low Reactor Water Level	Channel Functional	1 month	1 month*
8. High Water Level in Scram Discharge	Channel Functional	1 month	1 month*
9. Main Steam Line Isolation Valve Closure	Channel Functional	1 month	1 month*
10. Turbine Stop Valve Closure	Channel Functional	1 month	1 month*
11. Manual Scram	Channel Functional	1 month	1 month*
12. Turbine Control Valve Fast Closure	Channel Functional	1 month	1 month*
13. APRM Flow Biased High Flux	Channel Functional	at startup	1 month*
14. APRM Reduced High Flux	Channel Calibration	1 week/ semi annual	3 months

*Millstone Tech Specifications allow for a quarterly test frequency.

Additionally, response time testing is not performed on the RPS.

2. NRC Recommendation

A program for response time testing of all reactor protection systems should be initiated. Also, the Technical Specifications should be modified to reflect the higher tests frequencies of the current Standard Technical Specifications.

3. Systems Affected

The RPS and ESF are the systems affected by this issue.

4. Comments

In performing the PRA for the Millstone-1 IREP, the conditions that actually existed at the plant were modeled. The test frequencies used in the analysis were those that actually exist, not those required by the plant technical specifications. For the nine instrument channels that have a technical specification required test frequency of once every 3 months, but are actually tested on a monthly basis, the monthly test interval was used in the analysis. The proposed change in the Technical Specifications (the reducton of the test interval from quarterly to monthly) would not affect what is now being done at Millstone-1. From the risk analysis perspective, the change in the Technical Specifications will not have an effect on the plant's safety. This does not address the possibility that the test interval can be changed without notification to the NRC. Any such change could affect the results of the risk analysis for Millstone-1. However, as the tests are now performed, the proposed change in Technical Specifications does not affect the results of the Millstone-1 probabilistic risk analysis.

In evaluating the proposed requirement for response time testing, it is important to consider the significance of response time testing in a risk analysis. In a PRA, the timing of system response is relatively unimportant when discussing the short time periods measured by response time testing. In general, if a system functions automatically, it has succeeded. In particular, the time limit for RPS actuation in a PRA is that which ensures the success of the subcriticality function in time to allow other safety systems to prevent core melt. Whether or not design specifications are met is not particularly important. The time period of concern in a PRA is on the order of minutes, not seconds as in response time testing. The functional tests are sufficient to determine component and system operability in this time frame. This analysis does not address the need for rapid response for such functions as containment isolation where response time testing would affect the length and magnitude of a radioactive release in a non-core-melt accident. Such an analysis is not part of a risk assessment, which examines the risk due to core melt.

The final aspect of this issue is tests performed on the RPS instrument channels at longer intervals at Millstone-1 than the Standard Technical Specifications require, items 1, 2, 3, 4 and 14 in the table in section 1 of this topic. The increased testing of these instrument channels would increase the reliability of the affected instrumentation.

The Millstone-1 IREP analysis was performed assuming there were no channel checks on the APRMs and IRMs, a functional test on the high steam line radiation instruments each month, and that the APRM reduced high flux channels were calibrated quarterly. With this data these system components did not contribute to the dominant failure mechanisms of the RPS. The RPS failure probability is dominated by common mode mechanical failures. The increased testing recommended would lower the failure probabilities fo the affected instrumentation. However, none of this instrumentation contributed to the dominant failure modes of the RPS and the decrease in their failure probability would have no effect on the RPS faliure probability.

5. Analysis

No further analysis, beyond the Millstone-1 IREP study, is required for the core melt risk related portion of this issue.

6. Conclusion

The areas of concern in this issue do not impact the core melt frequency at Millstone-1. The changes in the test requirements, including response time testing, do not affect the results of the Millstone-1 IREP risk analysis, which only examines the risk due to core melt.

VII-1.A Isolation of Reactor Protection System From Nonsafety Systems, Including Qualifications of Isolation Devices

1. NRC Evaluation

The NRC evaluation found three areas where Millstone-1 did not comply with current licensing criteria. They are:

1. There are no isolation devices between the nuclear flux monitoring systems and the process recorders and indicating instruments.
2. Isolation devices are not provided to isolate the APRM system from the process computer.
3. Power supplies for the RPS channels are not IE equipment and there is inadequate isolation between each RPS channel and its power supply.

2. NRC Recommendation

Either suitable isolation devices are to be provided for these three exceptions or the acceptability of the present designs must be justified.

3. System Affected

Only the RPS is affected by this issue.

4. Comments

The worst possible effect of the lack of isolation devices between the nuclear flux monitoring system and the process recorders and indicating instruments is that a fault in the recorders/indicators would fail the nuclear instrumentation. This is true for the process computer and the APRM system. The analysis for the issue assumes that a fault exists in one of the nonsafety devices that has failed the nuclear instrumentation portion of the RPS.

The isolation devices between the RPS and the motor-generator power supply were to have been modified, in the Millstone-1 spring 1982 refueling outage, to comply with NRC requirements. The effect of inadequate isolation between the RPS and its power supply will not be analyzed.

5. Analysis

The assumption is made that a failure in the process recorders or the indicating instruments will fail the entire nuclear monitoring portion of the RPS. Additionally, it is assumed that this failure has occurred. Using these two assumptions the data used to evaluate the PRS fault tree as constructed during the

Millstone-1 IREP study was modified to model the nuclear monitoring portion of the RPS as failed. The failure probabilities used for the APRMs and IRMs were changed from their previous values to 1.0, indicating that these devices had failed.

This is a more restrictive case than the effect the process computer could have on the APRMs would produce. The use of these two assumptions incorporates potential process computer faults into the analysis.

An analysis of the RPS fault tree using this data showed no change in the system unavailability. Failure of the RPS was still dominated by common mode mechanical faults.

6. Conclusion

Extremely conservative assumptions were made in this analysis concerning the existence of and effects of faults in the process recorders, indicating instruments and process computer. With these assumptions, no change in the RPS unavailability was found. The potential failure of the nuclear monitoring portion of the RPS due to nonsafety grade equipment has no effect on the RPS reliability and does not have any effect on the core melt frequency at Millstone-1.

VII-3 Electrical, Instrumentation, and Control Features of Systems Required for Safe Shutdown

1. NRC Evaluation

The purpose of this NRC review was to ensure that the capability exists to attain safe shutdown with only offsite or only onsite power available. In particular, the systems required should have the required redundancy, meet the single failure criterion, and have the required capacity and reliability to perform the intended safety functions. It should be possible to operate these systems from inside or outside the control room. Millstone-1 meets the criteria for these systems, except that short-term and long-term cooling (RHR) is susceptible to a loss of indication in the control room as well as loss of certain control circuits to safe shutdown systems as a result of a loss of the ac (IAC) bus.

2. NRC Recommendation

An additional IAC power source is required so that Millstone-1 can be shut down from the control room with a single failure of an instrument bus.

3. Systems Affected

The systems affected by this system are the ac power system and the containment cooling and shutdown cooling systems, because they interface with the instrument ac bus.

4. Comments

Since the NRC recommendation did not specify a particular design change, other than the addition of a redundant power source, we have developed our own redesign of the system to address this issue. We do not claim that this is either the best or the only way to accomplish the goal but simply is a sensible and logical design alternative.

5. Analysis

The present design of the instrument ac power source is shown in Figure VII-3-1, along with the initial ac and RPS sources. Although the single vital ac bus was not mentioned in the evaluation, it is also nonredundant. Additionally, because of the way it is intertied with the shared backup power for itself and the IAC bus, it was felt that no logical redesign of IAC to provide redundant supplies could be accomplished without also including VAC in the redesign. The redesign which was developed is shown in Figure VII-3-2. Since both the IAC and VAC buses supply power to the entire plant, and do not represent redundant load groups, it became necessary to split the loads in half according to the associated equipment train which they affect. For most cases, the separation of A train and B train loads was rather simple. There was, however, one complication because only one control logic train existed for the shutdown cooling system, as shown in Figure VII-3-3. This required the creation of a new control logic design which had two trains, one to be associated with each new IAC bus. This is shown in Figure VII-3-4, sheets 1 and 2. All these modifications were evaluated by changing the fault trees from the Millstone-1 Interim Reliability Evaluation Program (IREP) study to represent the modified IAC/VAC system design discussed above, and then requantifying the dominant event tree sequences to determine if any risk reduction was realized.

The changes from resolving issue VI-7.C.1 were requantified simultaneously with this issue. Table VII-3-1 gives the change in each dominant Millstone-1 IREP core melt sequence frequency from requantification including the issue VI-7.C.1 and VII-3 changes.

6. Conclusions

Resolutions of issues VI-7.C.1 and VII-3 would reduce the Millstone-1 core melt frequency by 10 percent. It appears that most of this reduction is from the redundant instrument ac bus.

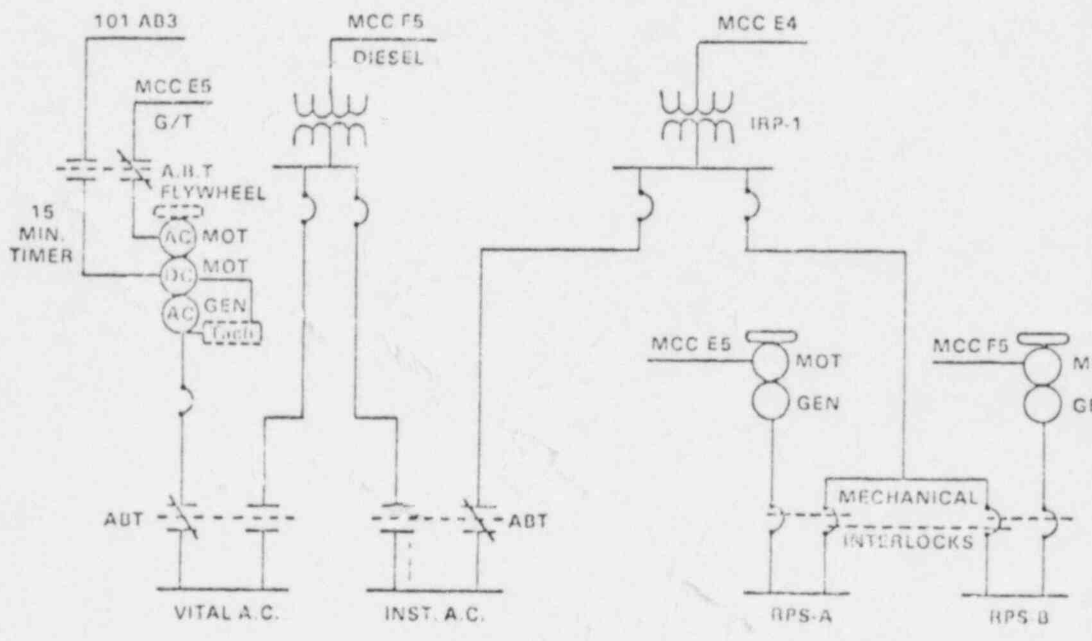


Figure VII-3-1. Vital AC-Instrument AC Reactor Protection Buses Before

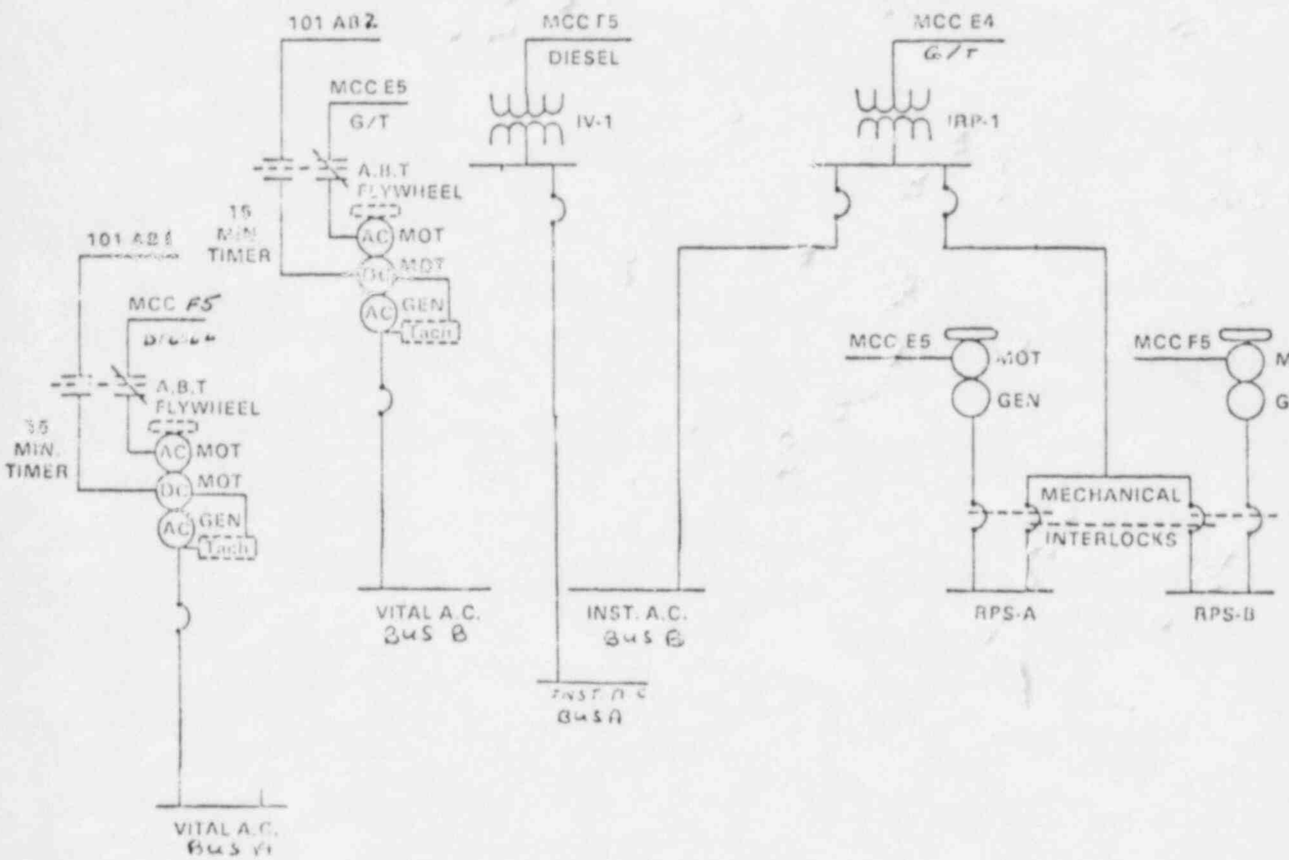


Figure VII-3-2. Vital AC-Instrument AC Reactor Protection Buses After

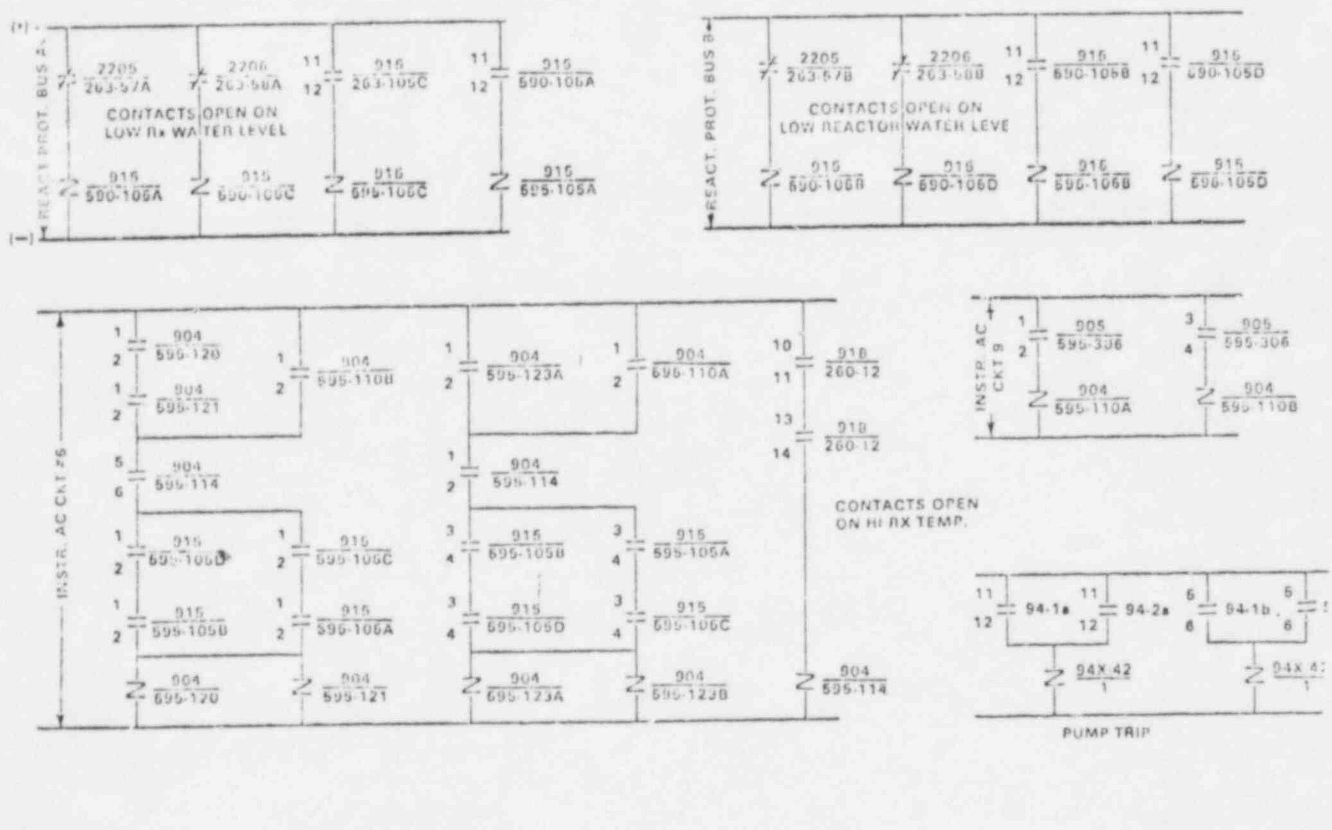


Figure VII-3-3. Shutdown Cooling System Control Wiring Schematics Before

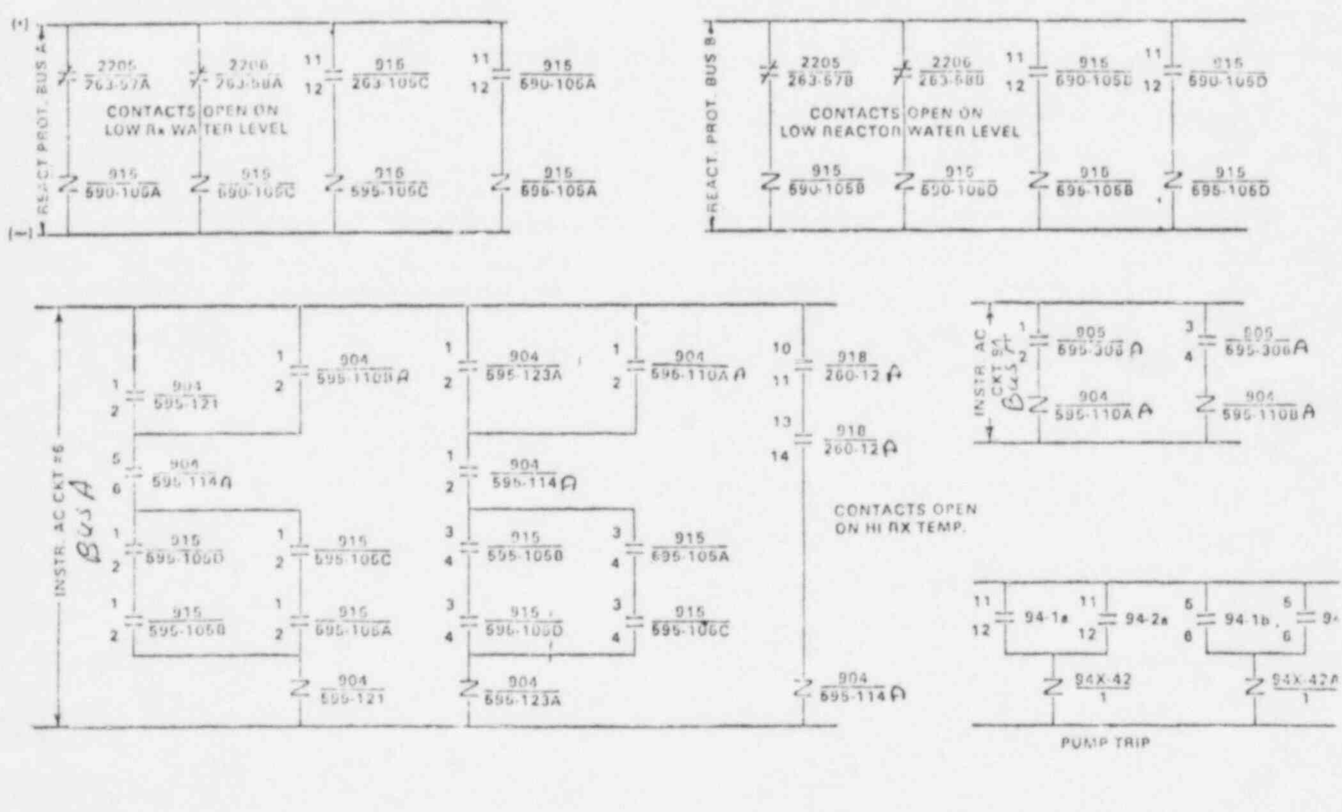


Figure VII-3-4.
Shutdown Cooling System Control Wiring Schematics (Sheet 1 of 2) After

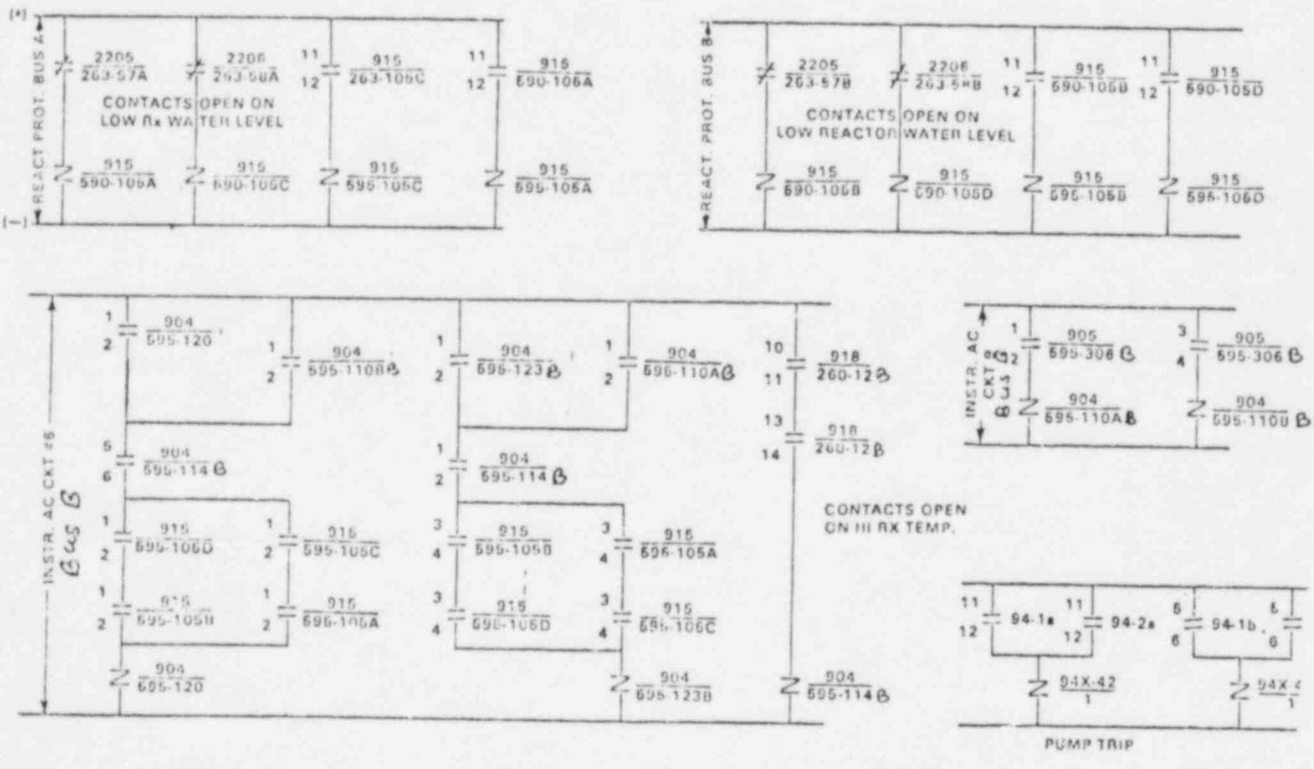


Figure VII-3-4.
Shutdown Cooling System Control Wiring Schematics (Sheet 2 of 2) After

Table VII-3-1
Changes in Dominant Millstone-1 Accident Sequence Frequencies Due to Resolution of Issues VI-7.C.1 and VII-3.

Sequence	Old Sequence Frequency $(Ryr)^{-1}$	New Sequence Frequence $(Ryr)^{-1}$
T_4JCD	6.7×10^{-5}	5.2×10^{-5}
T_4JCEFG	4.5×10^{-5}	4.0×10^{-5}
T_4KCEFG	2.7×10^{-5}	3.4×10^{-5}
T_4KCD	2.7×10^{-5}	4.2×10^{-5}
T_4LCD	2.6×10^{-5}	2.8×10^{-5}
T_2A	1.9×10^{-5}	1.9×10^{-5}
T_4JCDG	1.5×10^{-5}	1.1×10^{-5}
T_4JCMG	1.8×10^{-5}	1.2×10^{-5}
T_4LCEFG	1.4×10^{-5}	1.0×10^{-6}
T_4LCMG	1.1×10^{-5}	6.3×10^{-6}
T_4KCDG	1.0×10^{-5}	6.6×10^{-6}
T_4KCMG	9.3×10^{-6}	6.8×10^{-6}
Total	2.9×10^{-4}	2.6×10^{-4}

VIII-2 Onsite Emergency Power Systems--Diesel Generators

1. NRC Evaluation

The diesel generator meets all current criteria with regard to its protective interlocks and annunciators. It was found that several of the protective interlocks for the gas turbine generator were not bypassed or do not require coincident logic, apparently contrary to current licensing criteria. These protective trips are:

Light-off Speed Not Reached in 20 sec.
Light-off Temperature Not Reached 15 sec after Light Off
Starting Air-Ignition Cut-Off Speed Not Reached in 60 sec. After Start
Generator Excitation Speed Not Reached in 60 sec
High Exhaust Gas Temperature
High Lube Oil Temperature
High Gas Generator Speed
High Turbine Overspeed
High Vibration Jet
Low Lube Oil Pressure
Loss of Excitation
Opening of Exciter Breaker
Generator Differential
Negative Sequence
Reverse Power
Generator Underspeed
Voltage Restrained Overcurrent

2. NRC Recommendation

The gas turbine annunciators should be brought into conformance with the requirements of Paragraph 4.20 of IEEE Std. 279-1971. This includes separation of the annunciators for disabling and nondisabling faults and wording on the disabling annunciator stating that the diesel generator is unable to start. The protective interlocks should be brought into conformance by bypassing the trips listed above or requiring coincident signals for the trips to occur. This does not apply to the generator differential or voltage restrained overcurrent trips which are acceptable.

3. System Affected

The emergency ac power system is the sytem affected.

4. Comments

In the Millstone-1 IREP analysis, the evaluation of the gas turbine generator did not include the possibility of operator recovery if the gas turbine did not automatically start due to disabling faults. However, the plant operating procedures require the operator to verify that the emergency ac power supplies have automatically started. If they have not, the operator is to attempt to start the diesel and/or gas turbine generators. Since the procedures require the operator to attempt to start the gas turbine any time it does not start automatically, the separation of gas turbine failure annunciators into disabling and nondisabling fault annunciators does not increase the probability that the operator will attempt to start the gas turbine if is has failed to automatically start.

5. Analysis

A simplified model of the trips of interest for the gas turbine generator would consist of a sensor for each of the conditions monitored with the output going to a relay that would, in turn, transmit a signal to the gas turbine trip coil. This implies that, for each of the 15 protective interlocks that the NRC recommends be bypassed (or coincident logic be installed), there are three possible sources of a spurious trip signal. The spurious signal could be caused by a sensor failure (spurious signal), a relay coil failure (premature closing), or a relay contact pair failure (spurious contact closure). The data for these events is given in Table VIII-2-1. The data is derived from WASH-1400 (the Reactor Safety Study) and IEEE-500.

During the monthly test of the gas turbine generators, these trip signals are not disabled. If a spurious trip signal was present during the test the gas turbine would not have started and, since each trip signal is provided by a single sensor, the test is an accurate test of the status of the protective interlocks. The fault exposure time, one-half the test interval, for the protective trip failures is therefore the same as for the gas turbine generator, one-half a month.

The failure probability for the gas turbine generator is 6E-02, from the Millstone-1 IREP study. This data is derived primarily from test data and therefore includes failure of the protective interlocks: spurious trip signals. The total failure probability for protective interlocks (spurious actuation) is approximately 1E-3. Subtracting this figure from the gas turbine generator failure probability, the failure probability of the gas turbine generator with the protective interlocks bypassed is 5.9E-2.

This failure probability was used to requantify the Millstone-1 IREP analysis, replacing the gas turbine generator failure probability used in the original analysis. The effect of this faiulre probability reduction for the dominant sequences of the Millstone-1 IREP analysis is shown in Table VIII-2-2.

Reducing the gas turbine generator failure probability affected all but one of the 12 dominant accident sequences. The only one not affected is the loss of power conversion transient followed by a failure of RPS. The total effect of the gas turbine generator failure probability reduction is to reduce the core melt frequency by 1.3E-6/Ryr (of a total frquency of 2.9E-4 for the dominant sequences).

6. Conclusion

The reduction in core melt frequency due to the reduction of the gas turbine generator failure probability, gained by bypassing the protective interlocks is less than a 1 percent.

Although this particular item had very little impact on the plant risk, the reliability of the gas turbine and diesel generators are important factors in the risk due to core melt at Millstone-1. The failure of the gas turbine generator appears in cut sets that contribute approximately a quarter of the dominant accident (core melt) frequency. The failure probability of the diesel and gas turbine generators are relatively high and a significant improvement in their reliability would reduce the overall plant risk.

Table VIII-2-1
Protective Trips--Spurious Operation Data

Protective Interlock	λ_s	Fault Exposure Time	Probability of Spurious Operation
Light-Off Speed Not Reached in 20 sec	8.7E-8 hr^{-1}	360 hrs	3.1E-5
Light-Off Temp. Not Reached After Light Off	2.5E-7 hr^{-1}	360 hrs	9.0E-5
Starting Air Ignition Cut Off Speed Not Reached 60 secs After Start	8.7E-8 hr^{-1}	360 hrs	3.1E-5
Generator Excition Speed Not Reached in 60 secs	8.7E-8 hr^{-1}	360 hrs	3.1E-5
High Exhaust Gas Temperature	2.5E-7 hr^{-1}	360 hrs	9.0E-5
High Lube Oil Temperature	2.5E-7 hr^{-1}	360 hrs	9.0E-5
High Gas Generator Speed	8.7-8 hr^{-1}	360 hrs	3.1E-5
High Turbine Overspeed	8.7E-8 hr^{-1}	360 hrs	3.1E-5
High Vibration Jet	4.1E-7 hr^{-1}	360 hrs	1.5E-4
Low Lube Oil Pressure	9.4E-8 hr^{-1}	360 hrs	3.4E-5
Loss of Excitation	2.5E-7 hr^{-1}	360 hrs	9.0E-5
Opening of Exciter Breaker	2.3E-8 hr^{-1}	360 hrs	8.3E-6
Negative Sequence	2.5E-7 hr^{-1}	360 hrs	9.0E-5
Reverse Power	2.5E-7 hr^{-1}	360 hrs	9.0E-5
Generator Underspeed	8.7E-8 hr^{-1}	360 hrs	3.1E-5
Relay coil--spurious activation*	1E-8 hr^{-1}	360 hrs	3.6E-6
Relay contacts--spurious closure*	1E-8 hr^{-1}	360 hrs	3.6E-6
Total			1.0E-3

*One for each protective interlock.

Table VIII-2-2
Effects of Bypassing Gas Turbine Generator Protective Trips

Dominant Sequence	Sequence Frequency*	Frequency* of Cut Sets With GTG Failure	Frequency* of Cut Sets With Reduced GTG Failure Rate	Sequence Frequency* Reduction
T_4JCD	6E-5	6.5E-6	6.4E-6	1E-7
T_4JCEFG	4E-5	1.37E-5	1.35E-5	2E-7
T_4KCD	3E-5	5.0E-6	4.9E-6	1E-7
T_4KCEFG	3E-5	1.37E-5	1.34E-5	3E-7
T_4LCD	3E-5	2.01E-6	1.98E-6	3E-8
T_2A	2E-5	0.0	0.0	0.0
T_4JCDG	2E-5	7.5E-6	7.4E-6	1E-7
T_4JCMG	2E-5	7.6E-6	7.5E-6	1E-7
T_4LCEFG	1E-5	4.3E-6	4.2E-6	1E-7
T_4LCMG	1E-5	4.3E-6	4.2E-6	1E-7
T_4KCDG	1E-5	5.9E-6	5.8E-6	1E-7
T_4KCMG	9E-6	6.0E-6	5.9E-6	1E-7
Total	2.89E-4	7.65E-5	7.52E-5	1.3E-6

*Per Reactor year

VIII-3.A Station Battery Test Requirements

1. NRC Evaluation

The Millstone-1 battery tests do not comply with current NRC test requirements. These requirements include a battery service test to verify that the battery can carry emergency loads for 2 hours, during shutdown at least once per 18 months, and a battery discharge test, to verify that the battery capacity is 80 percent of the manufacturer's rating, performed once per 60 months. Currently the Millstone-1 Technical Specifications do not require any battery service test. The battery discharge test is performed every 18 months.

2. NRC Recommendation

The Millstone-1 Technical Specifications should be changed to require battery service tests every 18 months.

3. Systems Affected

The dc power system is the only system affected.

4. Comments

In the Millstone-1 IREP study the test interval used for detecting battery faults was 1 week. This corresponds to the frequency of the specific gravity and voltage tests on the station batteries (Millstone procedure SP 780.1). The use of this test interval makes the use of the results from the Millstone-1 IREP study in a comparison of the battery unavailabilities with and without the proposed NRC changes inappropriate.

The use of weekly test intervals to determine the unavailabilities of the station batteries yields a lower unavailability than if the batteries are tested every 18 months. The NRC conclusion that the batteries are never properly, fully tested will yield an even higher battery unavailability. Since the Millstone-1 IREP does not model this higher unavailability, the gain in system reliability due to the change in testing cannot be evaluated against the Millstone-1 IREP. See the Methodology and Results sections of this report.

5. Analysis

If the station batteries have never been adequately tested their unavailability, at this time, can be expressed as:

$$P(\text{batt}) = \lambda_o t_1$$

where λ_o = battery failure rate (hr^{-1})
t_1 = time in service (hr)

For a component that is routinely tested, the unavailability can be expressed as

$$P(\text{batt}) = \overset{\frac{1}{2}}{\cancel{1/2}}\, \lambda_o\, t_2$$

where t_2 = time between tests.

From these two equations it is obvious that $\frac{1}{2}$ the reduction in the battery unavailability is the ratio of t_1 and $\cancel{1/2}$ t_2. In this case t_1 would be the life of the plant (for Millstone-1 approximately 12 years) and t_2 would be 18 months, as recommended by the NRC. This yields a reduction of the battery unavailability by a factor of 16.

6. Conclusions

The Millstone-1 IREP analysis of the station batteries is based on the assumption of weekly tests of the batteries. In addition to these weekly tests, every refueling the batteries are tested during 628.1 Intergrated Simulated Automatic Actuation of FWCI, Core Spray, LPCI, Diesel and Gas Turbine Generation. During this test, the batteries must pick up all the loads they would be required to pick up during a loss of normal power during power operation. Between this test and the weekly surveillance tests it was felt that the batteries were adequately tested, even though the integrated test would not require 2 hours of battery operation at full load. (The batteries would have to carry the expected loads.)

However, if the assumption is that the test procedures are not sufficient to test the batteries, then the battery unavailabilities would be reduced by a factor of 16 by going to the recommended battery surveillance. This would impact the core melt frequency since when the Millstone-1 IREP assumptions are used the batteries do contribute to some of the dominant accident sequences. In addition, a much higher battery unavailability could cause other sequences to become dominant. A reduction in the battery unavailabilities would reduce the total core melt frequency.

VIII-3.B DC Power System Bus Voltage Monitoring and Annunciation

1. NRC Evaluation

The dc battery and bus monitoring system should provide adequate information to the operator so that he can determine battery and bus status and take corrective action if necessary. The Millstone-1 system is deficient in that the following control room indications are not provided:

Battery Current
Battery Charger Output Current
DC Bus Voltage
DC Bus Ground Alarm
Battery Breaker Open Alarm
Battery Charger Output Breaker Open Alarm

2. NRC Recommendation

Instrumentation should be installed to provide control room indications and alarms for the status of the items listed in Section 1.

3. Systems Affected

The system affected by this issue is the dc power system.

4. Comments

This analysis is based on the Millstone-1 IREP study and NUREG-0666 "A Probabilistic Safety Analysis of dc Power Supply Requirements for Nuclear Power Plants." The evaluation of detectable and undetectable faults of the battery is based on NUREG-0666.

5. Analysis

The data used in the Millstone-1 IREP study were based on WASH-1400 data. In the Millstone-1 IREP analysis the battery test interval used was 1 week (the time between battery specific gravity tests). This implies that no battery faults are detected until the weekly battery tests.

With the recommended dc battery and bus monitors added, it is expected that at least some of the battery faults would be detected immediately rather than at a battery test. NUREG-0666 included an evaluation of the effectiveness of battery monitoring. From the events reported in Licensing Event Reports it was discovered that approximately one-half of the battery faults reported were discovered during a battery test even though the minimum annunciation requirements were met.

With this information, a new set of data was developed for the Millstone-1 dc power system to model the system with the recommended modifications in system annunciation. All the data are shown in Table VIII-3.B-1.

The dominant sequences of the Millstone-1 IREP study were reevaluated using the reduced battery and battery breaker unavailabilities. Additionally, the sequences were evaluated using these reduced unavailabilities and a battery maintenance unavailability reduced by 50 percent, the same reduction found in the battery unavailability. This was done since the dominant unavailability in the dc system was found to be the battery maintenance outage. (The Millstone-1 IREP used the Technical Specification limit of 1 week, 128 hours, for operation of the plant with one battery out of service as the repair time for batteries during plant operation.) The maintenance unavailability was handled as a separate reanalysis since the battery monitoring would not affect the calculated battery unavailability due to maintenance.

The effects of these two analyses of the dominant sequences are shown in Table VIII-3.B-2. In the analysis in which only the battery and battery breaker unavailabilities were reduced, the contribution of the cut sets containing battery faults was reduced from 5.5 percent to 4.9 percent of the total core melt frequency. In the analysis where the battery maintenance unavailability was also reduced, the contribution of cut sets containing battery faults was reduced from 5.5 percent to 3 percent.

6. Conclusion

The addition of the battery and bus monitors does reduce the contribution of battery faults to the Millstone-1 core melt frequency. By also reducing the battery maintenance time by the same factor as the battery unavailability, the contribution of the battery system failures (including maintenance unavailability) to the dominant sequences is reduced by approximately 50 percent.

It is of interest to note that the factor by which the battery faults are reduced is independent of the test interval used in the analysis. Had a longer test interval been assumed the original contribution of battery faults to the dominant sequences would have been greater. The addition of the recommended monitors would have reduced this contribution by approximately 50 percent.

Table VIII-3.B-1
Battery Data

Fault	$\lambda (hr^{-1})$	Fault Exposure Time	Unavailability
DC Battery Faults			
a. Millstone IREP	3E-6	84 hrs 1)	2.5E-4
b. Modified			
1. detectable	1.5E-6	1 hr 2)	1.5E-6
2. not detectable	1.5E-6	84 hrs	1.2E-4
DC Battery Breaker Faults			
a. Millstone-1 IREP	1E-6	24 hrs	2.4E-5
b. Modified	1E-6	1 hr 2)	1E-6
DC Battery-Test/Maintenance Unavailability			
a. Millstone-1 IREP	3E-6	128 hrs	5.04E-4
b. Reduced 50 percent			2.5E-4

1) 84 hrs is one-half of 1 week. Component unvailability is defined as $\cancel{1/2}\lambda t$; λ = hourly failure rate, t = time between test.

2) for faults detected immediately the unavailability is defined as λt; λ = hourly failure rate, t = time interval during which the component failure could exist and component would be demanded in reponse to an accident initiator.

Table VIII-3.B-2
Results From Battery Failure Reductions and Battery Maintenance Unavailabilty Reductions

Sequence	Core Melt Frequency (Ryr^{-1})	Battery Fault Contribution, IREP (Ryr^{-1})	Battery Fault Contribution Improved Annunciation (Ryr^{-1})	Reduction With Improved Annunciation (Ryr^{-1})	Battery Fault Contribution, Improved Annunciation Annunciation and 50% Maintenance Reduction (Ryr^{-1})	Reduction with Improved Annunciation and 50% Maintenance Unavailability Reduction (Ryr^{-1})
T_4JCD	6E-5	2.4E-6	2E-6	4E-7	1.3E-6	1.1E-6
T_4JCEFG	4E-5	7.6E-7	6.9E-7	7E-8	4.1E-7	3.5E-7
T_4KCD	3E-5	1.8E-7	4.6E-8	1E-7	2.7E-8	1.5E-7
T_4KCEFG	3E-5	8.4E-6	7.8E-6	6E-7	4.5E-6	3.9E-6
T_4LCD	3E-5	3.0E-6	2.6E-6	4E-7	1.7E-6	1.3E-6
T_2A	2E-5	0.0	0.0	0.0	0.0	0.0
T_4JCDG	2E-5	1.9E-7	1.6E-7	3E-8	1.1E-7	8.0E-8
T_4JCMG	2E-5	3.4E-11	2.9E-11	5E-12	1.9E-11	1.5E-11
T_4LCEFG	1E-5	2.0E-7	1.8E-7	2E-8	1.1E-7	9.0E-8
T_4LCMG	1E-5	1.4E-7	1.3E-7	1E-8	7.5E-8	6.5E-8
T_4KCDG	1E-5	8.2E-7	7.4E-7	8E.8	4.4E-7	3.8E-8
T_4KCMG	9E-6	2E-9	1.7E-7	3E-10	1.1E-9	9.0E-10
Total	2.9E-4	1.6E-5	1.4E-5	1.7E-6	8.6E-6	7.4E-6

IX-3 Station Service and Cooling Water Systems

1. NRC Evaluation

The systems required to transfer heat from structures, systems, and components important to safety should have suitable redundancy in components and features, suitable interconnections, leak detection, and isolation capabilities to ensure system operation assuming a single failure and either on- or offsite power. In both the service water system and the turbine building closed cooling water (TBSCCW) system, there are nonredundant sections of pipe whose failure could result in system failure.

2. NRC Recommendation

The licensee should show that a failure in a section of nonredundant pipe will not fail the system or that the system is nonessential.

3. Systems Affected

The systems directly affected by this issue are the service water system and the TBSCCW system.

4. Comments

In the Millstone-1 IREP study, the failures of pipe segments in these systems were analyzed and their contributions to the system failure rates were determined to be negligible. Both of these systems supply a support function, cooling, to other plant systems. In evaluating the contribution of piping failures the unavailability of these two systems and the unavailabilities of the systems supported by the service water and TBSCCW systems were considered.

In the Millstone-1 IREP analysis the primary system of interest supported by the TBSCCW system was the feedwater coolant injection (FWCI) system which consists of the feedwater and condensate systems. The FWCI system has a failure probability several orders of magnitude larger than the failure probability of the pipe segments in the TBSCCW system. The pipe segment failure probability would have no effect on the TBSCCW system or FWCI system failure probabilities.

The service water system provides cooling for the TBSCCW, reactor building closed cooling water (RBCCW), and ac power (specifically the diesel generator) systems. As with the TBSCCW system, component failures within the service water system and the systems it supports are the dominant failure modes for the systems. Piping failures are several orders of magnitude less probable than the component faults and therefore do not contribute significantly to the service water system failure probability.

5. Analysis

Both of the systems to be examined are normally operating systems. For the pipe failure to affect the system performance following a transient or LOCA initiator the pipe failure would have to occur in the time period after the initiator during which the plant safety systems are responding to the initiator. In the Millstone-1 IREP analysis, and other PRAs, this time period is assumed to be 24 hours. The failure of either the service water system or the TBSCCW system prior to an initiating event is not considered significant since if either of these systems fail the plant would have to be shut down (cooling to the power conversion system is lost).

The failure rate for pipe segments, from WASH-1400, is 1E-10 hr^{-1} per pipe segment for pipes of >3 in. in diameter and 1E-9 hr^{-1} per pipe segment for pipes of ≤3 in. in diameter. The expected failure probabilities for pipe segments in the 24 hours following the initiating event is 2.4E-9/pipe segment >3 in. diameter and 2.4E-8/pipe segment ≤3 in. diameter. These failure probabilities become insignificant when compared to some of the component failures required to render these systems inoperable. For example, the probability of failure to run for one TBSCCW pump in the same 24-hour period is approximately 7E-4, and the failure to start the second TBSCCW pump (only one is normally running) has a probability of 1E-3. The probability of TBSCCW system failures alone is approximately 7E-7. This is two orders of magnitude larger than the pipe break probability.

In the Millstone-1 IREP analysis, no failures of components in the TBSCCW system appeared in any of the dominant cut sets of any of the dominant accident sequences. Therefore, the pipe failures will not contribute to the dominant accident sequences since the probability of pipe failure is less than other system failure mode probabilities.

There were failures in the service water system that did appear in the dominant sequence cut sets. However, these failures, or combinations of failures, all had failure probabilities of 10^{-3} or greater. Two of these failures were the failure of 1-SW-9 to close (probability=1.7E-2) and the loss of function of the service water system strainer (probability = 2.4E-2). As can be seen, both of these failures are several orders of magnitude larger than any pipe failures and would make the contribution of pipe segment failures insignificant.

Pipe segment failures in these two systems could lead to a loss of the power conversion system (PCS). However, when compared to the frequency of a loss of the PCS (a value of 2.80/Ryr was used in the Millstone-1 IREP analysis) from other causes, the frequency of loss of PCS due to failures in TBSCCW and service water system pipe segments is extremely small (approximately 9×10^{-6}/pipe segment/Ryr). This small increment in frequency would have no impact on the plant core melt frequency. The pipe failures in the service water system would affect the shutdown cooling system also, but there are other systems that can perform the cooling function of this system (the low pressure coolant injection system water system). This combined with the low frequency of pipe segment failures in the service water system makes those failures unimportant as PCS failure transient initiators.

6. Conclusion

Failure of nonredundant pipe segments in the service water and TBSCCW systems do not make a contribution to the plant core melt frequency. These pipe rutures were considered for their effect on the Millstone-1 emergency systems and as possible transient initiators, i.e. loss of PCS.

IX-5 Ventilation Systems

1. NRC Evaluation

It is required that the ventilation systems have the capability to provide a safe environment for plant personnel and for engineered safety features. A number of deviations were found at Millstone.

- The consequences of the inability of the standby gas treatment system (SGTS) to ventilate high radioactivity areas has not been addressed.
- The LPCI and core spray systems ventilation systems is subject to disabling single failures.
- Insufficient information exists to conclude that ventilation is adequate for the following systems:

    a. Feedwater Coolant Injection System (FWCI)
    b. Station Service Water System (SWS)
    c. Emergency Service Water System (ESW)
    d. Turbine Building Secondary Closed Cooling Water System (TBSCCW)
    e. Diesel Generator Room
    f. Auxiliary Electrical Equipment Room
    g. Station Battery Rooms.

2. NRC Recommendations

No specific recommendation, other than the submittal of additional information, is made for this issue.

3. Systems Affected

The systems affected by this issue are LPCI, core spray, FWCI, SWS, ESW, TBSCCW, and ac and dc electrical power. Additionally, the "human" system is affected by the habitability facet of this issue.

4. Comments

The need for ventilation systems was reviewed in great detail during the Interim Reliability Evaluation Program (IREP) analysis of Millstone-1. It was determined that ventilation was not required for systems during accident conditions and ventilation systems were not modeled for the Millstone-1 IREP study. The conclusions of the IREP study team with regard to the individual points brought out by this issue are as follows:

a. The standby gas treatment system (SGTS) serves only to enhance habitability in internal plant areas (but outside the control room). The inability of the SGTS to provide ventilation will not affect equipment operability. Regarding plant habitability, SGTS failure may make operator access to certain areas difficult. However, the IREP actions in the plant which were significant to risk reduction would have to be performed before serious core damage/core melt had occurred. Radiation levels would be low at this time, even without the SGTS. Once serious core damage/core melt had occurred and radiation levels increased, there were no actions which could be performed that would require operator access to the high radiation areas. Thus SGTS does not serve to reduce core melt frequency or risk.

b. The LPCI and core spray systems do not require ventilation in order to function. This was substantiated by the results of tests performed by General Electric on April 23, 1970 and documented in GE Letter MS-2320, May 2, 1970, on the subject of "Emergency Core Cooling System Corner Room Heatup Test." The document stated that the ECCS pumps were operated under accident conditions continuously for 36 hours without ventilation. The summary of results for the pumps are as follows:

Location	Maximum Allowable Temperature	Actual Maximum Temperature During Test
Room Ambient	165°F	90°F
CS Pump Motor Outlet	220°F	128°F
LPCI Pump Motor Outlet	266°F	119°F

It is obvious that the pumps were never in danger of overheating. Since ventilation is not required for system success, any modifications to the ventilation of these pumps would not affect system unavailability.

c. The FWCI, TBSCCW, and Auxiliary Electrical Equipment do not require ventilation to function. This is because the heat producing components of these systems are not actually located in rooms, but are located on the open decks of the turbine building where free air connection is possible. These components are cooled during normal operation more by convection than by forced ventilation, although air exchange is provided throughout the turbine building by the ventilation. It was the judgment of the Millstone-1 IREP study team, after a tour of the plant, that the large volume of the turbine building and the possibility of free convection was sufficient justification to conclude that ventilation was not required for system function (especially considering that most equipment in the building would not be operating during accident conditions, reducing the heat load). Additionally, the tests on the LPCI and CS pumps in the corner room heatup referred to above support this conclusion. Since ventilation is not required for system success, any modifications to the ventilation of these systems would not affect system unavailability.

d. The ESW and SWS do not require ventilation in order to function. This is because the heat producing components of these systems are located in an intake structure external to the main plant buildings. Ample convection and air circulation is present in this structure. Additionally, no heat is added to the building by heating up of the working fluid during accident conditions since these are open systems taking cool water directly from the ultimate heat sink. Thus there is no reason to believe that the conditions in the intake structure would be even equal to those for the LPCI and CS pumps. Thus the conclusions are the same.

e. Station batteries do require ventilation to be ensured of safe, continuous operation. It was determined during the IREP study, however, that the batteries would be able to perform necessary functions before failure under any condition where they were needed. This was based on the following evaluations:

   1. If the ac chargers are available, it does not matter if the batterires failed since the chargers can supply all required dc power.

   2. If all ac power (normal and emergency) is lost for a short time (<1/2 hour), the batteries would be able to function over this time period to establish emergency functions (including chargers).

   3. If all ac power is lost for an extended period of time, there are no additional functions which could be performed by the batteries alone which would affect plant status. If offsite power were eventually reestablished dc power would be reenergized, through the chargers, rendering the condition of the batteries moot.

   Thus the presence of ventilation for the batteries would have no effect on risk.

f. The diesel generator does not need room ventilation to function. The design of the diesel generator is such that sufficient cooling is provided by the direct cooling of the diesel heat exchangers by the service water system and the fact that hot combustion air is exhausted outside the room. Conversely, in the absence of service water cooling, the diesel will not function even if ventilation is available. The only concern which was considered further was that, for this room, the habitability would be seriously degraded by the lack of ventilation. This was eventually discarded since the habitability problem would only be present if the diesel were operating, in which case there would be no need to enter the room. Conversely, if there was a need to enter the room, this would imply the diesel was inoperative, and thus no habitability problem would exist.

As stated at the beginning of this section, these were the conclusion of the Millstone-1 IREP team with regard to ventilation requirements at Millstone-1. The result of this was that ventilation was considered to be unneccesary at Millstone and would not impact the system failures. Thus ventilation was not considered to be a support system during the accidents analyzed for the study, and detailed models were not constructed. No further analysis of this issue need be performed.

5. Analysis

None required.

6. Conclusions

Since the Millstone-1 IREP study concluded that ventilation systems were not important, the importance of this issue to core melt frequency is negligible.

XV-1. Decrease in Feedwater Temperature, Increase in Feedwater Flow, and Increase in Steam Flow

1. NRC Evaluation

Failure of the feedwater controller to maximum demand results in an increase in reactor power and vessel inventory. A feedwater control failure at rated power is similar to the turbine trip event at rated power with the turbine bypass operable. However, for the feedwater controller event, the turbine trip signal occurs when the reactor is at above rated power. Hence, this event can be limiting with respect to minimum critical power and is evaluated in reload analysis. To meet current criteria, surveillance of the turbine bypass system is required. Since the bypass system was assumed to operate in the analysis of this event, limitations to either reactor power or minimum critical power ratio would be required in the Technical Specifications to cover the case where the bypass system is found inoperable.

2. NRC Recommendations

Perform surveillance of the turbine bypass system and write limitations to either reactor power or the minimum critical power ratio in the Technical Specifications to cover the case where the bypass system is found inoperable.

3. System Affected

This event is a transient initiating event for core melt sequences.

4. Comments

This event had been considered when performing the analysis of initiating events in the Millstone-1 IREP PRA. That analysis applies directly here.

5. Analysis

The risk significance of <u>any</u> transient with the turbine bypass unavailable is that this makes the power conversion system (PCS) unavailable as a system to be used for heat removal during the transient. The transient initiators in the Millstone-1 IREP Study were grouped according to whether the PCS was available since that was the only mitigating system found to be affected by transients. The transients studied were those identified in the document EPRI NP-801 and a failure modes and effects analysis (FMEA) of postulated transient initiators in support systems.

The specific case of a transient with the turbine bypass unavailable was treated as a transient with <u>subsequent</u> loss of the power conversion system. One reason for loss of the power conversion system is turbine bypass failure, so including these transients with transients causing loss of the PCS would result in double-counting these transients.

The Millstone-1 transient frequency with loss of the PCS (initially or subsequently) is 2.14/yr, dominated by MSIV closure, loss of condenser vacuum, increasing feedwater flow, and pressure regulator failing open. Note that increasing feedwater flow causes loss of the PCS independently of turbine bypass failure. However, as stated above, the risk significance of this issue extends beyond this one transient. The key point is that transients involving turbine bypass failure do not contribute to loss of the PCS.

This analysis shows that the historical rate of turbine bypass unavailability has been small enough compared to other causes of loss of the PCS that even if the proposed limitations on reactor operation with the turbine bypass unavailable prevented transients under that condition, the effect on the overall transient rate with loss of the PCS would be negligible.

6. Conclusion

Requiring limitations on reactor operation with the turbine bypass unavailable would have no effect on risk because loss of the turbine bypass does not significantly contribute to the unavailability of the power conversion system compared to other causes.

XV-3 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed)

1. NRC Evaluation

10 CFR Part 50 (GDC 10, 15) requires that the plant should be able to respond to a loss of external load in such a way that the criteria regarding fuel damage and system pressure are met. At Millstone-1, the maximum MCPR (minimum critical power ratio) was calculated based upon an initial power level of 100 percent. Current criteria require that the initial power level be taken as 100 percent power plus an allowance of 2 percent to account for power measurement uncertainties. The higher actual power level could lead to MCPR less than the safety limit.

2. NRC Recommendation

Recalculate the maximum MCPR based on 102 percent initial power level.

3. System Affected

This issue could (possibly) affect offsite doses through minor fuel damage from loss of external load.

4. Comments

None.

5. Analysis

PRAs have shown that the overwhelmingly dominant portion of the risk from nuclear power plants is from core melt accidents. The contribution from small dose releases is negligible. This issue does not affect any Millstone-1 IREP accident sequences because, although loss of external load is a transient initiating event, resolution of the concern would not affect the transient frequency.

6. Conclusion

This issue has no effect on core melt frequency or risk.

XV-18 Radiological Consequences of a Main Steam Line Failure Outside Containment

1. NRC Evaluation

This issue addresses exceeding 10 CFR Part 100 doses during an event which does not lead to core melt.

2. NRC Recommendations

Make whatever changes necessary to prevent exceeding 10 CFR Part 100 doses.

3. Systems Affected

This issue affects offsite consequences.

4. Comments

None.

5. Analysis

PRAs have shown that the overwhelmingly dominant portion of the risk from nuclear power plants is from core melt accidents. The contribution from rod ejection, spent fuel pool accidents, transportation accidents, and other small dose releases is negligible compared to the massive releases of radioactive material from core melt accidents. Thus the effect on risk of resolving this issue is negligible.

6. Conclusions

This issue has no effect on core melt frequency or risk.

APPENDIX E

REFERENCES TO CORRESPONDENCE FOR EACH TOPIC EVALUATED

SEP Topic No.	Date	Reference
II-1.A	7/31/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic II-1.A, Exclusion Area Authority and Control.
II-1.B	11/27/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics II-1.B, Population Distribution, and III-4.D, Site Proximity Missiles.
II-1.C	8/4/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic II-1.C, Potential Hazards due to Nearby Industrial, Transportation and Military Facilities.
II-2.A	3/30/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic II-2.A, Severe Weather Phenomena.
II-2.C	12/23/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic II-2.C, "Atmospheric Transport and Diffusion Characteristics for Accident Analysis."
II-3.A	6/30/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics II-3.A, Hydrologic Description; II-3.B, Flooding Potential and Protection Requirements; II-3.B.1, Capability of Operating Plants To Cope With Design Basis Flooding Conditions; and II-3.C, Safety-Related Water Supply (Ultimate Heat Sink).
II-3.B	6/30/82	See reference for Topic II-3.A.
II-3.B.1	6/30/82	See reference for Topic II-3.A.
II-3.C	6/30/82	See reference for Topic II-3.A.
II-4	5/11/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topics II-4, Geology and Seismology, and II-4.B, Proximity of Capable Tectonic Structures in Plant Vicinity.
II-4.A	6/8/81	Letter from D. M. Crutchfield (NRC) to all SEP owners, Subject: Site Specific Ground Response Spectra for SEP Plants Located in the Eastern United States.
II-4.B	5/11/82	See reference for Topic II-4.
II-4.C	6/8/81	See reference for Topic II-4.A.

SEP Topic No.	Date	Reference
II-4.D	6/30/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics II-4.D, Stability of Slopes.
II-4.F	6/15/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic II-4.F, Settlement of Foundations and Buried Equipment.
III-1	9/16/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics III-1, V-11.B, and VII-3, Millstone 1 Nuclear Power Plant.
	5/5/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-1, Quality Group Classification of Components and Systems.
III-2	9/30/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-2, "Wind and Tornado Loadings."
III-3.A	9/15/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-3.A, Effects of High Water Level on Structures.
III-3.C	6/23/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-3.C, Inservice Inspection of Water Control Structures.
III-4.A	5/25/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-4.A, "Tornado Missiles."
III-4.B	6/29/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-4.B, Turbine Missiles.
III-4.C	6/9/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Systematic Evaluation Program III-4.C, "Internally Generated Missiles."
III-4.D	11/27/81	See reference for Topic II-1.B.
III-5.A	6/24/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-5.A, Effects of Pipe Break on Structures, Systems and Components Inside Containment.
III-5.B	9/28/81	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-5.B, Pipe Break Outside Containment.

SEP Topic No.	Date	Reference
III-6	6/30/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Safety Topics III-6, Seismic Design Consideration, and III-11, Component Integrity - Ginna Nuclear Power Plant.
III-7.B	8/11/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topic III-7.B, "Design Codes, Design Criteria and Load Combinations."
III-7.D	2/17/81	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topic III-7.D, Containment Structural Integrity Test.
III-8.A	7/6/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: Systematic Evaluation Program Topic III-8.A, Loose Parts Monitoring and Core Barrel Vibration Program.
III-8.C	6/24/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic III-8.C, Irradiation Damage, Use of Sensitized Stainless Steel and Fatigue Resistance.
III-10.A	4/12/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics III-10.A, Thermal Overload Protection for Motors of Motor Operated Valves, Safety Evaluation Report.
III-10.C	8/29/79	Letter from W. G. Counsil (NNECo) to D. L. Ziemann (NRC), Subject: SEP Topic III-10.C, BWR Recirculation Pump Discharge Valves.
IV-1.A	2/12/79	Letter from W. G. Counsil (NNECo) to D. L. Ziemann (NRC), Subject: SEP Topic IV-1.A - (N-1) Loop Operation.
IV-2	10/14/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topic IV-2, Reactivity Control System.
IV-3	4/13/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topic IV-3, BWR Jet Pump Operating Indications.
V-5	8/28/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic V-5, Reactor Coolant Pressure Boundary Leakage Detection.
V-6	9/29/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Completion of SEP Topic V-6, Reactor Vessel Integrity.

SEP Topic No.	Date	Reference
V-10.A	3/5/79	Letter from W. G. Counsil (NNECo) to D. L. Ziemann (NRC), Subject: SEP Topic V-10.A, Residual Heat Removal System Heat Exchanger Tube Failure.
V-10.B	7/22/81	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topics V-10.B, RHR System Reliability; V-11.B, RHR Interlock Requirements; and VII-3, Systems Required for Safe Shutdown (Safe Shutdown Systems Report).
V-11.A	7/8/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic V-11.A, Requirements for Isolation of High and Low Pressure Systems Revised Safety Evaluation for Millstone 1.
V-11.B	2/1/82	Letter from D. M. Crutchfield (NRC) W. G. Counsil (NNECo), Subject: SEP Topic V-11.B, RHR Interlock Requirements.
	7/22/81	See reference for Topic V-10.B.
V-12.A	12/17/79	Letter from D. L. Ziemann (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic V-12.A, Water Purity of BWR Primary Coolant.
VI-1	2/26/82	Letter from J. Shea (NRC) to W. C[illegible] (NNECo), Subject: SEP Topic VI-1, Organic [illegible] and Post Accident Chemistry.
VI-2.D	9/15/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Systematic Evaluation Program (SEP) Evaluation Report on Topics VI-2.D and VI-3.
VI-3	9/13/82	See reference for Topic VI-2.D.
VI-4	8/12/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: Containment Isolation System (Electrical).
VI-4	10/8/82	Letter from J. J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Forwarding Final Evaluation Report of SEP Topic VI-4, Containment Isolation System (Systems).
VI-6	10/22/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: Completion of Appendix J Review.
VI-7.A.3	10/27/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: Topic VI-7.A.3, ECCS Actuation System.

SEP Topic No.	Date	Reference
VI-7.A.4	3/11/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VI-7.A.4, Core Spray Nozzle Effectiveness.
VI-7.C	3/29/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics VI-7.C, ECCS Single Failure Criterion and Requirements for Locking Out Power to Valves, and VI-7.C.2, Failure Mode Analysis.
VI-7.C.1	11/2/81	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topic VI-7.C.1, Appendix K - Electrical Instrumentation and Control (EI&C) Re-Reviews, Safety Evaluation.
VI-7.C.2	3/29/81	See reference for Topic VI-7.C.
VI-7.D	8/17/78	Letter from D. G. Eisenhut (NRC) to W. G. Counsil (NNECo), Subject: Evaluation of Eight SEP Topics.
VI-10.A	10/8/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VI-10.A, Testing of Reactor Trip System and Engineered Safety Features, Including Response Time Testing.
VI-10.B	8/5/81	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topic VI-10.B, Shared Systems for Multi-Unit Stations.
VII-1.A	7/23/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VII-1.A, Engineered Safety Features (ESF) System Control Logic and Design.
VII-1.B	8/17/78	See reference for Topic VI-7.D.
VII-2	6/25/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VII-2, Engineered Safety Feature System Control Logic and Design, Safety Evaluation.
VII-3	7/22/81	See reference for Topic V-10.B.
	2/1/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VII-3, Systems Required for Safe Shutdown (EICS Matters), Safety Evaluation Report.
VII-6	8/28/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VII-6, Frequency Decay.

SEP Topic No.	Date	Reference
VIII-1.A	6/30/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VIII-1.A, Potential Equipment Failures Associated With Degraded Grid Voltage.
VIII-2	9/30/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VIII-2, Onsite Emergency Power System.
VIII-3.A	8/26/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VIII-3.A, Station Battery Capacity Test Requirement.
VIII-3.B	7/23/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VIII-3.B, DC Power System Bus Voltage Monitoring and Annunciation, Safety Evaluation.
VIII-4	7/7/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic VIII-4, Electrical Penetrations of Reactor Containment Safety Evaluation Report.
IX-1	3/9/82	Letter from to J. Shea (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic IX-1, Fuel Storage.
IX-3	7/6/82	Letter from W. G. Counsil (NNECo), to D. M. Crutchfield (NRC), Subject: SEP Topic IX-3, Station Service and Cooling Water System.
IX-5	9/14/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Forwarding Final Evaluation Report of SEP Topic IX-5, Ventilation Systems.
IX-6	6/15/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Fire Protection Rule - 10 CFR 50.48(c)(5) - Alternative Safe Shutdown - Section III.G.3 of Appendix R to 10 CFR 50 - (SEP Topic IX-6).
XIII-2	6/9/82	Letter from J. Shea (NRC) to W. G. Counsil (NNECo), Subject: Amendment No. 59, 82.
XV-1	12/31/81	Letter from D. M. Crutchfield, (NRC) to W. G. Counsil (NNECo) Subject: SEP Topic XV-1, Design Basis Event Accidents and Transients.

SEP Topic No.	Date	Reference
XV-3	9/18/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics XV-3, Loss of External Load, Turbine Trips, Loss of Condenser Vacuum, Closure of Main Steam Isolation Valve (BWR), and Steam Pressure Regulator Failure (Closed); XV-4, Loss of Non-Emergency AC Power to the Station Auxiliaries; and XV-14, Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction That Increases Reactor Coolant Inventory.
XV-4	9/18/81	See reference for Topic XV-3.
XV-5	1/7/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-5, Loss of Normal Feedwater Flow.
XV-7	12/4/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-7, Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break.
XV-8	8/26/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topics XV-8, Control Rod Misoperation and XV-19, Loss of Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary (Systems).
XV-9	1/12/82	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-9, Startup of an Inactive Loop.
XV-11	10/14/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-11, Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position.
XV-13	1/13/82	Letter from W. G. Counsil (NNECo) to D. M. Crutchfield (NRC), Subject: SEP Topics XV-13, Spectrum of Rod Drop Accidents, XV-19, Loss of Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary, and XV-20, Radiological Consequences of Fuel Damaging Accidents (Doses).
XV-13	9/9/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-13, Spectrum of Rod Drop Accidents (Systems).

SEP Topic No.	Date	Reference
XV-14	9/13/81	See reference for Topic XV-3.
XV-15	10/28/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-15, Inadvertent Opening of a PWR Pressurizer Safety/Relief Value or a BWR Safety/Relief Valve.
XV-16	11/3/81	See reference for Topic XV-13.
XV-18	11/3/81	Letter from D. M. Crutchfield (NRC) to W. G. Counsil (NNECo), Subject: SEP Topic XV-18, Radiological Consequences of Main Steam Line Failure Outside Containment.
XV-19	8/26/81	See reference for Topic XV-8.
	11/3/81	See reference for Topic XV-13.
XV-20	11/3/81	See reference for Topic XV-13.
XVII	8/17/78	See reference for Topic VI-7.D.

APPENDIX F

REVIEW OF OPERATING EXPERIENCE FOR
MILLSTONE NUCLEAR GENERATING STATION, UNIT 1

Contract No. W-7405-eng-26

Nuclear Safety Information Center

Engineering Technology Division

REVIEW OF THE OPERATING EXPERIENCE HISTORY OF MILLSTONE 1 THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

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CONTENTS

Page

LIST OF TABLES

LIST OF FIGURES

REVIEW OF THE OPERATING HISTORY OF MILLSTONE UNIT 1 THROUGH 1981

EXECUTIVE SUMMARY

The Systematic Evaluation Program Branch of the Nuclear Regulatory Commission (NRC) is conducting the Systematic Evaluation Program (SEP) for the purpose of determining the safety margins of the design and operation of ten of the older operating commercial nuclear power plants in the United States. These ten plants are being reevaluated in terms of present NRC licensing requirements and regulations. Thus, the SEP is intended:

1. to establish documentation that shows how these ten plants compare with current acceptance criteria and guidelines on significant safety issues and to provide a technical rationale for acceptable departures from these criteria and guidelines,

2. to provide the capability for making integrated and balanced decisions with respect to any required backfitting, and

3. to provide for the early identification and resolution of any potential safety deficiency.

The SEP evaluates specific safety topics based on an integrated review of the overall ability of a plant to respond to certain design-basis events including normal operation, transients, and postulated accidents.

As part of the SEP, the NRC contracted with the Oak Ridge National Laboratory to perform operating history reviews. These reviews are intended to augment the SEP's safety topic review and to aid in the determination of priorities for required backfitting during the integrated assessment. Each review includes collection and evaluation of availability and capacity factors, forced shutdowns, forced power reductions, reportable events, environmental events, and radiological release events.

This summary presents the results from the review of the operating experience of the Millstone Unit 1 Nuclear Power Plant which is a General Electric-designed boiling-water reactor, owned and operated by Northeast Nuclear Energy Company. The plant is located in Waterford, Connecticut. The reactor has a licensed thermal power of 2011 MWt and a design electric rating of 660 MWe. Millstone 1 achieved initial criticality on October 26, 1970 and began commercial operation in December 1970.

From 1971 through 1981, the reactor availability factor at Millstone averaged 76.1%, and the unit capacity factor averaged 61.6%. The cumulative values were 77.1% and 64.4%, respectively, both of which are above average for commercial nuclear power plants. The reactor availability factor fell below 70% in only two years, 1973 and 1981. The major unit shutdowns in 1973 were for refueling and for feedwater sparger replacement. These two shutdowns combined for over five months of downtime. In 1981, two shutdowns, for refueling and for balancing of the turbine, again combined for over five months of downtime.

The operating history review focused on data evaluation which was divided into two segments: (1) evaluation of forced shutdowns and power reductions and (2) evaluation of reportable events. Design basis events (DBEs), which are defined in the NRC's *Standard Review Plan*,[1] are failures that initiate system transients and challenge engineered safety features. In the forced shutdown and power reduction segment, the review identified DBEs and recurring events that might indicate a potential operating concern. In the reportable event segment which included environmental events and radiological release events, the review identified significant events and recurring events that might indicate a potential operating concern. Significant events were either DBEs or events with a loss of engineered safety function.

Forced Shutdowns and Power Reductions

Of the 172 forced shutdowns and power reductions between 1971 and 1981 at Millstone 1, 54 were DBEs of 1 of the 11 following types:

1. turbine trip (33),
2. steam pressure regulator failure resulting in increased steam flow (3),
3. steam pressure regulator failure resulting in decreased steam flow (3),
4. loss of normal feedwater (3),
5. inadvertent opening of a safety or relief valve (3),
6. increased feedwater flow (2),
7. loss of external electric load (2),
8. inadvertent closure of main steam isolation valve (MSIV) (2),
9. decreased feedwater temperature (1),
10. loss of condenser vacuum (1), and
11. reactor recirculation pump trip (1).

Forty-seven of the 54 DBEs were the result of equipment failure. Human error caused the remaining 7 events. In all DBEs, the engineered safety features operated properly to mitigate the transient.

DBEs averaged 5 occurrences per year over the operating history at Millstone 1. The largest number of events in a single year (25) occurred in 1971. Since 1977, the average number of DBEs per year has been about 3. The frequency of occurrence of each type of DBE is consistent with the experience of other plants except for turbine trips. Problems with moisture separator drain tank level control during power changes was the primary cause of turbine trips (21 of 33 events). The level control problem occurred less frequently over time with 14 events in 1971 and 1 event in 1981.

Reportable Events

In the reportable event segment of the operating history review of Millstone 1, 320 events were reviewed. The trend for the number of reportable event reports submitted by Millstone 1 is generally upward with peak years of 1977, 1979, and 1981, with 38, 36, and 44 events, respectively. The causes of reportable events have been primarily inherent equipment failures, which contributed 55% of all reported events. Human error (including administrative, design, fabrication, installation, maintenance, and operator error) caused 44% of the reported events. Other causes, such as adverse environmental conditions, were responsible for the remaining 1%. There is no apparent trend in the causes of reported events.

Of the 320 reported events, 13 are considered significant:

1. loss of the isolation condenser (1),
2. provisions for emergency core cooling during a loss of normal power lost (2),
3. ECCS failures (2),
4. loss of offsite power with partial loss of emergency power (1),
5. complete and potential loss of emergency power (2),
6. inadvertent criticality (1),
7. all control rod drive accumulators require replacement (1),
8. recirculation pumps trip with no alarm given (1),
9. loss of pressure control followed by a blowdown (1), and
10. hydrogen explosion in the off-gas system (1).

The major contributor to the significant events was human error which caused 11 of the 13 events. The remaining 2 events were caused by equipment failures of diesel generator and gas turbine generator components. All but three of the significant events have occurred since 1976.

Failure of the emergency power system was a major cause of significant events. On two occasions in 1976, the gas turbine generator failed in coincidence with the isolation condenser being inoperable. The gas turbine is one of two emergency power supplies at Millstone 1. In the event of a loss of offsite power, the feedwater coolant injection system and one loop of the low-pressure coolant injection and core spray systems would have been lost in addition to the isolation condenser.[2,3] During a loss of offsite power in 1976, the gas turbine again failed to run. The unit's diesel generator was the sole source of ac power.[4] On December 1, 1977, both emergency power sources were lost simultaneously.[5] Two potential emergency power system failures were discovered during design reviews in 1979 and 1981. The possibility existed to lose emergency power to emergency cooling systems by either the failure to sense a power loss or a single relay failure disabling both the gas turbine and diesel generators.[6,7]

Recurring Events

The following five types of recurring events were noted during the two segments of the operating history review:

1. partial loss of emergency power,
2. excessive cooldowns,
3. pipe cracks,
4. isolation condenser valve failures, and
5. MSIV failures.

The emergency power system at Millstone 1 consists of one diesel generator and one gas turbine generator. If normal power to the plant is lost, the gas turbine is the sole power source for the feedwater coolant injection (FWCI) system. The gas turbine generator failed to start or run for its entire mission 28 times. As discussed earlier, many of these failures occurred when redundant power systems or systems redundant to the FWCI system were not operable.

Millstone 1 experienced five excessive thermal transients in eight blowdowns due to safety and relief valve failures. The cooldown rates during the transients ranged from 105°F/h to 450°F/h. The first of these events occurred in 1971. Since 1975, the transients have recurred at a rate greater than one every two years and continues to be an ongoing problem.

Millstone 1 reported eight instances of pipe cracks. Cracks appeared in feedwater spargers, head spray piping, main steam line supports, and condenser nozzles. Pipe cracking found at Millstone is typical of the generic problems found in many BWRs.

A variety of problems caused nine isolation condenser failures between 1970 and 1979. In seven of the nine events, a supply valve opened too wide, or failed to open, and caused an isolation condenser system failure. On one occasion, a valve transferred open and initiated the isolation condenser system. The final event occurred because a return valve failed to close. The problems with the isolation condenser valves appear to have been solved, since the last reported occurrence was September 4, 1979.

There were 10 failures of the main steam isolation valves (MSIVs). The predominate cause for MSIV failures involved poor quality control air to the pilot valves. This failure mechanism has the potential to affect more than one MSIV at a time. The last actual MSIV failure occurred in 1974.

Conclusions

For this analysis of the operating history at Millstone 1, 172 shutdowns and power reductions were reviewed along with 320 reportable events and other miscellaneous documentation concerning the operation of the Millstone Unit 1 Nuclear Power Plant. The objective was to identify those areas of plant operation that have compromised plant safety. This review identified no significant challenges to plant safety. However, Millstone 1 has and is experiencing many of the generic problems of nuclear power plants in general and BWRs specifically. Two of the problems which should be of continued concern are emergency power system failures and incidents resulting in excessive cooldown rates because of safety and relief valve failures.

On many occasions, the emergency power system (specifically the gas turbine generator) was unavailable when needed. The Millstone Station is physically located on a point, and all offsite power lines must share the same right-of-way for several miles. This increases the probability of losing all offsite power due to common cause failure and increases the importance of the onsite emergency power source.

Excessive cooldown rates are of concern because of the thermal stress placed upon the reactor vessel and coolant piping. It is additionally important because the resulting effect of fatigue is cumulative. The number of excessive cooldowns experienced at Millstone 1 is greater than the number of similar events found in other SEP operational reviews. Because of the cumulative effect and the increased recurrence rate, the problem of excessive cooldown rates due to safety and relief valve failures should also be of continued concern.

References

1. Nuclear Regulatory Commission, "Accident Analysis for the Review of Safety Analysis Reports for Nuclear Power Plants," Chap. 15 of *Standard Review Plan*. NUREG-0800 (July 1981).

2. Letter from F. W. Hartley, Plant Superintendent, Millstone Nuclear Power Station, Northeast Nuclear Energy Company, to James P. O'Reilly, Director, Region 1, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, RO 76-10/1T, March 22, 1976.

3. Letter from F. W. Hartley, Plant Superintendent, Millstone Nuclear Power Station, Northeast Nuclear Energy Company, to James P. O'Reilly, Director, Region 1, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, RO 76-12/1T, March 29, 1976.

4. Letter from F. W. Hartley, Plant Superintendent, Millstone Nuclear Power Station, Northeast Nuclear Energy Company, to James P. O'Reilly, Director, Region 1, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, RO 76-29/1T, August 24, 1976.

5. Letter from E. J. Ferland, Plant Superintendent, Millstone Nuclear Power Station, Northeast Nuclear Energy Company, to Boyce H. Grier, Director, Region 1, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, RO 77-39/1P, December 12, 1977.

6. Letter from J. F. Opeka, Station Superintendent, Millstone Nuclear Power Station, Northeast Utilities, to Boyce H. Grier, Director, Region 1, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, RO 79-26/1T, September 27, 1979.

7. Letter from E. J. Mroczka, Station Superintendent, Northeast Nuclear Energy Company, Northeast Utilities, to Boyce H. Grier, Director, Region 1, Office of Inspection and Enforcement, U.S. Nuclear Regulatory Commission, LER RO 81-02/1T, April 20, 1981.

ABSTRACT

A review of the operating experience of Millstone 1 nuclear power plant through 1981 was performed by the staff of the Nuclear Safety Information Center for the Nuclear Regulatory Commission's Systematic Evaluation Program (SEP). Under the Commission's SEP Program the safety margins of the design and operation of the eleven oldest operating commercial nuclear power plants in the United States are being reevaluated.

The review of the operating experience for each plant included data collection and evaluation of availability and capacity factors, forced shutdowns, power reductions, reportable events (reportable occurrence, licensee event reports, etc.), and environmental considerations. As well, the review methodology and procedures as used in the review and evaluation are discussed. Data and information collected for forced shutdowns, power reductions, and reportable events are presented in appendices.

REVIEW OF THE OPERATING EXPERIENCE HISTORY OF MILLSTONE 1 THROUGH 1981 FOR THE NUCLEAR REGULATORY COMMISSION'S SYSTEMATIC EVALUATION PROGRAM

1. SCOPE OF REVIEW

The assessment of the operating experience review for Millstone 1 covered the time from initial criticality through 1981. The data collection and evaluation included the following aspects of operation: availability and capacity factors, forced shutdowns and power reductions, reportable events, events of environmental importance and radioactivity releases, and evaluation of the operating experience in total. Tables at the end of Chap. 1 show the codes assigned to operational aspects of forced shutdowns, power reductions, and reportable events. These codes are used in the reporting of data collected during the review of operating experience.

1.1 Availability and Capacity Factors

Both reactor and unit availability factors were compiled for all years. Starting with 1974, the unit capacity factors using the design electrical rating (DER) in net megawatts (electric) and the maximum dependable capacity (MDC) in net megawatts (electric) were compiled as well. Data for the capacity factors were not available from earlier years.

The two availability and two capacity factors are defined as follows:

1. reactor availability =

$$\frac{\text{hours reactor critical + reactor reserve shutdown hours}}{\text{period hours}}$$

2. unit availability =

$$\frac{\text{hours generator on line + unit reserve shutdown hours}}{\text{period hours}}$$

3. $$\text{unit capacity (DER)} = \frac{\text{net electrical energy generated}}{\text{period hours x DER net}} \times 100\ ,$$

4. $$\text{unit capacity (MDC)} = \frac{\text{net electrical energy generated}}{\text{period hours x MDC net}} \times 100\ .$$

Reserve shutdown hours are the amounts of time the reactor is not critical or the unit is shutdown for administrative or other similar reasons when operation could have been continued.

1.2 Review of Forced Shutdowns and Power Reductions

Forced shutdowns and power reductions were reviewed, and data were collected on each incident. Scheduled shutdowns for refueling and maintenance were not included in the review. However, if a utility had a refueling outage scheduled, the plant experienced a shutdown as a result of an abnormal event prior to the scheduled refueling, the utility reported that the refueling was being rescheduled to coincide with the current shutdown, and the utility reported the cause of the shutdown as refueling, then this shutdown was considered as forced. Only that portion of the outage time concerned with the abnormal event, not the refueling time, was included in the compilations.

The power reductions were included to provide information and details that may have been associated with a previous or subsequent shutdown. The power reductions are included in the proper chronological sequence with the shutdowns in the data tables for the forced shutdowns and power reductions (see Appendixes).

The following data were compiled annually for the forced shutdowns and power reductions:

1. date of occurrence,
2. duration (hours),
3. power level (percent),
4. notation of whether the shutdowns were also reportable events [e.g., a licensee event report (LER) or abnormal occurrence report (AOR)],
5. summary description of events associated with the forced shutdown or power reduction,
6. cause of shutdown (Table 1.1),
7. method of shutdown (Table 1.1),
8. system taken from NUREG-0161 (Ref. 1) that was directly involved with the shutdown or power reduction (Table 1.2),
9. component directly involved with the shutdown or power reduction (Table 1.3), and
10. categorization of the shutdown or power reduction.

Each shutdown or power reduction was placed in one of two sets of significance categories. The shutdowns and power reductions were first evaluated against criteria for DBEs as described in Chap. 15 of the *Standard Review Plan*.[2] If the shutdown or power reduction could not be categorized as a design-basis initiating event, then it was placed in one of a series of Nuclear Safety Information Center (NSIC) categories. For further discussions of the two sets of significance categories, use of the categories, and a listing of them, see Sect. 3.1.

The listings for the cause, shutdown method, system involved, and component involved along with their respective codes are those used in the NUREG-0020 series[3] ("Gray Books") on shutdowns. Note that the information listed under the "System involved" column in the data tables in the appendixes indicates (1) a general classification of systems (fully written out) and (2) a specific system, which is coded with two letters, within the general classification.

1.3 Review of Reportable Events

The operating events as reported in LERs and LER predecessors [e.g., abnormal occurrence reports (AORs*), unusual event reports, reportable occurrences (ROs)] were reviewed. These types of reportable events were retrieved from the NSIC computer file. Approximately six years ago, operating experience information for operating nuclear power plants was input to the NSIC file for the period of time before LERs was reviewed. Any documents that contained LER-type information (such as equipment failures or abnormal events) were coded or indexed so that they could be retrieved in the same manner as an LER. Primarily, this involved various types of operating reports and general correspondence for the late 1960s and early 1970s.

The following information was recorded for each reportable event reviewed:

1. LER number or other means of identification of report type,
2. NSIC accession number (a unique identification number assigned to each document entered into the NSIC computer file),
3. date of the event,
4. date of the report or letter transmitting the event description,
5. status of the plant at the time of the occurrence (Table 1.4).
6. system involved with the reportable event (Table 1.2),
7. type of equipment involved with the reportable event (Table 1.5),
8. type of instrument involved with the reportable event (Table 1.5),
9. status of the component (equipment) at the time of the occurrence (Table 1.4),
10. abnormal condition associated with the reportable event (e.g., corrosion, vibration, leak) (Table 1.6),
11. cause of the reportable event (Table 1.4), and
12. significance of the reportable event.

As a step in the evaluation process, each reportable event was screened using the criteria further discussed in Sect. 3.2.

Note that in the tables of reportable events in Appendix A for Yankee Rowe, comments and/or details on the events were included.

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*The AO designation used by some utilities for identifying operational events during a particular time frame is <u>not</u> to be confused with those safety-significant events listed in the <u>Report to Congress on Abnormal Occurrences</u> (NUREG-0090 series) which also uses the AO designation.

1.4 Events of Environmental Importance and Releases of Radioactivity

Any significant or recurring environmental problems were summarized based on the review of forced shutdowns, power reductions, reportable events (environmental LERs), and operating reports. Routine radioactivity releases were tabulated as well, and releases where limits were exceeded were reviewed and are discussed in Sect. 4.5.1.4.

1.5 Evaluation of Operating Experience

The operating history of the plants was evaluated based on a review that involved screening, categorizing, and compiling data. Judgments and conclusions were made regarding safety problems, operations, trends (recurring problems), or potential safety concerns. Events were analyzed to determine their safety significance from the information provided through the various operating reports and the review process. The final safety analysis reports provided specific plant and equipment details when necessary.

Table 1.1. Codes and causes of forced shutdown or power reduction and methods of shutdown

	Causes
A	Equipment failure
B	Maintenance or testing
C	Refueling
D	Regulatory restriction
E	Operator training and license exams
F	Administrative
G	Operational error
H	Other
	Methods
1	Manual
2	Manual scram
3	Automatic scram
4	Continuation
5	Load reduction
9	Other

Table 1.2. Codes and systems involved with the forced shutdown, power reduction, or reportable event

System	Code
Reactor	RX
Reactor vessel internals	RA
Reactivity control systems	RB
Reactor core	RC
Reactor coolant and connected systems	CX
Reactor vessels and appurtenances	CA
Coolant recirculation systems and controls	CB
Main steam systems and controls	CC
Main steam isolation systems and controls	CD
Reactor core isolation cooling systems and controls	CE
Residual heat removal systems and controls	CF
Reactor coolant cleanup systems and controls	CG
Feedwater systems and controls	CH
Reactor coolant pressure boundary leakage detection systems	CI
Other coolant subsystems and their controls	CJ
Engineered safety features	SX
Reactor containment systems	SA
Containment heat removal systems and controls	SB
Containment air purification and cleanup systems and controls	SC
Containment isolation systems and controls	SD
Containment combustible control systems and controls	SE
Emergency core cooling systems and controls	SF
Core reflooding system	SF-A
Low-pressure safety injection system and controls	SF-B
High-pressure safety injection system and controls	SF-C
Core spray system and controls	SF-D
Control room habitability systems and controls	SG
Other engineered safety feature systems and their controls	SH
Containment purge system and controls	SH-A
Containment spray system and controls	SH-B
Auxiliary feedwater system and controls	SH-C
Standby gas treatment systems and controls	SH-D
Instrumentation and controls	IX
Reactor trip systems	IA
Engineered safety feature instrument systems	IB
Systems required for safe shutdown	IC
Safety-related display instrumentation	ID
Other instrument systems required for safety	IE
Other instrument systems not required for safety	IF

Table 1.2 (continued)

System	Code
Electric power systems	EX
Offsite power systems and controls	EA
AC onsite power systems and controls	EB
DC onsite power systems and controls	EC
Onsite power systems and controls (composite ac and dc)	ED
Emergency generator systems and controls	EE
Emergency lighting systems and controls	EF
Other electric power systems and controls	EG
Fuel storage and handling systems	FX
New fuel storage facilities	FA
Spent-fuel storage facilities	FB
Spent-fuel pool cooling and cleanup systems and controls	FC
Fuel handling systems	FD
Auxiliary water systems	WX
Station service water systems and controls	WA
Cooling systems for reactor auxiliaries and controls	WB
Demineralized water makeup systems and controls	WC
Potable and sanitary water systems and controls	WD
Ultimate heat sink facilities	WE
Condensate storage facilities	WF
Other auxiliary water systems and controls	WG
Auxiliary process systems	PX
Compressed air systems and controls	PA
Process sampling systems	PB
Chemical, volume control, and liquid poison systems and controls	PC
Failed-fuel detection systems	PD
Other auxiliary process systems and controls	PE
Other auxiliary systems	AX
Air conditioning, heating, cooling, and ventilation systems and controls	AA
Fire protection systems and controls	AB
Communication systems	AC
Other auxiliary systems and controls	AD
Steam and power conversion systems	HX
Turbine-generators and controls	HA
Main steam supply systems and controls (other than CC)	HB
Main condenser systems and controls	HC
Turbine gland sealing systems and controls	HD
Turbine bypass systems and controls	HE
Circulating water systems and controls	HF

Table 1.2 (continued)

System	Cod
Condensate cleanup systems and controls	HG
Condensate and feedwater systems and controls (other than CH)	HH
Steam generator blowdown systems and controls	HI
Other features of steam and power conversion systems (not included elsewhere)	HJ
Radioactive waste management systems	MX
Liquid radioactive waste management systems	MA
Gaseous radioactive waste management systems	MB
Process and effluent radiological monitoring systems	MC
Solid radioactive waste management systems	MD
Radiation protection systems	BX
Area monitoring systems	BA
Airborne radioactivity monitoring systems	BB
Other	XX
Not applicable	ZZ

Table 1.3. Components involved with the forced shutdown or power reduction

Component type	Including
Accumulators	Scram accumulators Safety injection tanks Surge tanks
Air dryers	
Annunciator modules	Alarms Bells Buzzers Claxons Horns Gongs Sirens
Batteries and chargers	Chargers Dry cells Wet cells Storage cells
Blowers	Compressors Gas circulators Fans Ventilators
Circuit closers/interruptors	Circuit breakers Contactors Controllers Starters Switches (other than sensors) Switchgear
Control rods	Poison curtains
Control rod drive mechanisms	
Demineralizers	Ion exchangers
Electrical conductors	Bus Cable Wire
Engines, internal combustion	Butane engines Diesel engines Gasoline engines Natural gas engines Propane engines
Filters	Strainers Screens
Fuel elements	
Generators	Inverters
Heaters, electric	

Table 1.3 (continued)

Component type	Including
Heat exchangers	Condensers Coolers Evaporators Regenerative heat exchangers Steam generators Fan coil units
Instrumentation and controls	
Mechanical function units	Mechanical controllers Governors Gear boxes Varidrives Couplings
Motors	Electric motors Hydraulic motors Pneumatic (air) motors Servo motors
Penetrations, primary containment air locks	
Pipes, fittings	
Pumps	
Recombiners	
Relays	
Shock suppressors and supports	
Transformers	
Turbines	Steam turbines Gas turbines Hydro turbines
Valves	Valves Dampers
Valve operators	
Vessels, pressure	Containment vessels Dry wells Pressure suppression Pressurizers Reactor vessels

Table 1.4. Codes for data collected on plant status, component status, and cause of reportable events

Code	Plant status	Component status	Cause of reportable event
A	Construction	Maintenance and repair	Administrative error
B	Operation	Operation	Design error
C	Refueling	Testing	Fabrication error
D	Shutdown		Inherent error
E			Installation error
F			Lightning
G			Maintenance error
H			Operation error
I			Weather

Table 1.5. Codes for equipment and instruments involved in reportable events

Code		Code	
	Equipment		
A	Accumulator	W	Internal combustion engine
B	Air drier	X	Motor
C	Battery and charger	Y	Nozzle
D	Bearing	Z	Pipe and pipe fitting
E	Blower and dampers	AA	Power supply
F	Breaker	BB	Pressure vessel
G	Cables and connectors	CC	Pressurizer
H	Condenser	DD	Pump
I	Control rod	EE	Recombiner
J	Control rod drive	FF	Seal
K	Cooling tower	GG	Shock absorber
L	Crane	HH	Solenoid
M	Demineralizer	II	Steam generator
N	Diesel generator	JJ	Storage container
O	Fastener	KK	Support structure
P	Filter/screen	LL	Transformer
Q	Flange	MM	Tubing
R	Fuel element	NN	Turbine
S	Fuse	OO	Valve
T	Generator	PP	Valve, check
U	Heat exchanger	QQ	Valve operator
V	Heater		
	Instrumentation		
A	Alarm	L	Power range instrument
B	Amplifier	M	Pressure sensor
C	Electronic function unit	N	Radiation monitor
D	Failed fuel detection instrument	O	Recorder
E	Flow sensor	P	Relay
F	In-core instrument	Q	Seismic instrument
G	Indicator	R	Solid state device
H	Intermediate range instrument	S	Start-up range instrument
I	Level sensor	T	Switch
J	Meteorological instrument	U	Temperature sensor
K	Position instrument		

Table 1.6. Codes used for reportable events — abnormal conditions

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Mechanical

AA Normal wear/aging/end of life: expected effect of normal usage

AB Excessive wear/clearance: component (especially a moving component) experiences excessive wear or too much clearance or gap exists because of overuse, lack of lubrication

AC Deterioration/damage: component is no longer at an acceptable level of quality (e.g., high temperature causes rubber seals to chemically break down or deteriorate, insulation breaks down)

AD Break/shear: structural component physically breaks apart (not when something "breaks down")

AE Warp/bend/deformation: shape of component is physically distorted

AF Collapse: tank or compartment has an external pressure exerted that results in deformation

AG Seize/bind/jam: component has inhibited movement caused by crud, foreign material, mechanical bonding, another component

AH Excessive mechanical loads: mechanical load exceeds design limits

AI Mechanical fatigue: failure due to repeated stress

AJ Impact: the result of the force of one object striking another

AK Improper lubrication: insufficient or incorrect lubrication

AL Missing/loose: component is missing from its proper place or is loose or has undesired free movement

AM Wrong part: incorrect component installed in a piece of equipment

AN Wrong material: incorrect material used during fabrication or installation

AO Weld-related failure: failure caused by defective weld or located in the heat-affected zone

AP Vibration other than flow induced: vibration from any cause other than fluid flow

AQ Crud buildup: buildup of foreign material such as dust, sticks, trash (not corrosion or boron precipitation)

AR Corrosion/oxidation: unanticipated attack

AS Dropped: component is dropped (includes control rod that is "dropped" into core)

AT Leak, internal, within system: leak from one part of a system to another part of the same system

AU Leak, internal, between systems: leak from one system to a different system

AV Crack: defect in a component does not result in a leak through the wall

Table 1.6 (continued)

AW Leak, external: defect in a component results in a leak from the system that is contained in an onsite building

AX Leak to environment: leak not resulting from a cracked or broken component

AY Was opened/transfers open: component is/was opened by error or spuriously opens

AZ Was closed/transferred closed: component is/was wrongly closed by error or spuriously closes

BA Fails to open: component is in the closed state <u>and</u> fails to open on demand (e.g., the circuit breaker "fails to open" when an overcurrent occurs)

BB Fails to close: component is in the open state <u>and</u> fails to close on demand

BC Malposition or maladjustment: component is out of desired position (e.g., normally open valve is closed) or adjusted improperly (not for instrument drift or out of calibration)

BD Failure to start/turn on: component fails to start on demand

BE Stopped/failed to continue to run: component fails to continue running when it has previously started

BF Tripped: component <u>automatically</u> trips on or off (desired or undesired) (e.g., the turbine tripped because of overspeed, the circuit breaker tripped because of overspeed, or the circuit breaker tripped because of overload)

BG Deenergized/power removed: component on system loses its driving potential but not necessarily electrical power [e.g., (1) a fuse blows and there is no power to a sensor, and the sensor is deenergized; (2) a valve closes off the steam supply to a turbine, and the turbine has no driving power]

BH Energized/power applied: component or system gains its driving potential but not necessarily electrical power (e.g., valve is opened allowing steam to turn a turbine)

BI Unacceptable response time: component does not respond to a demand within a desired time frame but does not otherwise fail (e.g., a diesel generator fails to come to full speed within the time constraint)

BJ High pressure: higher than normal or desired pressure exists in a component or system (<u>does</u> <u>not</u> include instrument misindications)

Table 1.6 (continued)

BK Low pressure: lower than normal or desired pressure exists in a component or system (does not include instrument misindication)

BL High temperature: component experiences a higher than normal or desired temperature

BM Low temperature: component (or system) experiences a lower than normal or desired temperature

BN Freezing: fluid medium (e.g., water) freezes in or on a component

BO Excessive thermal cycling: frequent changes in temperature that could result in metal fatigue or cracking

BP Unacceptable heatup/cooldown rate: heatup or cooldown rate exceeds limits

BQ Thermal transient: system experiences an undesired or unstable thermal transient or thermal change

BR Excessive number of pressure cycles: system experiences an undesired number of significant pressure changes (e.g., pressure pulses as from a positive displacement pump)

BS High level/volume: higher than normal or desired level or volume exists (actual or potential) in a component, such as tank or sump, or area, such as auxiliary building (not for instrument misindication)

BT Low level/volume: lower than normal or desired level or volume exists in a component (not for instrument misindication)

BU Abnormal concentration/pH: an abnormal (either high or low) concentration of a chemical or reagent exists in a fluid system or an abnormal pH exists (does not include abnormal boron concentrations)

BV Abnormal boron concentration: process system control rod has an abnormal boron concentration from burnup, dilution, or overaddition

BW Overspeed: speed in excess of design limits

BX Cladding failure: cladding of a component fails (e.g., the cladding of a fuel pellet is breached, and radioactive fuel leaks out)

BY Burning/smoking: component is on fire or smoking

BZ Engaged: component engages or meshes (this is not to be used when a component binds or becomes stuck or jammed)

CA Disengaged/uncoupled: component disengages, loses required friction, or is no longer meshed (as in gears); for example, the clutch on the motor disengages from the shaft (this should not be used for dropped control rods)

Table 1.6 (continued)

Electric/instruments

EA Excessive electrical loads: electrical loads exceed design rating

EB Overvoltage/undercurrent: component failure produces an overvoltage/undercurrent condition other than open circuits

EC Undervoltage/overcurrent: component failure produces an undervoltage/overcurrent condition other than shorts

ED Short circuit/arcing/low impedance: electrical component shorts or arcs in the circuit or has a low impedance including shorts to ground

EE Open circuit/high impedance/bad electrical contact: electrical component has a structural break, or electrical contacts fail to contact and fail to pass the desired current

EF Erratic operation: component (especially electrical or instrument) behaves erratically or inconsistently (if an instrument produces a bad but constant signal, use "EG;" if an instrument produces an inconsistent signal use "EF")

EG Erroneous/no signal: electrical component or instrument produces an erroneous signal or gives no signal at all (not for out-of-calibration error)

EH Drift: a change in a setting caused by aging or change of physical characteristics (does not include personnel errors or a physical shift of a component)

EI Out of calibration: component (particularly instruments) become out of adjustment or calibration (does not include drift)

EJ Electromagnetic interference: abnormal indication or action resulting from unanticipated electromagnetic field

EK Instrument snubbing: dampening of pulsating signals to an instrument

Hydraulic

HA High flow: higher than normal or desired flow exists in a component/system (does not include instrument misindication (see code EG)

HB Low flow: lower than normal or desired flow exists in a component/system (does not include instrument misindication)

HC No flow or impulse: fluid flowing through a pipe, filter, orifice, or trench or the fluid in an impulse line (e.g., instrument sensing line) is blocked completely or decreased due to some foreign material, crud, closed (either partially or completely) valve or damper, or insufficient flow area

Table 1.6 (continued)

HD Flow induced vibration

HE Cavitation

HF Erosion

HG Vortex formation

HH Water hammer

HI Pressure pulse/surge

HJ Air/steam binding

HK Loss of pump section

HL Boron precipitation

<u>Other</u>

OA Declared inoperable: component or system is declared inoperable as required by Technical Specifications but may be capable of partially or completely performing its desired duties when requested (a component/system that is <u>completely</u> failed should not use this code)

OB Flux anomaly: flux characteristics of the reactor core are not as required or desired (e.g., flux spike due to xenon burnout)

OC Test not performed: operator or test personnel fails to perform a required test within the required period

OD Radioactivity contamination: component, system, or area becomes more radioactive than desired or expected

OE Temporary modification: an installation intended for short term use (usually this is for maintenance or modification of installed equipment)

OF Environmental anomaly

OG Airborne release

OH Waterborne release

OI Operator communication

OJ Operator incorrect action

OK Procedure or record error

2. SOURCES OF INFORMATION

Several sources of information including periodic (annual, quarterly, and monthly) NRC publications were used in the review. Some sources contained information relative to more than one area within the scope of the review.

2.1 Availability and Capacity Factors

The availability and capacity factors were either extracted or calculated from data given in the Gray Books[3] from 1974 through 1981 (the first Gray Book was issued in May 1974). Prior to 1974, annual or semiannual reports were used to compile availability factors only.

2.2 Forced Reactor Shutdowns and Power Reductions

Review of the forced power reductions involved checking the following sources for accuracy and completeness of details.

1. Nuclear Power Plant Operating Experience for 19XX, for the years 1973-1979 (Refs. 4-11). The report for 1981 has not been published. However, because work on the section on outages in these reports has been performed by NSIC since 1973, the draft copy of this report for 1981 was available.
2. NUREG-0020 series[3] (Gray Books).
3. Annual or semiannual reports of the Millstone 1 plant from the time of startup through 1977. For 1977 through 1981, monthly operating reports were used because the utilities were no longer required to file annual reports. The review of power reductions involved primarily the annual, semiannual, and monthly reports.

2.3 Reportable Events

The NSIC computer file of LERs was the primary source of information in reviewing reportable events. Material on the NSIC computer file consists of the appropriate bibliographic material, title, 100-word abstract, and keywords. When additional information on the event was needed, the original LER (or equivalent) was consulted by examining (1) those full-sized copies on file at NSIC (for the years 1976-1981); (2) the microfiche file of docket material at NSIC; or (3) the appropriate operating report (semiannual, annual, or monthly).

Two computer files on RECON (a computer retrieval system containing ~40 data bases operated at ORNL) were used extensively. Printouts were obtained from the files for Millstone 1 to provide coverage on many types of "docket material," including reportable events, where the licensee may have been in correspondence with NRC [or the Atomic Energy Commission (AEC)] concerning a particular event. Licensees are often requested to submit additional information or perform further analysis. Before the

LERs came into existence in the mid-1970s, it was not unusual for licensees to submit, on their own or at the request of NRC or AEC, more than one letter transmitting information on a particular event. Thus, these printouts provided additional sources of information on reportable events.

Several special publications were reviewed to provide details on events of significance. After further analyses and examination of the following publications, details, evaluations, or assessments could be found other than those provided in the appropriate NRC-requested transmission.

1. "Reports to Congress on Abnormal Occurrences," NUREG-0090 series[12],
2. "Power Reactor Event Series" (formerly Current Event Series) published bimonthly by NRC,
3. "Operating Experiences," a section of each issue of the *Nuclear Safety* journal, and
4. the publications of NRC's Office of Inspection and Enforcement (IE), such as operating experience bulletins, IE bulletions, IE circulars, and IE information notices.

2.4 Environmental Events and Releases of Radioactivity

Events of environmental importance were obtained as a result of conducting the overall review of the plant's operating history, and the sources of information involve all types of documents listed thus far.

The data for radioactivity releases were compiled primarily from *Radioactive Materials Released from Nuclear Power Plants — Annual Report 1977* (Ref. 13). This report presents year-by-year comparisons for plants in a number of different categories (such as solid, gas, liquid, noble gas, and tritium). Data for 1978 were taken from *Radioactive Materials Released from Nuclear Power Plants — Annual Report 1978* (Ref. 14). Data for 1979, 1980, and 1981 were compiled from the annual environmental reports submitted by Millstone 1.

3. TECHNICAL APPROACH FOR EVALUATIONS OF OPERATING HISTORY

Forced shutdowns (and power reductions) and reportable events were the two areas focused on in the evaluation of the operating history of Millstone 1. Given the large number of both forced shutdowns and reportable events, it was necessary to develop consistent review procedures that involved screening and categorizing of both occurrences. After the events were screened and categorized, the study then assessed the safety significance of the events and analyzed the categories of events for various trends and recurring problems.

The approach in evaluation of operational events (forced shutdowns and reportable occurrences) consisted primarily of a three-step process: (1) compilation of information on the events, (2) screening of the events for significance using selected criteria and guidelines, and (3) evaluation of the significance and importance of the events from a safety standpoint. The evaluations were to determine those areas where safety problems existed in terms of systems, equipment, procedures, and human error.

Shutdowns were evaluated against the DBEs found in Chap. 15 of the *Standard Review Plan.*[3] The DBEs are those postulated disturbances in process variables or postulated malfunctions or failures of equipment that the plants are designed to withstand and that licensees analyze and include in safety analysis reports (SARs). The SAR provides the opportunity for the effects of anticipated process disturbances and postulated component failures to be examined to determine their consequences and to evaluate the capability built into the plant to control or accommodate such failures and situations (or to identify the limitations of expected performance).

The intent is to organize the transients and accidents considered by the licensee and presented in the SAR in a manner that will:

1. ensure that a sufficiently broad spectrum of initiating events has been considered,
2. categorize the initiating events by type and expected frequency of occurrence so that only the limiting cases in each group need to be quantitatively analyzed, and
3. permit the consistent application of specific acceptance criteria for each postulated initiating event.

Each postulated initiating event is to be assigned to one of the following categories:

1. increase in heat removal by the turbine plant,
2. decrease in heat removal by the turbine plant,
3. decrease in reactor coolant system flow rate,
4. anomalies in reactivity and power distribution,
5. increase in reactor coolant inventory,
6. decrease in reactor coolant inventory,
7. radioactive release from a subsystem or component, or
8. anticipated transients without scram.

Those shutdowns identified as design-basis initiating events were categorized as such. If the shutdown was not a DBE, then it was assigned a category from a list developed by NSIC to indicate the nature and type of error or failure. The NSIC categories for shutdowns not caused by DBEs were examined as part of a trends analysis.

Reportable events were screened using the criteria presented in Sect. 3.2 and were categorized according to their significance. The information collected on the reportable events was used to analyze trends for all reportable events, both significant and not significant.

3.1 Significant Shutdowns and Power Reductions

For the purposes of compiling information and evaluation, power reductions were treated in the same manner as forced shutdowns.

3.1.1 Criteria for significant shutdowns and power reductions

As indicated previously, the occurrences identified as DBEs were used as criteria to categorize and note significant shutdowns. These events are listed in Table 3.1 at the end of Sect. 3 as they are found in Chap. 15 of the *Standard Review Plan*.[2]

3.1.2 Use of criteria for determining significant shutdowns and power reductions

Generic design-basis initiating events such as "increase in heat removal by the secondary system" or "decrease in reactor coolant system flow rate," were used as primary flags for reviewing the forced shutdowns (and power reductions). Once the generic type of event was identified, the particular initiating event was determined from the details associated with the shutdown. For example, if the reactor shuts down because of an increase in heat removal because a feedwater regulator valve failed open, the shutdown is a generic type 1 DBE. Specifically, based on the initiating event (valve failed open), it is a 1.2 DBE — "feedwater system malfunction that results in an increase in feedwater flow." Some shutdowns were readily identifiable as specific DBEs, such as tripping of a main coolant pump, a 3.1 DBE. Once categorized as a DBE, the shutdown was considered significant regardless of the resulting effect on the plant (because a DBE had been initiated).

Loss of flow from one feedwater loop was considered sufficient to qualify as a 2.7 DBE — "loss of normal feedwater flow." The closure of a main steam isolation valve in one loop was considered sufficient to qualify as a 2.4 DBE — "inadvertent closure of main steam isolation valves."

3.1.3 Non-DBE shutdown and power reduction categorization

Those shutdowns that were not DBEs were assigned NSIC categories (Table 3.2) to provide more information on the failure or error associated with the shutdown. With these categories, more specific types of errors and failures could be examined through tabular summaries to focus the reviewer's attention on problem areas (safety related or not) that were not revealed by the DBE categories.

The causes (Table 1.1) for non-DBE shutdowns taken from the Gray Books are limited and very general, while NSIC cause categories are more specific. Thus, as an example, the number of Gray Book causes noted as equipment failure should not be expected to equal those identified as equipment failures with the NSIC categories. Other NSIC categories, such as component failure, could be classified as an equipment failure if the only available designations for cause were those listed in the Gray Books.

3.2 Significant Reportable Events

3.2.1 Criteria for significant reportable events

Two groups of criteria were used in determining significant reportable events. The first set of criteria (Table 3.3) indicates those events that are definitely significant in terms of safety; they are termed significant. The second set of criteria (Table 3.4) indicates events that may be of potential concern. These events, which might require additional information or evaluation to determine their full implication, were noted as conditionally significant.

3.2.2 Use of criteria for determining significant reportable events

The reportable events were all reviewed, applying the two sets of criteria for significance rather liberally. A number of significant events and conditionally significant events were noted. The events initially identified as significant or conditionally significant were analyzed and evaluated further based on (1) engineering judgment; (2) the systems, equipment, or components involved; or (3) whether the safety of the plant was compromised. The final evaluation for significance considered whether a DBE was initiated or whether a safety function was compromised so that the system as designed could not mitigate the progression of events. Thus, the number of events finally categorized as significant was reduced considerably by these steps in the review process.

3.2.3 Reportable events that were not significant

Those reportable events not identified as significant or conditionally significant were categorized as not significant (with an "N" in the significance column of the coding sheets in the appendixes). These events and the events rejected during the additional review step were further reviewed by compiling a tabular summary of the systems to detect trends and recurring problems (Table 1.4 provides a listing of the systems).

Table 3.1. Initiating event descriptions for DBEs as listed in Chap. 15, *Standard Review Plan* (Revision 3)

1. Increase in heat removal by the secondary system
   - 1.1 Feedwater system malfunction that results in a decrease in feedwater temperature
   - 1.2 Feedwater system malfunction that results in an increase in feedwater flow
   - 1.3 Steam pressure regulator malfunction or failure that results in increasing steam flow
   - 1.4 Inadvertent opening of a steam generator relief or safety valve
   - 1.5 Spectrum of steam system piping failures inside and outside of containment in a pressurized-water reactor (PWR)
   - 1.6 Startup of idle recirculation pump[a]
   - 1.7 Inadvertent opening of bypass resulting in increase in steam flow[a]
2. Decrease in heat removal by the secondary system
   - 2.1 Steam pressure regulator malfunction or failure that results in decreasing steam flow
   - 2.2 Loss of external electric load
   - 2.3 Turbine trip (stop valve closure)
   - 2.4 Inadvertent closure of main steam isolation valves
   - 2.5 Loss of condenser vacuum
   - 2.6 Coincident loss of onsite and external (offsite) ac power to the station
   - 2.7 Loss of normal feedwater flow
   - 2.8 Feedwater piping break
   - 2.9 Feedwater system malfunctions that result in an increase in feedwater temperature[a]
3. Decrease in reactor coolant system flow rate
   - 3.1 Single and multiple reactor coolant pump trips
   - 3.2 Boiling-water reactor (BWR) recirculation loop controller malfunction that results in decreasing flow rate
   - 3.3 Reactor coolant pump shaft seizure
   - 3.4 Reactor coolant pump shaft break
4. Reactivity and power distribution anomalies
   - 4.1 Uncontrolled control rod assembly withdrawal from a subcritical or low-power start-up condition (assuming the most unfavorable reactivity conditions of the core and reactor coolant system), including control rod or temporary control device removal error during refueling
   - 4.2 Uncontrolled control rod assembly withdrawal at the particular power level (assuming the most unfavorable reactivity conditions of the core and reactor coolant system) that yields the most severe results (low power to full power)
   - 4.3 Control rod maloperation (system malfunction or operator error), including maloperation of part length control rods

Table 3.1 (continued)

4.4 Start-up of an inactive reactor coolant loop or recirculating loop at an incorrect temperature.
4.5 A malfunction or failure of the flow controller in a BWR loop that results in an increased reactor coolant flow rate
4.6 Chemical and volume control system malfunction that results in a decrease in the boron concentration in the reactor coolant of a PWR
4.7 Inadvertent loading and operation of a fuel assembly in an improper position
4.8 Spectrum of rod ejection accidents in a PWR
4.9 Spectrum of rod drop accidents in a BWR

5. Increase in reactor coolant inventory

5.1 Inadvertent operation of emergency core cooling system during power operation.
5.2 Chemical and volume control system malfunction (or operator error) that increases reactor coolant inventory
5.3 A number of BWR transients, including items 1.2 and 2.1–2.6

6. Decrease in reactor coolant inventory

6.1 Inadvertent opening of a pressurizer safety or relief valve in either a PWR or a BWR
6.2 Break in instrument line or other lines from reactor coolant pressure boundary that penetrate containment
6.3 Steam generator tube failure
6.4 Spectrum of BWR steam system piping failures outside of containment
6.5 Loss-of-coolant accidents resulting from the spectrum of postulated piping breaks within the reactor coolant pressure boundary, including steam line breaks inside of containment in a BWR
6.6 A number of BWR transients, including items 1.3, 2.7, and 2.8

7. Radioactive release from a subsystem or component

7.1 Radioactive gas waste system leak or failure
7.2 Radioactive liquid waste system leak or failure
7.3 Postulated radioactive releases due to liquid tank failures
7.4 Design basis fuel handling accidents in the containment and spent fuel storage buildings
7.5 Spent fuel cask drop accidents

8. Anticipated transients without scram

8.1 Inadvertent control rod withdrawal
8.2 Loss of feedwater
8.3 Loss of ac power
8.4 Loss of electrical load
8.5 Loss of condenser vacuum
8.6 Turbine trip
8.7 Closure of main steam line isolation valves

[a] These initiating events were added for BWRs to be more specific than DBE events 5.3 and 6.6.

Table 3.2. NSIC event categories for non-DBE shutdowns

- N 1.0 Equipment failure
  - N 1.1 Failure on demand under operating conditions
    - N 1.1.1 Design error
    - N 1.1.2 Fabrication error
    - N 1.1.3 Installation error
    - N 1.1.4 End of design life/inherent failure/random failure
  - N 1.2 Failure on demand under test conditions
    - N 1.2.1 Design error
    - N 1.2.2 Fabrication error
    - N 1.2.3 Installation error
    - N 1.2.4 End of design life/inherent failure/random failure
- N 2.0 Instrumentation and control anomalies
  - N 2.1 Hardware failure
  - N 2.2 Power supply problem
  - N 2.3 Setpoint drift
  - N 2.4 Spurious signal
  - N 2.5 Design inadequacy (system required to function outside design specifications
- N 3.0 Non-DBE reductions in coolant inventory (leaks)
  - N 3.1 In primary system
  - N 3.2 In secondary system and auxiliaries
- N 4.0 Fuel/cladding failure (densification, swelling, failed fuel elements as indicated by elevated coolant activity)
- N 5.0 Maintenance error
  - N 5.1 Failure to repair component/equipment/system
  - N 5.2 Calibration error
- N 6.0 Operator error
  - N 6.1 Incorrect action (based on correct understanding on the part of the operator and proper procedures, the operator turned the wrong switch or valve — incorrect action)
  - N 6.2 Action on misunderstanding (based on proper procedures and improper understanding or misinterpretation on the operator's part of what was to be done — incorrect action)
  - N 6.3 Inadvertent action (purpose and action not related, for example, bumping against a switch or instrument cabinet)
- N 7.0 Procedural/administrative error (incorrect operating or testing procedures, incorrect analysis of an event — failure to consider certain conditions in analysis)
- N 8.0 Regulatory restriction
  - N 8.1 Notice of generic event
  - N 8.2 Notice of violation
  - N 8.3 Backfit/reanalysis

Table 3.2 (continued)

N 9.0	External events
	N 9.1 Human induced (sabotage, plane crashes into transformer)
	N 9.2 Environment induced (tornado, severe weather, floods, earthquake)
N 10.0	Environmental operating constraint as set forth in Technical Specifications

Table 3.3. Reportable event criteria — significant

Category of significance	Event description
S1	Two or more failures occur in redundant systems during the same event
S2	Two or more failures due to a common cause occur during the same event
S3	Three or more failures occur during the same event
S4	Component failures occur that would have easily escaped detection by testing or examination
S5	An event proceeds in a way significantly different from what would be expected
S6	An event or operating condition occurs that is not enveloped by the plant design bases
S7	An event occurs that could have been a greater threat to plant safety with (1) different plant conditions, (2) the advent of another credible occurrence, or (3) a different progression of occurrences
S8	Administrative, procedural, or operational errors are committed that resulted from a fundamental misunderstanding of plant performance or safety requirements
S9	Other (explain)

Table 3.4. Reportable event criteria — conditionally significant

Category of conditional significance	Event description
C1	A single failure occurs in a nonredundant system
C2	Two apparently unrelated failures occur during the same event
C3	A problem results in an offsite radiation release or exposure to personnel
C4	A design or manufacturing deficiency is identified as the cause of a failure or potential failure
C5	A problem results in a long outage or major equipment damage
C6	An engineering safety feature actuation occurs during an event
C7	A particular occurrence is recognized as having a significant recurrence rate
C8	Other (explain)

4. OPERATING EXPERIENCE REVIEW OF MILLSTONE 1

4.1 Summary of Operational Events of Safety Importance

The operational history of Millstone 1 has been reviewed to indicate those areas of plant operation that compromised plant safety. The review included a detailed examination of plant shutdowns, power reductions, reportable events, and events of special environmental importance. The criteria used to show degradations in plant safety were (1) events that initiated a DBE and (2) events that compromised safety functions designed to mitigate the propagation of the initiating events.

Shutdowns and power reductions indicated the number and types of DBE's entered. The reportable events and special environmental events indicated the number of times each engineered safety function was compromised. The results of the analyses identified 54 DBEs entered. Additionally, 11 events were identified in which a loss of safety system function occurred in some engineered safety features.

4.2 General Plant Description

The Millstone Nuclear Power Station Unit 1 is a General Electric boiling water reactor (BWR) of 652 MWe net maximum dependable capacity, owned by Northeast Nuclear Energy Company and located in Waterford, Connecticut. The Architect/Engineer was Ebasco Services Incorporated, and the constructor was the General Electric Company. The condenser cooling method is once-through, and Long Island Sound is the condenser cooling water source. The Plant is subject to license DPR-21, issued October 7, 1970, pursuant to Docket No. 50-245. The date of initial reactor criticality was October 26, 1970, and commercial generation of power began in December 1970.

The nearest city is New London, Connecticut, 3.2 miles away. The population within 6 miles is about 67,000, increasing in the summer to 83,000. The population within 20 miles is estimated at 330,000.

4.3 Availability and Capacity Factors

Table 4.1 contains the Millstone 1 availability and capacity factors. The reactor availability from 1971 through 1981 stayed above 70% except for two years, 1973 and 1981, when major outages were necessary for repair. In 1973, the feedwater spargers had to be replaced which necessitated an outage lasting almost 90 days. In 1981, after a seven month refueling outage, turbine balancing problems forced a 57 day repair outage. The 11 full years of operation, 1971 to 1981, averaged 76.1% reactor availability and 70.6% plant availability. Capacity factors were not available prior to 1973. The MDC and DER capacity factors from 1973 through 1981 averaged 62.2 and 61.6%, respectively.

Table 4.1. Availability and capacity factors for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Cumulative
Reactor availability	ND[a]	74.1	89.2	47.3	80.9	79.0	84.0	96.0	89.0	79.1	76.0	69.0	76.1
Unit availability	ND	69.3	88.1	45.5	79.1	75.6	76.1	89.6	87.6	77.3	69.0	51.6	70.6
Unit capacity (MDC)[b]	ND	ND	ND	33.8	63.1	68.4	66.1	84.1	81.3	73.7	59.0	44.0	62.2
Unit capacity (DER)[c]	ND	ND	ND	33.2	59.6	68.4	65.6	83.4	80.5	73.0	58.5	43.6	61.6

[a]ND = No data.

[b]MDC = maximum dependable capacity.

[c]DER = design electrical rating.

4.4 Forced Reactor Shutdown and Power Reductions

4.4.1 Review of reactor shutdowns and power reductions

Table A1.1 through A1.12 in the Appendix provides a comprehensive summary of information concerning forced shutdowns and power reductions at Millstone 1. More complete information was provided when events generated reportable events; in such instances, more detailed descriptions are in Sect. 4.5.

Tables 4.2 and 4.3 of forced shutdowns and power reductions summarize Table A.1. Causes of forced shutdowns, item I.3 in Table 4.2 and item I.2 in Table 4.3, are dominated at Millstone 1 by equipment failures. Shutdowns reported to be caused by operator errors amount to only six of the total, and no power reductions were attributed to operator error.

4.4.1.1 Yearly summaries for Millstone 1 . A discussion of shutdowns and power reductions for each year, 1970 through 1981 follows.

1970

The Millstone 1 BWR went critical on October 26, 1970. Seven shutdowns took place during startup testing. These were split about evenly between instrumentation malfunctions and faulty equipment installations. Maintenance and testing were the causes for all forced outages. The reactor coolant system was involved three times, and the steam and power system was involved three times.

One shutdown was due to a cracked seal weld on the main condenser. Oscillation of a pressure control torque tube tore a bypass valve linkage away from its support, necessitating a shutdown.

A problem, recurring in later periods, first surfaced during this report period. The problem involved a momentary moisture separator drain tank high level indication which subsequently tripped the turbine resulting in a reactor shutdown.

1971

During 1971, the reactor experienced 42 forced shutdowns, the most in a single year in the 10 years of operation at Millstone 1 (Table 4.2). The shutdowns were attributed primarily to equipment failures (37 times). Three of the forced shutdowns were caused by maintenance and testing; 2 were for operator error.

The longest forced shutdown occurred on October 10, when the unit was down for 10 d to repair a turbine control valve. The next longest forced shutdown occurred on August 30, and lasted for 7 d. The traveling screens of the circulating water system became clogged with sea-weed causing the loss of the main condenser vacuum and a reactor scram.

At the beginning of 1971, only two months after the initial criticality, a high level indication in the moisture separator drain tank caused a steam turbine trip. This event recurred 11 more times during the year. These high level indications were attributed to broken baffle plate welds and level control instrumentation malfunctions.

Table 4.2. Forced shutdown summary for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
I. Forced shutdowns													
1. **Total number**	8	42	8	20	7	11	8	14	6	7	1	9	141
2. **Total hours down**	102	1336	585	2892	91	976	624	738	197	424	13	1641	9619
3. **Cause**[a]													
A. **Equipment failure**		37 (1207)	8 (585)	16 (2594)	7 (91)	8 (502)	7 (519)	14 (738)	5 (97)	7 (424)	1 (13)	7 (1534)	117 (8304)
B. **Maintenance or testing**	8 (102)	3 (121)				1 (451)			1 (100)			1 (55)	14 (829)
D. **Regulatory restriction**				1 (236)									1 (236)
E. **Operator training/license exam**													
F. **Administrative**													
G. **Operational error**		2 (8)		3 (62)								1 (52)	6 (122)
H. **Other**													
4. **Shutdown method**													
A. **Manual**	3	11	4	12	2	7	5	2	2	2		1	51
B. **Manual scram**						1		4		1		2	8
C. **Automatic scram**	5	31	4	8	5	3	2	8	3	3	1	4	77
D. **Other**							1		1	1		2	5
II. Total number of DBE related shutdowns (these are **included in totals of Part I**)	4 (53)	24 (858)	4 (218)	3 (151)	6 (23)	0 (0)	0 (0)	2 (65)	3 (39)	3 (85)	1 (13)	4 (1436)	54 (2941)
1. **Reactor vessels** (CA)				6									6
2. Coolant recirculation system (CB)		2		4	1			1				1	9
3. **Main steam systems** and controls (CC)	1	8	3	3	2	5		1	2	1	1		27
4. **Main steam** isolation **systems** (CD)	1			1				1		1			4
5. **Reactor** core isolation cooling **system** (CE)	1	1		1			2						5
6. **Reactor** coolant cleanup **systems** (CG)								1		1			2
7. **Feedwater system** (CH)		1	1	3	2			1		1		2	11
8. **Offsite** power **systems** (EA)	1												1
9. **AC onsite** power **systems** (EB)						3	2						5
10. **Onsite** power **systems** (ED)									1				1
11. **Emergency** lighting **systems** (EF)						1							1
12. **Turbine** generator and controls (HA)	2	20	3		1		1	1	1	1		3	33
13. **Main steam** supply **system** (HB)								5	1				6
14. **Main** condenser **systems** (HC)	1	2										1	4
15. **Turbine** bypass **systems** (HE)	1												1
16. **Circulating** water **systems** (HF)		2											2
17. **Condensate** and feedwater **systems** (HH)		1											1
18. **Steam** generator blowdown **systems** (HI)		1											1
19. **Reactor** trip **systems** (IA)		1						1	1			3	6
20. **Gaseous** radwaste management **system** (MB)								1					1
21. **Compressed** air **systems** (PA)								1		1			2
22. **Reactivity** controls **systems** (RB)				2									2
23. **Reactor** core (RC)						1							1
24. **Reactor** containment **systems** (SA)		1	1		1								3
25. **Emergency** core cooling **system** (SF)										1			1
26. **Low** pressure safety injection **system** (SF-B)						1							1
27. **Core spray system** (SF-D)		2											2
28. **Station** service water **systems** (WA)						1							1

[a]**Number** of hours associated with cause of shutdown is in parentheses.

Table 4.3. Power reduction summary for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
I. Power reductions													
1. Total number					7	3	1	3	10	3	1	3	31
2. Cause													
A. Equipment failure					7	2		1	10		1	2	23
B. Maintenance or testing						1		2		3		1	7
H. Other							1						1
3. System involved													
A. Turbine-generator (HA)					3			1					4
B. Main condenser (HC)					2			2	10	3		1	18
C. Reactor (RB)							1						1
D. Reactor (RC)						1							1
E. Electric power (EB)					1	1							2
F. Reactor coolant (CC)					1	1							2
G. Reactor coolant (CD)											1		1
H. Other instruments required for safety (IE)												1	1
I. Station service water (WA)												1	1
4. Total number of DBEs related power reductions (included in totals of Part 1)					3								3

Another recurring event during this year first occurred on March 23. The malfunction of the steam turbine control valve necessitated a 2-d shutdown for valve testing. Six additional forced shutdowns occurred due to malfunctioning of this valve.

There were six shutdowns due to miscellaneous instrumentation malfunctions. During two shutdowns, Millstone 1 repaired leaks in the main steam line.

1972

The number of forced outages dropped to 8 in 1972 (Table A.1.3), with no reported power reductions. The total forced down time was only 585 h, fourth lowest in Millstone 1's history.

Two forced shutdowns in February lasted for 12 d. These were due to improper responses from the main steam line venturi differential pressure transmitters. The sensing tubes were replaced. On March 12, a reactor scram occurred during plant heatup when a reactor feed pump was started at the 10-in. level indication in the reactor vessel. Collapse of voids from the cold feedwater resulted in a level decrease and the resultant low level scram.

During the refueling outage which commenced September 1, the leaking tubes in the main condenser were plugged and all incore power range detectors were replaced.

1973

This year saw the second most forced shutdowns in Millstone 1's history: 20 forced shutdowns for 2892 h total (Table A.1.4). Sixteen of these shutdowns were attributed to equipment failures. The longest forced shutdown occurred on April 18, and lasted for 89 d. At this time, all of the feed-water spargers were replaced because of cracks.

There was one forced shutdown of 10 d at the direction of the Atomic Energy Commission (AEC) to examine for possible inverted control rod internals. The General Electric Company had provided notice that some of the boron carbide poison pins were inverted during the blade fabrication process of some control rods, and some of these rods might have been installed in the Millstone core. In this inverted configuration, it was conceivable that axial downward shifting of the boron carbide powder could occur, and that this shifting could result in a change in the reactor core shutdown margin. A series of shutdown tests subsequently indicated nothing remiss.

Four of the shutdowns were due to instrumentation malfunctions, and four were due to lube oil pressure alarms on the reactor recirculating pump motor.

1974

This year saw the second least forced downtime in Millstone 1's history: seven forced shutdowns for 91 h total (Table A.1.4). A total of seven power reductions were made which were attributed to equipment failure. Sea water leakage in the main condenser was detected necessitating two power reductions to plug tubes.

A recurring problem of turbine trips accounted for three more power reductions. These were again attributed to high level indication in the moisture separator drain tank.

A refueling outage commenced on September 1, during which time the feedwater spargers were replaced due to excessive vibration at reactor power levels greater than 80%.

1975

This year Millstone 1 suffered the third most forced downtime in its history. Of a total of 976 h forced out of service, 56% were caused by a transformer failure that caused a 44-d shutdown. On September 12, a combustible gas mixture was detected in the transformer, and a shutdown was made to change-out the transformer. Refueling was completed during this outage.

On March 3, a blown valve stuffing box on the low pressure cooling injection system occurred, resulting in water blowing from the identified leakage sump into the unidentified leakage sump.

1976

This year there were eight forced shutdowns. On August 10, high winds deposited salt spray on the main transformer insulators causing arcing and tripping the generator. During this outage the gas turbine speed control became inoperable necessitating the replacement of the electronic governor.

On July 16, a shutdown was necessary to repair the motor operator of the isolation condenser isolation valve. On December 17, this same valve malfunctioned resulting in a shutdown to clean it.

1977

In 1977, there were 14 forced shutdowns due to equipment failure for a total of 738 h. On June 14, a mechanical pressure regulator malfunctioned, tripping the steam turbine and causing a 5-day shutdown. In August, main condenser tube failures occurred again at Millstone 1. Several power reductions were made to plug leaking tubes. On December 13, 1977, the first of two hydrogen explosions occurred in the off-gas system and was confined to a massive underground pipe. Damage was minor and the reactor was allowed to continue operating while the damage was being repaired. The second explosion was not confined with considerable damage in a two-level room at the base of the stack and to the plant stack itself. The reactor was manually tripped.

1978

This year there were only six forced shutdowns for a total of 197 h. Starting in June, main condenser leakage troubled Millstone 1 for the rest of the year. Ten power reductions took place in order to plug leaking tubes. Again, level control malfunctions occurred in the moisture separator drain tank.

1979

Seven forced shutdowns occurred this year for a total of 424 h. The most significant one occurred on January 6 and lasted for 11 d. Stress corrosion cracking in the clean-up return line necessitated replacement of this piping. Again, the plugging of leaking main condenser tubes caused three power reductions. On July 2, a shutdown, due to low water level from the feedwater regulator valve lockup, resulted from the loss of both plant air compressors.

1980

Only one forced shutdown was reported in 1980. A water hammer was experienced in the isolation condenser piping on December 19, 1979. The isolation condenser was placed out of service on January 5. Power was reduced and restricted to 40% for 27 d during the modifications made to the isolation condenser piping supports.

1981

At the beginning of 1981, Millstone 1 was continuing a refueling/ maintenance outage which had begun October 4, 1980. The outage continued 2598 h from January 1 until the middle of April. There were nine forced shutdowns totaling 1641 h of downtime and three forced power reductions.

On April 21, the turbine was experiencing high vibration and was manually tripped. The reactor scrammed due to high main condenser conductivity. Balancing problems caused a continued turbine outage which lasted 1372 h.

On July 12, a feedwater regulator valve failed to close. On August 8, recirculation pump "A" tripped while recirculation pump "B" was off-line. The unit was manually scrammed.

On August 10, a scram occurred during a surveillance test when an operator failed to reset a scrammed channel before testing the other channel. On September 14, a power surge to the ATWS system caused the scram air header to depressurize.

4.4.1.2 Systems involved. Twenty-eight different systems were involved with turbine generator and controls system and main steam system controls system accounting for 45% of the events. For the operating history of the plant through 1980, excluding these two systems, the average number of forced shutdowns per system was three.

There were 30 forced shutdowns involving turbine-generator and controls with 20 of these occurring during 1971. In 1971, 14 events dealt with high moisture separator drain tank level, 4 with turbine control valves, and 2 were caused by the loss of an offsite power line due to lightning. In 1979, a loss of main generator excitation was experienced.

There were 27 forced shutdowns involving main steam systems and controls. Almost one-third of these occurred in 1971. On 11/11/70, 11/21/70, 11/4/74, and 7/12/77 inadvertent closure of MSIVs occurred. On 3/2/71, 10/21/71, 9/20/73, 5/20/77, 11/29/77, and 2/26/79, pressure relief or safety valves either failed to close or opened prematurely.

There were seven forced shutdowns dealing with condensate and feedwater systems. On 5/25/71 and 12/16/74, feedwater control valve closures prevented the flow of feedwater. On 3/12/72, a void collapse occurred from an increase in cold feedwater flow. On 3/6/73, a condensate booster pump was not started in time, resulting in low water level. On 4/18/73, the feedwater sparger was replaced requiring a shutdown lasting 90 days. On 8/10/73, high reactor water level was experienced due to the starting of a feedwater pump.

Of the 28 power reductions, 61% involved the main condenser system. Three of the power reductions were considered DBE events.

4.4.1.3 Causes of forced reactor shutdowns and forced power reductions. Of the 141 forced shutdowns, 83% were caused by equipment failures for a total of 8304 h. Maintenance and testing accounted for 10% of the shutdowns, for a total of 774 h. There were only six due to operational error for a total of 122 h.

Of the 31 power reductions, 75% were caused by equipment failures. Maintenance and testing accounted for 25%.

4.4.1.4 Non-DBE shutdowns. Table 4.4 summarizes the NSIC categories assigned to non-DBE shutdowns. Only the major NSIC categories are listed in Table 4.5. Equipment failures accounted for 67% of the events with no apparent decline during the first nine years of operation. Instrumentation and control problems accounted for 20% of the events, and these occurred throughout the life of the operations.

4.4.2 DBE initiating events

Of the 172 forced shutdowns and power reductions accumulated at Millstone 1, 54 fell into DBE initiating event categories as shown in Tables 4.2 and 4.3. None of these events initiated a sequence that led to any significant economic loss or safety hazard to the plant or the environs. The trend of total number of DBEs per year bears no correlation with other trends, such as plant performance as measured by total number number of shutdowns per year or total downtime per time (Table 4.5).

4.4.2.1 DBE Sect. 1 events — increased in heat removal. Six events (12%) are categorized into this section. Four of the six were due to instrumentation malfunctions. One was attributed to operator error.

4.4.2.1.1 D1.1 — feedwater system malfunctions resulting in a decrease in feedwater flow. On May 25, 1971, a low water level reactor scram occurred when the valve positioner on one of the feedwater regulation valves failed. This caused the partial closure of a feedwater control valve resulting in insufficient flow and a reactor scram on low level.

4.4.2.1.2 D1.2 — feedwater system malfunctions that result in an increase in feedwater flow. On March 12, 1972, reactor scram occurred during plant heatup when a reactor feed pump was started at the 10-in. level indication in the reactor vessel. Void collapse from cold feedwater resulted in level decrease and low level scram.

Table 4.4. NSIC primary category summary for non-DBE shutdowns for Millstone 1

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
1. Equipment failures	3	11	3	9	3	9	7	6	1	3	0	1	56
2. Instrumentation and controls anomalies		2		5		1		6	1	1		3	19
3. Non-DBE reductions in coolant inventory (leaks)		2	1										3
4. Fuel/cladding failure													
5. Maintenance error						1							1
6. Operator error		2		1								1	4
7. Procedural/administrative error													
8. Regulatory restriction				1									1
9. External events							1		1				2
10. Environmental operating constraints Tech specs					1				1				2
TOTAL	3	17	4	16	4	11	8	12	3	4	0	5	87

Table 4.5. DBE initiating events at Millstone 1

	DBE category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Feedwater system malfunctions that result in a decrease in feedwater temperature	D-1.1		1											1
Feedwater system mallfunctions that result in an increase in feedwater flow	D-1.2			1	1									2
Steam pressure regulator malfunction or failure that results in increasing steam flow	D-1.3	2			1									3
Steam pressure regulator malfunction or failrre that results in decreasing steam flow	D-2.1	1	1									1		3
Loss of external electric load	D-2.2		2											2
Turbine trip (stop valve closure)	D-2.3	1	18	3		4				3	2			33
Inadvertent closure of main steam isolation valves	D-2.4					1			1					2
Loss of condenser vacuum	D-2.5		1											1
Loss of normal feedwater flow	D-2.7				1	1								3
Single or multiple reactor recirculation pump trips	D-3.1												1	1
Inadvertent opening of a pressurizer safety or relief valve in a PWR or a safety or relief valve in a BWR	D-6.1		1						1		1			3
TOTAL		4	24	4	3	6	0	0	2	3	3	1	4	54

On August 10, 1973, a malfunction of a reactor water level transmitter resulted in a false low level signal to the feedwater control valve circuit. This resulted in increased flow followed by reactor high water level resulting in a scram. Later the same day, a scram due to high water level occurred when an operator started a feedwater pump with the feedwater regulating valves in full open position.

4.4.2.1.3 <u>D1.3 - steam pressure regulator malfunction or failure that results in an increasing steam flow.</u> There were three events of this kind, all attributed to instrumentation malfunctions. On November 19, 1970, installation of scrubbers near (on) main steam line high flow ΔP switches was in progress. While cutting in an isolated switch, a momentary high flow signal was initiated, the main steam lines isolated, generating the reactor scram.

On December 5, 1970, while shifting to EPR pressure control, EPR oscillated giving bypass valve swings and pressure and reactor vessel swings. Result was low level signal yielding a reactor scram. On September 21, 1973, a fault in the EPR controls opened the turbine bypass valves, dropping the reactor pressure.

4.4.2.2 <u>DBE Sect. 2 events -- decrease in heat removal.</u> Forty-four events are categorized into this section. Thirty-three of these 44 (74%) were caused by turbine trips. Three of these were associated with steam pressure regulator malfunction, two with loss of external electric load, two with inadvertent closures of main steam isolation valves, three with feedwater system, and one with loss of condenser vacuum.

4.4.2.2.1 <u>D2.1 - steam pressure regulator malfunction or failure that results in decreasing steam flow.</u> On November 21, 1970, vibration of the reactor mode switch resulted in main steam isolation. On January 19, 1971, the turbine control valve closed, causing the reactor shutdown. On June 25, 1980, an electric pressure regulator malfunction induced an APRM scram.

4.4.2.2.2 <u>D2.2 - loss of external load.</u> On June 24, 1971 and again on June 25, 1971, there were turbine full load rejects due to lightning causing loss of 345 kv line.

4.4.2.2.3 <u>D2.3 - turbine trip (stop valve closure).</u> Twenty-one of the 33 events were attributable to malfunctions of the moisture separator drain tank level control. This type of event first occurred on December 30, 1970, and continued for the next eight years - 14 occurring in 1971, 3 in 1974, and 3 in 1978, and 1 in 1981.

Five turbine control valve malfunctions (5-27-71, 9-29-71, 10-3-71, 10-10-71, 2-4-72) caused turbine trips.

4.4.2.2.4 <u>D2.4 - Inadvertent closure of main steam isolation valves.</u> The two events (11-4-74, 4-7-77) in this category were attributed to mechanical failures in valve actuators.

4.4.2.2.5 D2.5 - Loss of condenser vacuum. While this classification of D2.5 deals with the complete loss of condenser vacuum, it was felt that the only event (8-30-71) which dealt with low condenser vacuum should be included in this category.

4.4.2.2.6 D2.7 - Loss of normal feedwater flow. Of the two events in this category, one (3-6-73) was attributed to operator error in failing to start a condensate booster pump in time. The other event (12-16-74) was due to a broken stem on the feedwater control valve.

4.4.2.3 DBE Sect. 3 events - decrease in reactor recirculation flow rate. The sole shutdown which resulted from a decrease in reactor recirculation flow occurred in 1981. On August 8, 1981, the "A" reactor recirculation pump tripped on generator overload. The "B" reactor recirculation pump was off-line at the time and the unit was manually scrammed.

4.4.2.4 DBE Sect. 6 - decrease in reactor coolant inventory. All three of the following shutdowns were 6.1 DBEs. On March 2, 1971, a main steam safety valve started leaking, blowing steam. On November 29, 1977, the automatic pressure relief valve lifted prematurely. On February 26, 1979, the safety relief valve lifted prematurely and failed to reseat.

4.4.3 Trends and safety implications of shutdowns and power reductions

The only recurring problem associated with forced outages and power reductions was inadvertent or premature opening of pressure relief or safety valves or their failure to close or seat. On 10/22/71, a pressure relief valve failed to close completely. On 9/20/73, a pressure relief valve was leaking. On 5/20/75, a PRV failed to close completely. On 11/29/77, a PRV opened prematurely. On 2/26/79, a safety relief valve lifted prematurely and failed to seat. On 3/21/71 a main steam line relief valve was found blowing steam.

4.5 Reportable Events

This study reviewed 320 reportable events from Millstone 1. The events include telegrams, letters, abnormal occurrences (AOs), reportable occurrences (ROs) and licensee event reports (LERs) that were filed by the utility when a technical specification was violated. The information contained in the reportable events has been coded as discussed in Sect. 1.3. These tables, arranged by year, are presented in Appendix A, part 2.

4.5.1 Review of reportable events from 1970 through 1981

Figure 4.1 illustrates the number of reportable events filed per year at Millstone 1. There was a generally upward yearly trend on the numbers of reports. The following sections present a summary for each year of operating experience at Millstone 1, omitting environmental reports which are discussed in 4.5.1.4.

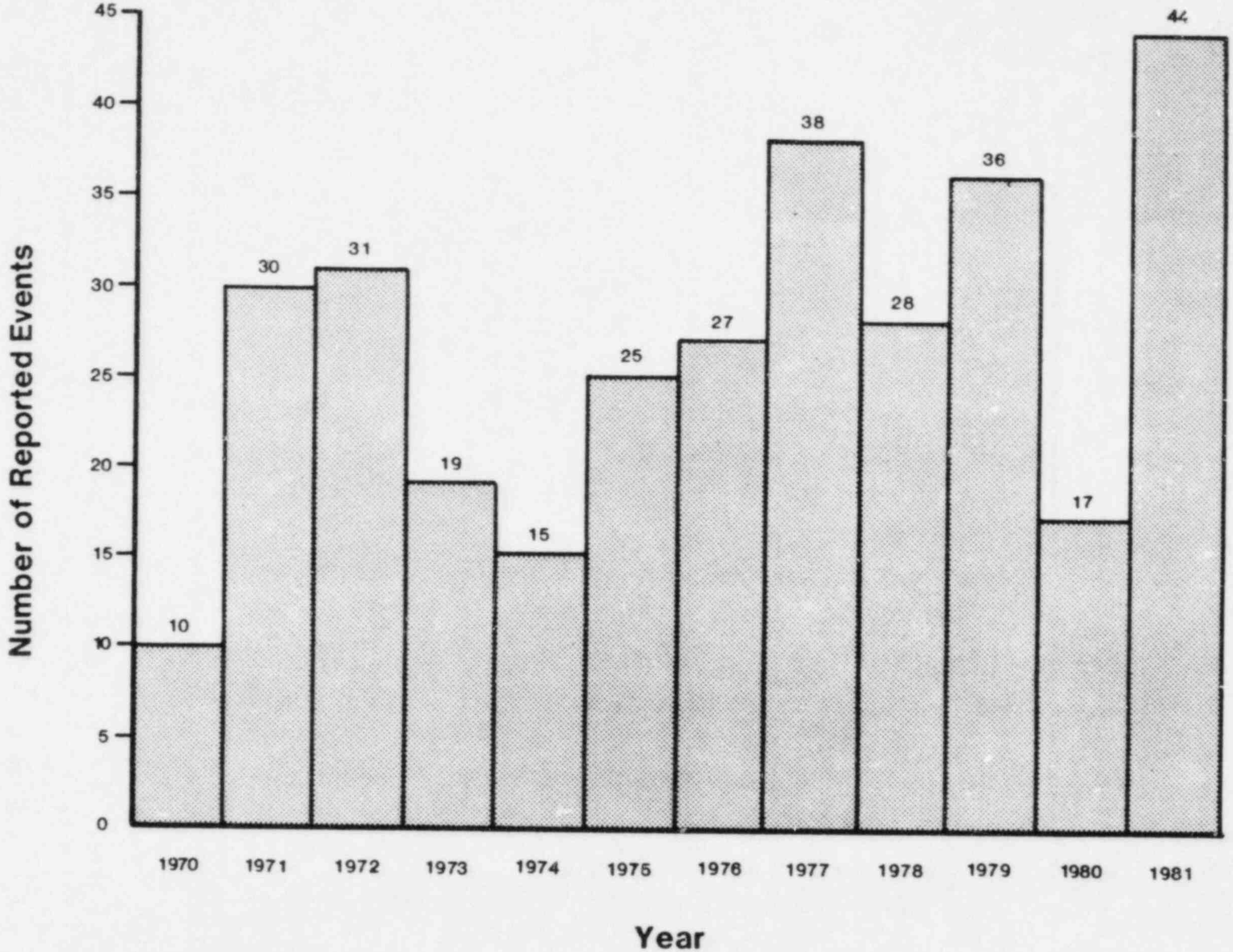

Figure 4.1 Number of Reported Events Per Year at Millstone 1

4.5.1.1 Yearly summaries of reportable events.

1970

The plant went critical on October 26, 1970. As expected, several design and installation errors surfaced during the first few months of operation.

In the two months of operation in 1970, ten reportable events occurred. Eight of these events resulted from human errors. Human errors consist of design errors (4), installation errors (3), operator and maintenance errors (1). Three of the design errors consisted of inadequate pipe support of the main steam lines (RS-70-6), inadequate lubrication oil pump speed (RS-70-4), and an inappropriate wiring change that resulted in a loss of full rod control (RO-70-7). The fourth error caused the isolation condenser to isolate (RO-70-5). A high-pressure signal initiated the operation of the isolation condenser. The resulting high condensate flow caused the isolation condenser to isolate. A restart of the system was unsuccessful and the pressure transient was brought under control through the use of relief valves.[15] This event is discussed in further detail in Sect. 4.5.3.3.

Installation errors included faulty welds in the main condenser (AO-70-8), failure of an MSIV due to missing parts (RS-70-6), and a vent line on the lube oil pump discharge line not being reinstalled (AO-70-10).

1971

Millstone 1 began commercial generation of power in March 1971, and experienced 30 reportable events during the year. Human errors again dominated the cause of the events (20). The human errors consisted of design errors (7), installation errors (5), maintenance errors (6), and operator errors (2). The most reported system failures occurred in the engineered safety features systems (12). The Emergency Core Cooling System (ECCS) and Low Pressure Coolant Injection System (LPCI) were involved in five events each. Only one event from these two systems was considered significant. On January 19, 1971, the entire low pressure ECCS was rendered inoperable during a test (AO-71-1). The core spray injection valve failed to close and two LPCI valves failed to open. A turbine control valve unexpectedly closed causing the other three control valves to open further. Severe pressure oscillations caused reactor power oscillations of 8%. As soon as pressure control was changed from the mechanical pressure regulator to the electrical pressure regulator, the oscillations stopped. This event is described in more detail in Sect. 4.5.1.2.3.

Two other significant events occurred during the year and both involved problems with the turbine electrical and mechanical pressure regulators (71-12 and 71-20). These problems were eliminated by replacing defective parts, and only one serious transient resulted from these malfunctions. Both incidents are discussed in detail in Sect. 4.5.2.

Two events worth noting also occurred in 1971. On May 1, a service water heat exchanger leak caused flooding of the DC motor control center (RO-71-09). On May 2, the cleanup system bypass valve motor burned out. This was followed by the failure of the DC motors to the shutdown cooling pump suction valve and the main steam outboard drain valve. All three valve failures resulted from moisture.

The other event was one of the five failures involving the gas turbine generator (71-25). The generator tripped on cold lube oil since the operator did not turn the lube oil heaters on. The gas turbine generator problems surfaced in later years as well and are discussed in Sect. 4.5.3.1.

1972

The number of reported events increased to 31 in 1972. Human errors again contributed to the number of events reported. Maintenance errors (7), design errors (3), and installation errors (2) all contributed. The systems involved in the most events were the main steam system (6) and the Reactor Core Isolation Cooling system (5). No significant events occurred during the year.

The 1972 operating experience was marred by salt water intrusion in the main condenser (AO-72-22). Loss of the main condenser is not critical for plant safety, but the presence of chlorine in the system manifested itself in damaging other components in the reactor coolant system, some of which were not discovered until 1976. Of the 120 local power range monitors (in-core), 116 failed due to stress corrosion brought about by the excessive chloride content in the reactor water. Problems also arose from cracking of feedwater spargers in 1972 (72-26). The capability of the system was not impaired since the system can operate with or without the spargers. All defective spargers were replaced.

On August 25, the plant experienced a loss of power to the shutdown transformers when a plane crashed into the 27.6 kv power line. The line was only 500 ft from the switchyard. The plant was operating at 82% power and did not reduce power after the crash.

1973

Nineteen reportable events occurred in 1975. Most reported events involved the feedwater control system (4) or the reactivity control system (4). Cracking of feedwater spargers was again noted in 1973. The capability of the system to perform its function was not decreased.

Several control rod system problems surfaced in 1973. The problems varied in nature, the most notable incident involved degradation of the control rod drive accumulators due to flaking of plating into the hydraulic system.[16] Six of the 143 accumulators had sufficient flaking to impair the operation of the control rod drive mechanism. These six were replaced and the hydraulic system was flushed. A program for monitoring accumulator conditions was initiated to prevent recurrence of the incident. Other problems involved valve and line leaks, none of which were serious and were easily repaired. This event is discussed in further detail in Sect. 4.5.2.

On April 5, pressure adjustments were being made as reactor power increased. The pressure momentarily reached 1042 psig initiating the isolation condenser. The position switches were incorrectly set causing the inboard condensate return valve to open too wide. The resulting high flow condition automatically isolated the condenser. Due to the frequency of the isolation condenser valve failures, this event is discussed further in Sect. 4.5.3.3.

1974

The second smallest number of reportable events occurred in 1974 (15). Most reported events involved the reactor coolant system (8). In particular the 1-MS-1D inboard isolation valve failed twice (AO-74-9,10) in one month. The cause of both failures involved foreign matter on the slide valve for the air operator. The slide valve was cleaned and the problem did not return.

Over one-half of the events involved a human error (9). Design errors and maintenance errors each accounted for four events. Two of the maintenance errors caused Main Steam Isolation Valve failures. The failures appear to be due to poor quality air to the pilot valves since the air slide valves stuck on both occasions. This failure mode is significant in that it can cause more than one MSIV to fail at the same time. This would lead to plant conditions not considered in the plant's safety analysis.

No significant events occurred during 1974.

1975

Twenty-five reportable events occurred in 1975. In January, a hydrogen explosion occurred in the condensate demineralizer regeneration system acid day tank (Ltr. 1/24/75). No one was injured. The hydrogen was formed by moisture leaking into a tank of concentrated sulfuric acid and was ignited by a spark caused by welders working in the vicinity.

More valve problems occurred in 1975, in particular, two events involved degradation of safety/relief valves. In one incident (AO-75-9) a safety/relief valve failed to reseat due to a malfunction of two pilot valves.[17] The reactor pressure dropped to 160 psig. During the blowdown, reactor cooldown rate reached 155 F/h, well above the limit of 100 F/h. No damage to reactor components occurred. Both pilot valves were replaced. In a second incident (AO-75-17) the bellows integrity of two safety relief valves could not be verified. Instrument air lines were fouled and had to be cleaned.

The human errors occurring during the year were due to maintenance errors (5), design errors (3), administrative errors (1), and installation errors (1). The most noteworthy human error was the administrative error. On March 30, radioactive liquids were discharged twice from an unmonitored sump. Previous samples from the sump showed no activity and none was anticipated. Procedures were modified to prevent a recurrence.

1976

Three of the 27 reportable events which occurred at Millstone 1 in 1976 were significant. Millstone 1 experienced several problems with the isolation condenser, beginning with a total failure of the condenser in February (see Sect. 4.5.2.1) and continuing throughout the year with various valve and control troubles.

Gas turbine generator problems also plagued the plant. One failure of the generator occurred during a total loss of offsite power (RO-76-29). See Sect. 4.5.2.2 for details. Gas turbine generator failures are discussed in detail in Sect. 4.5.3.1.

On November 17, 1976, an inadvertent criticality during a shutdown margin test occurred when an operator selected the wrong control rods for the test (RO-76-34). This event is discussed in Sect. 4.5.2.3.

It should also be noted that almost all (16/18) of the environmental violations at Millstone 1 occurred in 1976. These events were attributed to an unexpected increase in the abundance of marine life around the plant during the year. These events are discussed in further detail in Sect. 4.5.1.4.

1977

The second largest number of reportable events were recorded in 1977. Several events involved failures of valves in the main steam lines. Two of these failures affected safety/relief valves at Millstone 1. The first failure occurred on June 16 (AO-77-17) when a safety/relief valve opened at 555 psig and did not reseat until pressure dropped to 180 psig. No cause was reported. The second failure (AO-77-18) involved a safety relief valve which leaked due to a collapsed filter. The filter was replaced. Four failures involved the emergency electrical power systems. Three of these failures involved the diesel generator. On two occasions, the diesel generator failed due to a fuel oil leak. The third event resulted from the diesel generator being declared inoperable. The cause was unknown. There was only one gas turbine generator failure in 1977. A spurious noise signal caused the gas turbine generator's startup test to be stopped.

The only significant event to occur in 1977 involvd the off-gas system. The stack release rate increased after an explosion in the system. Four hours later, another explosion occurred. The second detonation occurred at the base of the stack. Two workers were injured but the safety of the plant was not challenged. This event is discussed in more detail in Sect. 4.5.2.5.

1978

Although there was a large number of reportable events in 1978 (28), none of them were significant. On March 10, 1978, a safety/relief valve failed to seat after manual operation, and then opened prematurely during an automatic test (AO-78-4).

On May 29, 1978, the isolation condenser was removed from the system due to failure of a steam trap (AO-78-13). Recurring problems with the isolation condenser are discussed in Sect. 4.5.3.3.

On September 5, 1978, one of four low-low water level sensors failed due to lack of lubrication (AO-78-18). The sensor is one of four used for ECCS initiation. The sensor was lubricated and then satisfactorily tested.

Of the 12 human errors, eight were due to maintenance. The most notable error was an administrative error. On July 25, the containment was purged with the high radiation signal to the containment purge valves bypassed. The high radiation override also bypasses the containment isolation actuation signal to the purge valves. On 12 occasions, the purge interval was greater than four hours. The operability requirements for these valves was not discussed in the procedures.

1979

In 1979, the third highest number of reportable events (36) over the operating experience of the plant were reported. On September 14, 1979, it was discovered that a design error allowed loss of power to the ECCS to go undetected under a certain electrical distribution arrangement (LER 79-26). The logic was changed to eliminate this possibility. This event is described in detail in Sect. 4.5.2.

Another significant event (also reported in Sect. 4.5.2) occurred on February 26. A pressure relief valve lifted prematurely and then failed to reseat (LER 79-05). An uncontrolled blowdown and excessive cooldown rate resulted. The cooldown rate limit of 100°/h was exceeded by 5°. The overall effect on reactor pressure vessel structural integrity was considered to be small.

Three other events worth noting occurred due to human errors. On February 1, an operator operated the plant in a degraded mode of operation (LER 79-06). One control rod had an inoperable accumulator and another control rod in the same array was electrically disarmed. The disarming of the second control rod was an oversight by the operator.

Defective procedures led to the sodium pentaborate concentration in the standby liquid control tanks being less than the limit on July 13, 1979 (LER 79-18). The concentration was increased immediately upon discovery and procedural changes were made to preclude a recurrence.

On December 19, 1979, a water hammer occurred in the isolation condenser piping (RO-79-36). The operators had been instructed to maximize the reactor vessel water level in order to minimize the thermal stress to the feedwater nozzles. The water hammer was caused by the introduction of the excess water into the steam supply lines of the isolation condenser. Operating procedures have been revised to avoid recurrence of this incident.

1980

Seventeen reportable events were recorded at Millstone 1 in 1980. Problems involving weld cracks in two main steam lines and in the condenser nozzle were reported. The cracks were discovered during the fall refueling outage. Pipe cracks at Millstone 1 are discussed in Sect. 4.5.3.2. No significant events occurred during 1980.

1981

In 1981, 45 events were reported which represented the largest number of reports submitted by Millstone. Instrumentation and controls system was the most reported system (14). Half of these events were due to set point drifts. The emergency generator system accounted for six events. All six events involved a diesel generator, a gas turbine generator, or both. The event that involved both generators was considered significant (LER 81-02). On April 3, personnel discovered that the potential existed for a single relay failure in the loss of normal power circuits would prevent the diesel generator and the gas turbine generator from energizing the emergency buses. The cause was a design oversight. For further details, see Sect. 4.5.2.

On April 19, two containment instrumentation isolation valves were closed (LER 81-03). The valves were required to be in the open position. The closure of these valves isolated a drywell high pressure switch associated with the ECCS and RPS initiation. Personnel also discovered that an isolation valve to pressure instrumentation that bypasses certain RPS scrams at low pressure was also closed. Further details of this event are given in Sect. 4.5.2.

The third significant event (also reported in Sect. 4.5.2) occurred on September 15 (LER 81-25). Voltage fluctuations in the 125 V DC electrical system resulted in an isolation of the ATWS system. This caused both recirculation pumps to trip. This condition was not annunciated in the control room and consequently, control room personnel were not alerted to the incident.

4.5.1.2 Systems involved in reportable events. A compilation of all reportable events by system and year is presented in Table 4.6. Some systems which had no reports filed are omitted. There are no discernible time-dependent trends among the systems identified. Most of the reports involved the following systems: reactor coolant (33.5%), instrumentation and controls (20.7%), engineered safety features (18.2%), and electrical power (12.2%). Each of these systems is discussed in the following subsections.

4.5.1.2.1 Reactor Coolant System. The designation of reactor coolant system encompasses a broad range of heat transfer related equipment in the reactor. For Millstone 1, this system includes all steam line monitors and valves, especially safety/relief valves; the isolation condenser; main steam isolation valves; pressure regulator; feedwater system and controls; and recirculation system. Over one-third (33.5%) of the reportable events involved the reactor coolant system (107 events). A large majority of reports involving the reactor coolant system concerned valve failures during tests, failures of the electrical and mechanical pressure regulators, and failures of various coolant parameter monitoring components. Excessive pipe movement was reported several times but no apparent damage resulted.

Eight weld related failures were reported for Millstone 1. Extensive work was performed on the feedwater spargers and all spargers have been replaced at least once. Cracks in BWRs are a common problem and Millstone 1 has been no exception. Cracking at Millstone 1 is analyzed in greater detail in Sect. 4.5.3.2.

The isolation condenser provided several problems at Millstone 1. The isolation condenser isolation valves failed during testing nine times. These failures are discussed in more detail in Sect. 4.5.3.3. The condenser itself had to be completely retubed in 1976 (RO 76-04). This incident is discussed in Sect. 4.5.2.1.

Table 4.6. Summary of systems involved in reportable events at Millstone 1

System	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Reactor	1	1	1	4			4	1	1	5	1	1	20
Reactor coolant	4	8	14	8	8	9	10	14	7	11	7	7	107
Engineered safety features		12	4	3	4	1	4	7	4	8	2	9	58
Instrumentation and controls		4	7	2		6	3	7	7	10	6	14	66
Electrical power	2	7	4	2		3	5	4	4	2		6	39
Fuel handling									1				1
Auxiliary water		4			1	3			1			1	10
Steam and power	3	3	1		1	1	1	1	3			1	15
Radiation protection								4		2	1	1	8
Radioactive waste management						2						2	4
No system applicable			1	1	2	1	1	1	2		1		10
Other Auxiliary systems										1		2	3
TOTAL	10	39	32	20	16	26	28	39	30	39	18	44	341

The electrical or mechanical pressure regulator failed four times from 1970 to 1972. Three of the failures involved only the electrical pressure regulator (AOs 71-12, 71-27, 72-2) and were inconsequential because the mechanical pressure regulator served as a backup. A fourth failure (AO-71-20) resulted in a reactor blowdown. This event is discussed in more detail in Sect. 4.5.2.4.

Along with resulting in a reactor blowdown, the above event was one of five that produced an excessive cooldown rate (AO 71-20, AO 75-09 LER 77-33, LER 79-05, LER 81-04). The October 10, 1971 blowdown cooled down the reactor vessel 135° in 18 min (450°F/h). The other excessive cooldown rates ranged from 105°F/h to 210°F/h. A rapid cooldown rate is of continuing concern due to the added stress placed on the reactor vessel.

On March 10, 1978, two uncontrolled blowdowns occurred. A review of the temperature charts for both blowdowns revealed that the average rate of reactor coolant temperature change, over 1 h, was less than technical specifications limit (100°F/h). The first blowdown resulted when a safety/relief valve failed to close. The reactor was manually scrammed. Reactor pressure was allowed to increase due to other activities in the plant. The same safety/relief valve lifted prematurely resulting in another blowdown.

4.5.1.2.2 <u>Instrumentation and control.</u> This system is comprised of all reactor safety and trip instrumentation as well as all control functions for normal operation. Its frequent appearance (20.7% or 66 events) as the system involved in reportable events can be attributed to instrumentation set point drift, miscalibration, and spurious trips. No safety functions were compromised as a result of these problems.

On August 18, 1981, the closure of a main steam isolation valve failed to generate a reactor protection system scram signal (LER 81-22). When the MSIV was closed, the relay did not deenergize. This prevented the reactor protection relay from deenergizing which in turn would prevent a scram. The armature on the limit switch was out of adjustment. An event of this nature occurred previously on June 18, 1981 (LER 81-16).

4.5.1.2.3 <u>Engineered safety features.</u> The engineered safety features system was involved in 58 of the reportable events (18.2%). Most failures occurred during testing of the ECCS and the isolation condenser. An unusually high number of reports appeared in 1971, when problems surfaced during tests of the core spray valves. On January 19, 1971, the core spray valves were tested at 1000 psig instead of the core spray operating pressure of 300 psig (AO 71-01). The valves all failed and the ECCS was declared inoperable. The torque sitting on the switches was too low and had to be reset. This event is described in further detail in Sect. 4.5.2. On March 31, 1971, the motor operator on an LPCI valve failed due to a short in its windings. The motor was replaced. On September 18, 1971, another LPCI valve motor operator burned out and was replaced by a larger motor.

Overall, 24 of the reportable events in this system resulted from human errors. Five of the events that resulted from human errors are of interest. On April 19, 1981, maintenance personnel left two containment isolation valves in the closed position (LER 81-03). The closure of these valves isolated the high drywell pressure switch associated with the ECCS and RPS initiation. While investigating problems with a LPCI motor operated valve, a maintenance foreman opened the wrong breaker (RO 77-38). The open breaker caused a LPCI injection valve to become inoperable. Defective procedures allowed the boron concentration in the standby liquid control tanks to be less than the technical specifications limit (LER 79-18). On September 14, 1979, personnel discovered a design error in the power distribution to the ECCS buses (LER 79-26). A loss of power could occur to the supply for the ECCS electrical buses without the loss of normal power initiation logic being able to sense the loss. The fifth event was the previously mentioned event on January 19, 1971 (AO 71-01). Four core spray valves failed when the system was tested at 100 psig rather than its operating pressure of 300 psig.

4.5.1.2.4 Electrical power system. Twenty-eight of the 39 reportable events concerning the electrical power systems were attributed to failures of the gas turbine generator. These failures in the electrical power system comprised 12.2% of all reported events for Millstone 1.

The emergency power system consists of a gas turbine generator and a diesel generator. Upon loss of offsite power, the gas turbine generator is required to supply power to the FWCI system. Therefore, when the gas turbine generator fails, the FWCI system is unavailable. The FWCI system or the isolation condenser are provisions for emergency core cooling during a loss of normal auxiliary power. On two occasions (RO 76-10, RO 76-12) the gas turbine generator was declared inoperable while the isolation condenser was out of service. The plant was immediately shut down on both occasions. Further details are given in Sect. 4.5.2 and Sect. 4.5.3.

On December 10, 1977, the diesel generator was declared inoperable while the gas turbine generator was out of service (RO 77-39). Consequently, all emergency power systems were unavailable. Further investigation of the emergency power system on April 3, 1981 revealed that a single failure mode existed (LER 81-02). A single relay failure in the loss of normal power circuits would inhibit the diesel generator and the gas turbine generator from loading the emergency buses.

Millstone also experienced a loss of offsite power when salt built up on the 345 kV lines and insulators as hurricane Belle passed (RO 76-29). The diesel generator and gas turbine generator were being run without loads as a precaution. When normal power was lost, the gas turbine tripped and the diesel generator loaded the emergency buses. The gas turbine tripped twice. The first trip was due to a loss of the AC auxiliaries due to the loss of offsite power. The second trip was attributable to a loss of DC control power caused by the gas turbine running on DC auxiliaries which it is not designed to do. For further details, see Sect. 4.5.2.

4.5.1.3 Causes of reportable events. Table 4.7 presents a summary of causes of reportable events at Millstone 1. Over half of all reportable events at the plant were attributed to inherent failure. Inherent failure includes set point drifts, wear out, and many of the failures for which no cause could be found.

Over the operating experience reviewed, human error was responsible for almost half of all reportable events (144 events). Administrative, design, fabrication, installation, maintenance, and operator errors are

Table 4.7. Causes of Reportable events for Millstone 1

Cause	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
Administrative		1				2	2	1	1	2		2	11
Design	4	8	3	2	4	3	4	4	2	2	2	3	41
Fabrication											1		1
Inherent failure	2	8	19	10	7	15	13	24	16	24	9	33	180
Installation	3	5	2	1	1	2	2	2	1	3	2		24
Lightning		1											1
Maintenance	1	6	7	6	4	5	7	4	8	2	3	3	56
Operator	1	2		1			1	1		2		3	11
Weather								1					1
TOTAL	11	31	31	20	16	27	29	37	28	35	17	44	326

all considered human errors. Human errors played an important role in events categorized as significant at Millstone 1. These human errors involved design, administrative, and maintenance errors. An examination of causes of significant events revealed that 10 of the 12 significant events were attributed to human errors. The last 2 events were inherent failures.

4.5.1.4 Events of environmental importance

4.5.1.4.1 Radioactivity release events. Eleven events at Millstone 1 resulted in radioactive releases. Table 4.8 summarizes the amount of radiation released annually from the plant. Six of the 11 reported release events were caused by mishandling or failures of the waste disposal system. The remaining five events involved inadvertent exposures of maintenance workers. The quarterly release rate was exceeded four times during the period of 1976 to 1979.

Table 4.9 summarizes the events concerning radiation releses or personnel exposures at Millstone. Human errors caused 10 of the 11 events. The last release event was considered inherent in BWRs. On December 13, 1977, two hydrogen explosions occurred in the off-gas system. It was the second explosion that caused a small, uncontrolled release of radiation. For further details of this event, see Sect. 4.5.

On March 25, 1974, two workers were overexposed to Co-58 and Co-60 due to poor ventilation in a maintenance area. Also, badge readings during the fall 1974 refueling outage showed that three men had exceeded their dose limits. An overflow of a surge tank onto the boiler room floor contaminated the shoes of a worker on March 27, 1975. In September, 1975, one worker ingested small amounts (<1500 nanocuries) of Co-60 and Mn-54. In October, 1975 five workers received excess doses of radiation while performing maintenance on the feedwater spargers.

Throughout the ten years of operating experience there were nine reports of excess radioactivity in plants and animals near the Millstone site. Most of these involved high levels of activity in the oysters in Niantic Bay. One report, however, revealed a high iodine activity in cow's milk samples taken from the area. This was attributed to fallout from the Chinese atomic bomb tests.

4.5.1.4.2 Nonradiological events. The only nonradiological environmental events consisted of the impingement of species of fish on intake screen above prescribed limits. There were 18 reports of excess fish impingement, 16 in 1976, two in 1977. The unusually high numbers were attributed to an abnormal increase in fish population in 1976 and 1977.

4.5.2 Review of significant events

The analysis of the operating history of Millstone 1 examined reported events to find those occurrences which represented significant threats to continued safe operation or to systems designed to mitigate transient conditions. Reportable events were therefore significant if they met one of these criteria:

Table 4.8. Summary of radioactivity released from Millstone 1

Release (curies)	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981[a]
Airborne:												
Total noble gases	4.1E+2	2.76E+5	7.26E+5	7.90E+4	9.12E+5	2.97E+6	5.07E+5	6.20E+5	5.66E+5	2.06E+4	1.19E+4	2.04E+2
Total I-131	3.2E-10		1.23E+0	1.54E-1	3.18E+0	9.77E+0	2.19E+0	4.66E+0	3.19E+0	4.01E-1	2.14E-1	1.06E-3
Total halogens	NA	3.94E+0	1.23E+0	1.54E-1	3.18E+0	6.29E+1	3.65E+1	6.10E+1	3.19E+0	4.01E-1	3.16E+0	2.36E-2
Total particulates	NA	5.87E-2	8.75E-6	4.10E-2	8.77E-2	1.88E-1	1.49E-1	2.01E-1	1.36E+0	1.89E-1	1.13E-1	9.92E-3
Total tritium	NA	3.21E+0	4.21E+0	1.69E+0	7.85E+0	1.72E+1	2.87E+1	6.52E+1	3.36E+1	5.30E+1	9.55E+1	3.69E+1
Liquid:												
Total mixed products	NA	1.97E+1	5.15E+1	3.34E+1	1.98E+2	1.99E+2	9.65E+0	5.27E-1	1.74E-1	2.09E-1	7.16E-1	3.56E-1
Total tritium	NA	1.27E+1	2.09E+1	3.70E+0	2.41E+1	8.03E+1	2.01E+1	4.41E+0	2.22E+0	7.92E+0	2.73E+1	2.30E+0
Total noble gases	NA	NA	0	0	0	1.11E+1	3.56E-1	3.67E-1	7.65E-1	7.00E-1	4.92E-1	1.62E-2
Solid:												
Total	1.1E+0	2.61E+2	1.64E+3	1.51E+3	2.57E+3	2.58E+3	1.70E+3	3.03E+3	8.15E+4	1.16E+3	4.66E+3	NA

[a] First half of year.

Table 4.9. Events of radiation releases or personnel exposures at Millstone 1

Number	NSIC number	Event date	Cause	Description
	115103	3/25/74	A	Three workers were overexposed due to poor ventilation in area
	115107	1974	A	Badge readings showed three men exceeded their dose limits
AO 75-5	101408	3/27/75	E	Wiring error caused flow of contaminate into boiler system
AO 75-6	101701	3/30/75	A	Inadvertent discharge of radioactive liquid to environment
	115105	9/75	H	Worker exposed to airborne activity. Did not have work permit
	115106	10/75	H	Two workers exposed to airborne activity. Exhaust trunk was not operating
	120229	11/76	B	Two unmonitored liquid release paths discovered
RO 76-17	113540	4/23/76	B	Noble gas release rate exceeded limits
RO 77-40	144186	12/13/77	D	Two hydrogen explosions caused excessive release out the stack
LER 81-02E	167613	6/22/81	H	Unmonitored radioactive liquid waste released
LER 81-03E	168043	8/13/81	H	Unmonitored release of liquid effluent

1. an event in which the failure or failures initiated a design basis event (DBE) as listed in Table 3.1, or
2. an event in which the failure or failures compromised a function of the engineered safety features.

Thirteen events at Millstone 1 met the above significance criteria. Tables 4.10 and 4.11 summarize the significant categories assigned to these events and Table 4.11 summarizes the significant events which occurred at Millstone 1. The total in the table, 19, is greater than the actual number of significant events, 13, because 5 events (Ltr., RO 76-10, RO 76-12, RO 76-29, and RO 77-39), required multiple significance categories. The events designated as significant were:

1. loss of the isolation condenser (1),
2. provisions for emergency core cooling during a loss of normal power lost (2),
3. ECCS failures (2),
4. loss of offsite power with partial loss of emergency power (1),
5. complete and potential loss of emergency power (2),
6. inadvertent criticality (1),
7. all control rod drive accumulators require replacement (1),
8. recirculation pumps trip with no alarm given (1),
9. loss of pressure control followed by a blowdown (1), and
10. hydrogen explosion in the off-gas system (1).

4.5.2.1 Isolation condenser failure. On February 12, 1976, the plant shut down due to arcing of the main transformer during a storm.[18,19] Normal post shutdown pressure transients caused the main steam isolation valves to close. As a result of this, pressure increased momentarily in the isolation condenser, causing a tube in the condenser to fail (RO 76-04).

Steam leaked into the shell side of the condenser and was vented into the atmosphere. The operators did not recognize the cause of the steam release until 1 h and 16 min after the shutdown, when the control room received a high radiation alarm from the steam vent line. The isolation condenser was then isolated and the steam releases halted.

An area of approximately one acre, all inside the fenced area, was contaminated. No reportable personnel exposures resulted from the release of contaminants. Eight minutes after the reactor trip, the main condenser was valved in to act as a primary heat sink. Recovery from the transient proceeded smoothly.

Examination of the condenser revealed a tube with a 1-in. by 2-in. hole. The failure resulted from stress corrosion cracking. The corrosion was attributed to the intrusion of chlorine from a previous failure of the main condenser. Other tubes in the isolation condenser was retubed with Inconel 600 tube material.

The isolation condenser at Millstone serves as the equivalent to a reactor core isolation cooling (RCIC) system and, thus, is an engineered safety feature.

4.5.2.2 Provisions for emergency core cooling during a loss of normal auxiliary power loss. During a loss of offsite power, two methods of

Table 4.10. Summary of significant events at Millstone 1

Significance category	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	Total
S1							2	1					3
S2				1			1						2
S3													0
S4												1	1
S5													0
S6													0
S7		2		1			5			1		1	11
S8							2	1					2
S9													0
TOTAL	0	2	0	2	0	0	10	2	0	1	0	2	19

Table 4.11. Tabulation of significant events at Millstone 1

Report section	Report number	Accession number	Significance	Event description
4.5.2.3	AO 71-01	62296	S7	Four simultaneous valve failures render ECCS inoperable
4.5.2.9	AO 71-20	66996	S7	Failure of steam turbine bypass valve caused a blowdown
4.5.2.7		77956	S7, S2	All control rod drive accumulators require replacement
4.5.2.1	RO 76-04	111647	S7	Tube failures in Isolation Condenser resulted in radiation release
4.5.2.2	RO 76-10	112309	S7, S1	Gas turbine generator inoperable while Isolation Condenser inoperable
4.5.2.2	RO 76-12	112310	S7, S1	Gas turbine generator inoperable while Isolation Condenser inoperable
4.5.2.4	RO 76-29	116780	S7, S8	Gas turbine generator tripped on incorrect feed during a LOOP
4.5.2.6	RO 76-34	120436	S8	Unplanned criticality achieved when wrong control rods selected
4.5.2.5	RO 77-39	144187	S7, S1	Diesel generator and gas turbine generator inoperable simultaneously
4.5.2.10	RO 77-40	144186	S9	Two hydrogen explosions in the off-gas system occurred
4.5.2.3	LER 79-26	151912	S7	Potential existed for loss of power to ECCS to go undetected
4.5.2.5	LER 81-02	165884	S7	Potential existed for a single failure mode in the emergency power system
4.5.2.8	LER 81-25	169185	S4	Both recirculation pumps tripped, ATWS isolated, no alarm

heat removal are available. Either the isolation condenser or the feedwater coolant injection system (FWCI) in conjunction with the pressure relief valves can remove decay heat.[20] The isolation condenser system operates by natural circulation without the need for driving power other than the DC electrical system used to place the system in operation. The operation of the FWCI system requires an AC power source. Given the loss of offsite power, the gas turbine generator provides the driving force to the FWCI system. The loss of the gas turbine generator would mean the loss of the FWCI system, one loop of the LPCI system and one loop of the core spray system.

On two occasions within a one week period, the gas turbine generator and the isolation condenser were unavailable simultaneously (RO 76-10, RO 76-12). Consequently, the FWCI and isolation condenser were simultaneously unavailable.[21] The isolation condenser system was inoperable due to retubing activities required after the pressure transient on February 12, 1976 (see Sect. 4.5.2.1). On March 8, the gas turbine generator failed to start due to a maladjusted governor. The governor being out of adjustment was attributed to the higher test frequency of the gas turbine while the isolation condenser was operable. The governor was readjusted and the gas turbine declared operable after a successful test.

On March 15, the gas turbine again failed to start due to problems with the governor. The electric governor-magnetic board which provides signal conditioning of various input signals and an output signal to the gas turbine speed control system failed. The failure was due to the higher test frequency of the gas turbine generator.

4.5.2.3 <u>ECCS failures.</u> Two events challenged the integrity of the ECCS. On January 19, 1971, operability tests of the core spray and LPCI systems revealed several component failures. Two core spray injection valves, one on each core spray loop, failed. Testing of the LPCI system revealed two other valves that would not operate properly. After discovering these failed valves, a turbine control valve unexpectedly closed completely with the reactor at full power. The other three turbine control valves opened wider to compensate. Pressure oscillations of 25% caused reactor power fluctuations of 8%. As soon as control was switched from the mechanical pressure regulator to the electrical pressure regulator, the oscillations stopped. The four valves in the ECCS failed because their torque switches were set too low.[22]

The LPCI system and both core spray loops are all capable of supplying emergency cooling during a large line break with or without normal offsite power. If offsite power is lost, either the standby diesel generator or the gas turbine generator must be available. Hence, given a large pipe rupture, one of the three aforementioned systems must be available. On January 19, 1971, the integrity of each system was suspect.

On September 14, 1979, a situation arose that was not specifically considered in the safety analysis report. A review of the control circuitry and logic associated with the 4160 V circuit breakers, revealed that a loss of power could occur to the supply for the ECCS electrical buses. The Loss of Normal Power (LNP) initiation logic senses the loss of power and immediately starts the emergency power sources. With the design error in the logic system, the loss of power would not have been sensed and the emergency power system would not automatically start. A modification to the LNP initiation logic corrected the design error.

4.5.2.4 Loss of offsite power with partial loss of emergency power. On August 10, 1976 the Millstone 1 plant lost all offsite power due to salt buildup on the 354 KV lines and insulators.[23] Prior to the loss of power the gas turbine generator and the diesel generator were running without a load, as a precaution during storm conditions. The plant was operating at 45% power and tripped during the loss of offsite power. The gas turbine generator failed on the loss of normal power; however, the diesel generator accepted load successfully. The gas turbine generator restarted and ran for ~8 min before tripping again (RO 76-29).[21]

Investigation revealed that operator error caused both failures of the gas turbine generator. The generator has both AC and DC auxiliaries. The gas turbine generator is the primary source of AC power for its own auxiliaries once it is up to rated speed and voltage. The design also provides for an alternate source of AC power during testing. Transfer between the two sources of power is accomplished by a manually operated throwover switch.

During precautionary operation of the gas turbine generator, the operators performed a bimonthly surveillance test using the alternate source of AC power. At the conclusion of the test the throwover switch was not returned to its normal (primary source) position. Upon loss of offsite power and unit trip, the alternate source of AC power was lost causing the gas turbine generator to trip.

In its normal position, the throwover switch also enables automatic transfer from the DC auxiliaries (only used to start the unit) to the AC auxiliaries. The unit restarted after the initial trip. Transfer from DC auxiliaries to AC was not accomplished. The unit ran for 8 min then tripped a second time when the DC batteries failed.

Recurrence of the event was mitigated by the following corrective actions:[24]

1. The procedure for testing the gas turbine was rewritten so that the AC auxiliaries are energized from the primary source during surveillance testing.
2. The throwover switch was locked into its normal position.
3. A breaker position monitoring circuit was installed to alert the operators of an incorrect alignment of the power sources for the AC auxiliaries.

The gas turbine generator serves as the emergency power source of 4.16 KV power for the feedwater coolant injection (FWCI), pumps and control, which are part of the ECCS. This event seriously compromised the safety of the plant. For over 3 h the lone diesel generator was the only source of power to Millstone 1. The isolation condenser, which requires only DC power to place it in service, was used to cool the core. The isolation condenser had experienced severe problems only 6 months prior to this incident (see Sect. 4.5.1.1). Had it failed during the loss of normal power, the diesel generator would have carried the entire burden of supplying power for cooling the core via the low pressure ECCS. In general, diesel generators have had historically high failure rates; however, the lone diesel one at Millstone 1 has a very good performance record.

4.5.2.5 Potential complete loss of emergency power. Millstone 1 experienced one complete loss of emergency power and later discovered that a single failure mode existed in the emergency power system. On December 10, 1977, a test of the FWCI system revealed a fault in the gas turbine generator's governor (RO-77-39). Since the emergency power system consists of the gas turbine generator and a diesel generator, the diesel generator was tested for operability. The diesel generator failed the operability test.[21] The cause was unknown.

The single failure point in the emergency power system was discovered through a fault tree analysis of the electrical control circuitry (LER 81-02). The analysis identified that the potential existed for a single relay failure in either of the two LNP circuits to prevent both the gas turbine generator and the diesel generator from energizing the 4160 V emergency buses. The relay failure would occur if the contacts of the time delay relay in either LNP circuit failed to reopen following a loss of normal power initiation signal. This would result in a continuous trip signal to all 4160 V and certain 480 V circuit breakers. In this situation, the buses could be energized by removing the control circuit fuses and manually operating the circuit breakers. The installation of a second time delay relay corrected the design error.

4.5.2.6 Inadvertent criticality. While performing a shutdown margin test on November 12, 1976, an inadvertent criticality and reactor trip occurred (RO 76-34). An operator error in selecting rods for the test caused the unplanned criticality.[25]

The test is performed by positioning the highest worth rod (46-23) to notch position 10, the diagonal control rod (42-19) is then withdrawn to notch position 10, followed by full withdrawal of the maximum worth rod. The licensed reactor operator incorrectly notched out adjacent control rod 46-19 (instead of 42-19, the correct and designated rod). Without recognizing his selection error, he then withdrew the highest worth rod. The reactor tripped on high flux.

At the time of the incident the rod worth minimizer had been bypassed and the operator was performing the test by himself — a violation of test procedures. The circumstances of the trip were reported to the supervisor who dismissed the condition as "spurious noise." Per NRC, normal procedures should be that the operator believe all instrument indications as true, unless proved otherwise.[26]

A second test was performed contrary to procedural requirements concerning evaluation of instrumentation. Again, the operator erroneously withdrew rod 46-19. Subsequent withdrawal of rod 46-23 resulted in a flux increase, and the high worth rod was reinserted to avert a second trip. Following the recognition of the previous rod selection errors, a third shutdown margin test was successfully performed. Procedural requirements were again violated as the third test was performed without assessing the potential for radiation exposure or fuel damage caused by the two criticalities. The incident was not reported to the appropriate management personnel until their arrival on the next work day, another violation of procedures.

Refueling and fuel movement were suspended for three days by the NRC. No personnel exposures occurred. The licenses of the two operatores involved were suspended.

This incident represents the only major operator error committed over the operating experience of Millstone 1. The multiple procedural errors resulted in a $15,000 fine.

4.5.2.7 <u>All control rod drive accumulators replaced.</u> In January, 1973, two accumulators gave indications of leaking water into the instrumentation block (Ltr. 1/26/73). Investigation revealed that the nickel and chromium plating had flaked from areas of the inner walls of the two accumulators. The discovery prompted the inspection of the other 143 accumulators. All had at least minor plating defects, most of which were blisters or pits. Only six of the accumulators had amounts of blistering or flaking that were sufficient to possibly impair the operation of the control rod drive mechanism. These six were replaced with new ones. Flushing the entire control rod drive hydraulic system cleaned the system of foreign particles. Millstone 1 implemented a program for close monitoring of the instrumentation and promptly investigating any abnormalities in the system.[14] No events of this type have occurred since the new program was implemented.

4.5.2.8 <u>Recirculation pumps trip with no alarm.</u> On September 15, 1981, voltage fluctuations in the 125 V DC electrical system resulted in spurious isolation of the Anticipated Transient Without Scram (ATWS) system (LER 81-25). Reenergizing the ATWS system caused an automatic trip of both recirculation pumps. Since the pumps were operating at minimum speed (reactor power was at 1%), pump coastdown and natural circulation maintained recirculation flow. With no significant change in the differential pressure across the recirculation pumps and no annunciated alarm for recirculation pump trip, control room personnel were not immediately aware of the event.

The forced recirculation flow is required to provide mixing of feedwater entering the reactor vessel to mitigate the consequences of rapid changes in reactor moderator density. The flow also eliminates the potential for high local reactor vessel stresses due to thermal stratification of reactor coolant. Although natural circulation flow provides some mixing, forced circulation is required to maintain the parameters within acceptable limits at high power levels. The effects of no forced circulation were analyzed with respect to fuel and reactor vessel thermal effects for this event. The effects were negligible due to the low reactor power level and the short amount of time at which there was no forced circulation flow before the reactor scram occurred. An annunciator was installed off the recirculation pump field breaker to alert control room personnel of a recirculation pump trip. Additionally, after the ATWS system isolates, operator action is required to reset the system.

4.5.2.9 <u>Pressure transient and blowdown.</u> On October 10, 1971 the Millstone 1 plant experienced a pressure transient followed by a blowdown of 75,000 gal of water to the torus (RO 71-20).[11,17] With the reactor at 100% power, the electric pressure regulator caused the pressure to rise to 1040 psig. The operator placed the mechanical pressure regulator into service, but this did not mitigate the transient. The reactor scrammed on a high flux reading on the average power range monitor (APRM). The turbine tripped and the turbine bypass valve opened. As the pressure of the vessel began to drop, the number one turbine valve failed to close. The main steam isolation valves closed but pressure continued to decrease in the vessel. It was then discovered that a relief valve that opened at the time of the scram failed to reseat.

The stuck-open valve seated when pressure dropped to 263 psig. The isolation condenser was then put into a service and normal cooldown proceeded.

During the transient the reactor pressure dropped from 1040 psig to 263 psig and the moderator temperature dropped from 525°F to 390°F in 18 min. This represents a significant stress on the vessel even though no technical specifications were violated. General Electric determined that the vessel blowdown conditions would not affect the integrity of the vessel.

Failure of the electric pressure relief valve was attributed to a loose dashpot connection to the pressure regulator torque tube.

The relief valve itself experienced two failures. First, the valve opened at 1040 psig, instead of 1095 psig. The set point change was caused by relaxation of the set pressure-adjustment spring due to its exposure to temperatures near 550°F. The valves had been insulated with asbestos blankets, and the reduction in heat transfer ability caused the valve internals to be exposed to elevated temperatures. This insulation was partially removed. Second, the relief valve failed to reseat after opening. This was attributed to leaking of the pilot valve (caused by lower setpoint) and the erosion of pilot-valve disk.

4.5.2.10 <u>Hydrogen explosions in off-gas system.</u> On December 13, 1977, two hydrogen explosions occurred at Millstone 1.[38] The first explosion occurred at 9:30 a.m. and was mostly confined to the off-gas system. Damage was minor and the plant reduced power while repairs commenced. A second explosion occurred at 1:00 p.m., outside the off-gas system, causing considerably more damage and injuring personnel.

The second explosion occurred when the Millstone personnel were unsuccessful in restoring water to the loop seals after the first explosion. Without these seals, the gas accumulated and was ignited by a spark from the liquid level switch in the stack base sump. The explosion propelled the door of the room into a warehouse 60 m away, breached the reinforced-concrete ceiling of the room at the base of the stack, extensively damaged the ceiling beams, damaged supports of a radiation monitor for the stack, and cracked the stack. The control room was alerted to the second detonation and the operators manually tripped the plant, terminating the generation of hydrogen in the core. The second explosion injured one man and resulted in a small, uncontrolled release of radiation.

This is a generic problem in BWRs, but most explosions are confined inside the off-gas system, which is designed to mitigate the effects of a detonation. However, explosions outside the system have occurred, resulting in far more damage to equipment and structures.[39]

Immediately after the event, the NRC required that all BWR licensees take steps to correct five identified deficiencies in the off-gas system, with particular attention being paid to the loop seals.

1. Review the operations and maintenance procedures of the off-gas system to assure operation in accordance with all design parameters.
2. Review the adequacy of the ventilation of spaces and areas where there is piping containing explosive gases.
3. For those spaces identified, describe what action has been taken to ensure that explosive mixtures cannot accumulate, that monitoring equipment would warn of such an accumulation should it occur.

4. Describe the design features that minimize and detect the loss of liquid from loop seals, and describe operating procedures that ensure prompt detection and resealing of blown seals.
5. Review operating and emergency procedures to ensure that the operating staff has adequate guidance to respond properly to off-gas system explosions.

4.5.3 Trends and safety implications of reportable events

Using the systems involved in reportable events listed in Table 4.2, specific trends and problem areas were identified for safety-related functions: (1) partial loss of emergency power, (2) pipe cracks, (3) isolation condenser valving problems, (4) MSIV failures, and (5) excessive reactor cooldown rates.

4.5.3.1 Partial loss of emergency power. Millstone 1 has experienced 36 failures of the emergency generator systems and controls. Gas turbine generator failure was the dominant contributor to degradation of the emergency power system. The gas turbine generator failed to start or run its mission 28 times. Five of these were failures on demand, the remainder occurred under test conditions. Appendix B provides a description of the 28 gas turbine generator failures, along with corrective actions taken to restore the unit to service.

An analysis of gas turbine generator failures reveals that 7 of the 28 failures were attributed to a faulty speed switch. This switch was totally replaced four times during the 11-year history of the plant. The most recent replacement was required in February, 1979. Five of the failures of the unit were attributed to operator or procedural error. Procedural error caused the most significant failure of the gas turbine generator (AO 76-29) described in more detail in Sect. 4.5.1.2.

The emergency power system at Millstone 1 consists of one diesel generator and one gas turbine generator. If normal power to the plant is lost, the FWCI can be powered only by the gas turbine generator. Failure of the gas turbine, therefore, eliminates the cooling capacity of the FWCI. The plant does have the use of an isolation condenser at all times, even during a loss of all AC power. Unit 1 currently has use of the diesel generators at unit 2, but technical specifications do not take credit for these as a source of emergency power.

The plant is located on a point and all power lines must share the same right of way for several miles. This increases the chance of losing all offsite power due to common mode failures. In light of the numerous failures of the gas turbine generator and the high potential for common mode loss of offsite power, the performance of the emergency power system should be examined in greater detail. Despite the potential for loss of emergency power, the Millstone 1 plant has experienced remarkably few failures of its diesel generator and only one complete loss of offsite power (AO 76-29).

4.5.3.2 Pipe cracks. Millstone 1 reported eight incidents of pipe cracking. Pipe cracks have always been a generic problem in BWRs.[30] The most significant cracking events occurred in 1972, 1976, and 1980. However, no safety related incident occurred at the plant as a result of pipe cracking.

In 1972 the cracks were detected in the feedwater spargers. Subsequently, all spargers were replaced, a task which resulted in excessive down time for the plant. In 1976 a weld leak was found in the head spray system. The failure was attributed to stress corrosion cracking, and cracked components were replaced. In 1980 cracks were found in two main steam line supports and in a condenser nozzle. The condenser nozzle-to-steam supply weld cracked due to stress corrosion and was replaced. The two cracks in the main steam line supports were attributed to inadequate welds during installation. The supports were reinstalled.

4.5.3.3 Isolation condenser valve failures. Millstone 1 has experienced ten failures of the isolation condenser valves over the time period from 1970 to 1981. The condenser isolated twice as it was placed in operation (AOs 70-5, 73-4). Both times the inboard condensate return valve was opened too wide and caused excessively high flow through the condenser. This high flow condition automatically isolates the condenser. After the first occurrence, the valve opening was restricted to reduce flow to the isolation condenser. The second failure occurred when a maintenance worker failed to properly set the valve opening restrictor after working on the valve.

Five failures have occurred with the inboard steam supply valve (1-IC-1). On December 17, 1976, the torque switch actuator setting was found to be incorrect, actuating the torque switch prematurely and not allowing the valve to move. On October 31, 1977 the breaker for the valve malfunctioned, causing the valve to be inoperable. On February 14, 1979 the valve operator gear casing was fractured, causing inoperability of the valve. On December 17, 1976, a faulty microswitch on the closing torque switch caused the valve to fail to close. This identical incident recurred on September 4, 1979. All of these failures occurred during surveillance testing, and the plant was immediately shut down after each failure.

On October 19, 1978, the condensate return isolation valve spuriously opened causing an inadvertent initiation of the isolation condenser. The initiation was then secured by an operator who closed the valve. The spurious opening signal resulted from a set point drift of two switches in separate logic channels. The set points were subsequently readjusted. On December 18, 1976 the isolation condenser inboard condensate return failed to close during a test. The torque switch setting was incorrect and was readjusted. On December 3, 1981, the isolation condenser had a valve motor fail.

4.5.3.4 Main steam isolation valve failures. Eight of the reportable events occurred due to MSIV failures. Based upon the data available in the LER data files, recent MSIV failures are primarily related to the following causes: (1) poor quality control air to the pilot valves, and (2) binding of MSIV valve stems with the valve stem packing.[31] These two failure modes are significant in that: (1) they identify mechanisms by which more than one MSIV may fail to close at the same time, and (2) they continue to occur even though corrective actions indicate that the technology is available to prevent such failures. At Millstone 1, four of the MSIV failures were failure to close with three of these due to sticking air slide valves. The fourth failure to close was due to a parted venting slide valve. Three failures (RO 75-29, LER 79-11, LER 80-14) were

MSIV related failures but not valve failures. In 1975, a valve position switch was in the wrong position due to a relay that failed to close. A relay failed to de-energize in 1979 due to a maladjustment of the relay limit switch. The last MSIV related failure was the failure rate test performed on two MSIVs (LER 80-14).

The last actual valve failure occurred in 1974. It appears as though the air supply to the valves has been kept clean, or the frequency of maintenance and testing of the valves has increased.

4.5.3.5 Excessive reactor cooldown rates. Millstone experienced five incidents of excessive cooldown rates throughout its operating history. Any large cooldown rate is of concern since a thermal stress is placed on the reactor vessel and the resulting fatique is a cumulative effect. The first and most significant cooldown occurred in 1971 (AO 71-20). The cooldown rate was equivalent to 450°F/h and 75,000 gal. of water was blown out of the system (see Sect. 4.5.2). The other four blowdowns that resulted in excessive cooldown rates occurred in 1975, 1977, 1979 and 1981 (RO 75-09, RO 77-33, LER 79-05, and LER 81-04, respectively). The cooldown rates ranged from 105 to 210°F/h. Three additional blowdowns occurred during the operating history but the cooldown rate for each occurrence was below the Tech. Spec. limit of 100°F/h (RO 77-17 and RO 78-04 with 2 blowdowns).

Four of the excessive cooldown rates occurred due to safety-relief valve failures (as well as the other three blowdown events). Overall, twelve events occurred due to safety/relief valve failures. Half of the events produced no deleterious effects to the operation of the plant or the environment. Failures included fouled instrument air lines, a clogged filter, wiring short, valve failing to open, or setpoint drift. The other six events resulted in blowdowns with four of these producing excessive cooldown rates. On March 10, 1978, two blowdowns occurred but a review of the temperature charts revealed that the cooldown rate was not exceeded. Therefore, the six events represent seven blowdowns and excessive cooldowns. The failure modes of the safety which valves fell into two categories. The valve either lifted prematurely (4 occasions), or failed to close (3).

4.6 Evaluation of Operating Experience

The overall review of operating experience at Millstone 1 is based on information contained in two generic sources: reports of forced shutdowns and power reductions, and a compilation of reportable occurrences. Each category was reviewed by a separate reviewer with periodic discussions of observations between reviewers.

Equipment failure was the dominant cause of forced shutdowns at Millstone 1. This includes both component and instrumentation failures. Relatively few shutdowns were initiated by human errors. During the first few years of operation, problems with the level controller on the moisture separator between the high and low side of the main turbine forced the plant to shut down often. The plant was also plagued with corrosion failures of tube bundles, beginning with chlorine intrusion of the main condenser in 1972. The chlorine was never completely purged from the coolant system, causing corrosion problems in various other system components, some of them appearing years later. General Electric installed completely redesigned equipment, built with a more prudent choice of metals, and the problem seems to have disappeared.

Roughly half of all reportable events were caused by human errors. Even though Millstone 1 experienced a large number of human errors, procedural errors did not really contribute to overall number of events. No discernable time trends appeared in the number of reportable events. Human error was also the major contributor to the significant events (11 of 13). The cause of design errors dominated human errors (7). The other two significant events were caused by equipment failures in the emergency power system. Only three of the significant events occurred prior to 1976 with five occurring in 1976. There were two significant events in 1977, one in 1979 and two in 1981.

The operational history of Millstone 1 revealed several types of recurring events. Some of the recurring problems have been resolved while others continue. Pipe cracking, a generic problem in BWRs, was experienced at Millstone. Eight incidents of pipe cracking were reported with the most significant events occuring in 1972, 1976 and 1980. In 1972, cracks were found in the feedwater spargers. Cracks in the core spray system and main steam line were discovered in 1976 and 1980, respectively. No pipe cracking was discovered in 1981.

Main steam isolation valve failures, another generic problem, also occurred at Millstone 1 (8 events). Three failures were MSIV related, but were not actual valve failures. The failure modes of the MSIVs included: failure to close due to sticking air slide valves (3), failure to close due to failed venting slide valve (1), and failure to close due to a missing spring (1). The last actual MSIV failure was in 1974. The problem appears to have been resolved through ensuring a cleaner air supply to the valves, or an increased testing and maintenance frequency.

Three of the problems which should be of continued concern are isolation condenser valve failures, emergency power system failures, and incidents resulting in excessive blowdown rates because of safety and relief valve failures.

Ten isolation condenser valve failures have occurred during the 11-year history of Millstone 1. On two occasions, the isolation condenser became isolated. Both times the inboard condensate return valve was opened too wide causing excessively high flow rates through the condenser. The inborad steam supply valve (1-IC-1) failed five times between 1976 and 1979. Other failures consisted of a spurious opening of a condensate return isolation valve, failing of an inboard condensate return valve to close, and a valve motor failing.

Further examination of the isolation condenser valves is warranted in view the number of failures of the various valves and the function of the isolation condenser to provide removal of afterheat from the core.

The operability of the emergency power system was challenged on several occasions. The emergency power system consists of one diesel generator and one gas turbine generator. If normal power is lost, the gas turbine is the sole source of power for the FWCI system. The gas turbine failed to start or run for its entire mission 28 times. On two occasions, the gas turbine failed while the isolation condenser was unavailable. During a loss of offsite power, the diesel generator was the only source of emergency power since the gas turbine generator tripped on an incorrect feed. The performance of the gas turbine generator should be examined in greater detail based on its observed reliability characteristics. Additionally, the importance of the onsite power systems is increased since all offsite power lines must share the same right-of-way for several miles. This increases the probability of losing all offsite power due to a common mode failure.

Excessive cooldown rates are of concern due to the added thermal stress placed upon the reactor vessel and coolant piping. The added importance results from the cumulative effect of the fatigue. Millstone 1 experienced five excessive thermal transients in eight blowdowns due to safety/relief valve failures. The cooldown rates during the transients ranged from 105 to 450°F/h. Since 1975, the transients have recurred at a greater rate than one every two years. Due to the increased recurrence rate, the problem of resulting excessive cooldown rates due to safety/relief valve failures should also be of continued concern.

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Appendix A: Millstone 1

Part 1. Forced Shutdown and Power Reduction Tables

Table A1.1 1970 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1970)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	11/19	16	NA	RO 70-04	Momentary main steam line high flow signal.	B	3	Reactor Coolant (CD)	Instrumentation & Controls	D1.3
2	11/21	11	NA		Reactor mode switch wiggling resulted in main steam isolation.	B	3	Reactor Coolant (CD)	Instrumentation & Controls	D2.1
3	12/5	2	0		Electrical pressure regulator pressure control oscillation caused spurious low level indication.	B	3	Steam & Power (HA)	Instrumentation & Controls	D1.3
4	12/22	2	15		Packing leak on isolation condenser steam supply valve.	B	1	Reactor Coolant (CE)	Valves	N1.1.4
5	12/23	24	0	AO 70-08	Cracked weld on main condenser.	B	1	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
6	12/29	23	0	AO 70-09	Pressure control bypass valve linkage torn from its support.	B	1	Steam & Power (HE)	Valves	N1.1
7	12/30	1	13		Turbine trip due to high level in moisture separator drain tank.	B	3	Steam & Power (HA)	Turbines	D2.3

Table A1.2 1971 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	1/2	1	40		Turbine trip due to high level in moisture separator drain tank.	A	3	Steam & Power (HA)	Turbines	D2.3
2	1/2	7	11.5		Turbine trip - high level in moisture separator drain tank.	A	3	Steam & Power (HA)	Turbines	D2.3
3	1/14	16	64		Turbine manually tripped to fix condenser leak.	A	1	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N3.1
4	1/19	109	0	AO 71-02	Reactor shutdown - turbine control valve closed.	A	1	Engineered Safety Features (SF-D)	Valves	D2.1
5	1/25	33	0		Reactor shutdown to repair core spray injection valves.	B	1	Engineered Safety Features (SF-D)	Valves	N1.0
6	1/27	85	0		Traveling screen damaged circulating water pump - damaged shaft.	B	1	Steam & Power (HF)	Pumps	N1.1.4
7	2/12	24	0	RS 71-17	Spurious indication of low reactor water level trip of ECCS.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N1.1.4
8	2/15	3	30		Turbine trip - high moisture separator level.	A	3	Steam & Power (HA)	Turbines	D2.3
9	2/21	21	75		Turbine trip - high moisture separator level.	A	3	Steam & Power (HA)	Steam Turbine	D2.3
10	3/2	65	16		Main steam line safety valve blowing steam.	A	1	Steam & Power (HI)	Valves	D6.1

Table A1.2 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
11	3/12	5	100		Turbine trip - high moisture separator drain tank level.	A	3	Steam & Power (HA)	Turbines	D2.3
12	4/14	3	0		Repair commutator rings on M-G sets.	B	1	Reactor Coolant (CB)	Generators	N1.1.4
13	4/19	6	90		Main steam line low pressure trip sensing line broke.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N2.1
14	4/21	8	45		Turbine trip - high moisture separator drain tank level.	A	3	Steam & Power (HA)	Turbines	D2.3
15	4/22	1	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
16	4/22	-	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
17	4/22	1	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
18	4/22	1	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
19	4/22	1	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
20	5/1	39	60		Repair condensate test line.	A	1	Steam & Power (HH)	Pipes, Fittings	N1.1.4

Table A1.2 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
21	5/12	17	70		Repair air leak in drywell.	A	1	Engineered Safety Features (SA)	Vessels, Pressure	N1.1.4
22	5/25	7	70	AO 71-11	Feedwater control valve closed.	A	3	Reactor Coolant (CH)	Instrumentation & Controls	D1.1
23	5/27	57	80	AO 71-12	Turbine control valves failed shut.	A	3	Steam & Power (HA)	Valves	D2.3
24	5/30	12	20		Steam leak in main steam line.	A	1	Reactor Coolant (CC)	Pipes, Fittings	N3.1
25	6/11	1	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
26	6/11	2	100		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3
27	6/24	2	100	Ltr. 7/21/71	Turbine full load reject due to lightning causing loss of 383 line.	A	3	Steam & Power (HA)	Turbines	D2.2
28	6/25	3	100		Turbine trip due to lightning causing loss of 383 line.	A	1	Steam & Power (HA)	Steam Turbine	D2.2
29	6/26	3	0		Spurious IRM trip.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
30	8/12	4	45		Turbine trip HMSDTL.	A	3	Steam & Power (HA)	Turbines	D2.3

Table A1.2 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
31	8/29	7	45		Traveling screen failure caused loss of circulating water pumps and turbine trip.	A	3	Steam & Power (HF)	Pumps	N1.1
32	8/30	168	0		Main condenser low vacuum trip.	A	3	Steam & Power (HC)	Heat Exchangers (Main Condenser)	D2.5
33	9/23	134	80		850 PSI low pressure trip.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
34	9/29	83	0	AO 71-19	Turbine control valve malfunction.	A	3	Steam & Power (HA)	Valves	D2.3
35	10/3	60	0		Turbine control valve malfunction	A	3	Steam & Power (HA)	Valves	D2.3
36	10/10	248	77	AO 71-20	Turbine control valve malfunction	A	3	Steam & Power (HA)	Valves	D2.3
37	10/22	20	0		Failure of automatic pressure relief valve to seat due to scored pilot valve disc.	A	3	Reactor Coolant (CC)	Valves	N1.1.4
38	10/24	10	0		APR bellows leak.	A	3	Reactor Coolant (CC)	Valves	N1.1.4
39	12/11	4	100		Instrument error on main steam line flow detectors.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
40	12/12	4	100	AO 71-27	Reactor pressure switch inadvertently tripped.	G	3	Reactor Coolant (CC)	Instrumentation & Controls	N6.1

Table A1.2 (Continued)

No.	Date (1971)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
41	12/11	4	100		Inadvertent make-up of reactor pressure switch.	G	3	Reactor Coolant (CC)	Instrumentation & Controls	N6.1
42	12/20	57	100		Faulty isolation condenser return valve.	A	1	Reactor Coolant (CE)	Valves	N1.1.4

Table A1.3 1972 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1972)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	2/4	149	70		Turbine stop valve testing induced pressure oscillations resulting in turbine trip.	A	3	Steam & Power (HA)	Valves	D2.3
2	2/11	43	0		Leaky main steam line gaskets.	A	1	Reactor Coolant (CC)	Pipes, Fittings	N3.1
3	2/14	129	30		Improper response from main steam line venturi differential pressure cells.	A	1	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
4	2/23	168	100	AO 72-08	Degraded main steam line venturi.	A	1	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
5	3/9	62	20		Faulty operation of thrust bearing wear detector induced turbine trip.	A	3	Steam & Power (HA)	Turbines	D2.3
6	3/12	2	30		Void collapse from cold feedwater increase in flow.	A	3	Reactor Coolant (CH)	Pumps	D1.2
7	8/18	5	100		Testing of thrust bearing wear detector tripped turbine.	A	3	Steam & Power (HA)	Instrumentation & Controls	D2.3
8	8/29	27	100		Drywell floor drain sump leakage.	A	1	Engineered Safety Features (SA)	Vessels, Pressure	N1.1.4

Table A1.4 1973 Forced Shutdown and Power Reduction for Millstone 1

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D) NSIC(N) Event Category
1	3/6	53	0		Condensate booster pump not started in time - low water level.	G	3	Reactor Coolant (CH)	Pumps	D2.7
2	3/14	83	80	AO 73-02	Blown fuse on CRD scram solenoid scrammed Group II control rods.	A	3	Reactor (RB)	Circut Closers/ Interrupters	N1.1.4
3	7/30	12	60		Reactor vessel water level transmitter failure.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N2.1
4	8/10	14	76		Reactor vessel water level transmitter level malfunction.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N2.1
5	8/10	4	0		High reactor water level due to starting feedwater pump.	G	3	Reactor Coolant (CH)	Pumps	D1.2
6	8/13	26	76		Fault in mode switch caused a scram.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N2.1
7	9/21	11	50		Fault in EPR controls opened turbine bypasss valves dropping reactor pressure.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	D1.3
8	12/7	5	80		Person bumped level instrument rack.	G	3	Reactor Coolant (CB)	Instrumentation & Controls	N6.3
9	3/11	31	40		Repaired main steam isolation position indication switch.	A	1	Reactor Coolant (CD)	Valves	N2.4
10	3/13	6	75		Low lube-oil pressure alarm on recirc. pump motor.	A	1	Reactor Coolant (CA)	Motors	N1.1.4

Table A1.4 (Continued)

No.	Date (1973)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
11	3/19	40	58		Low lube oil press. alarm reactor recirc. pump.	A	1	Reactor Coolant (CA)	Pumps	N1.1.4
12	4/18	2152	18		Replaced feedwater sparger.	A	1	Reactor Coolant (CH)	Pipes, Fittings	N1.1.4
13	7/14	64	0		Leak on vent line for recirculation pump discharge.	A	1	Reactor Coolant (CA)	Pipes, Fittings	N1.1.4
14	7/16	236	0		Examine for inverted control rod internals.	D	1	Reactor (RB)	Control Rods	N8.3
15	9/19	36	0		Leaking instrument tap in feedwater line.	A	1	Reactor Coolant (CH)	Pipes, Fittings	N1.1.4
16	9/20	25	0		Leaking automatic pressure relief valve.	A	1	Reactor Coolant (CC)	Valves	N1.1.4
17	10/6	16	67		Recirc pump motor failed.	A	1	Reactor Coolant (CA)	Motors	N1.1.4
18	10/14	20	68		Tested recirc. pump motor.	A	1	Reactor Coolant (CA)	Motors	N1.1.4
19	10/28	42	67		Opened and tested recirc. loop cross-tie valves.	A	1	Reactor Coolant (CA)	Valves	N2.4
20	12/30	16	0	AO 73-42	Isolation condenser flange leak.	A	1	Reactor Coolant (CE)	Pipes, Fittings	N1.1.4

Table A1.5 1974 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	3/2	4	50		Power reduction - Suspected leak in main condenser.	A	5	Steam & Power (HC)	Heat Exchanger (Main Condenser)	N1.1.4
2	3/3	7	50		Power reduction - Leak in main condenser.	A	5	Steam & Power (HC)	Heat Exchanger (Main Condenser)	N1.1.4
3	3/6	13	50	AO 74-01	Excessive drywell leakage from stem packing of reactor recirculation equalizer valve.	A	1	Engineered Safety Features (SA)	Valves	N10
4	6/11	7	65		Recirc. pump speed control fault.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N1.1.4
5	11/3	15	35		Turbine trip caused by maintenance on feedwater transmitter.	A	3	Steam & Power (HA)	Instrumentation & Controls	D2.3
6	11/4	9	35	AO 74-09	MSIV malfunction due to moisture in the slide valve that controls valve action.	A	3	Reactor Coolant (CD)	Valves	D2.4
7	11/5	5	40		APRM high flux due to pressure oscillations.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
8	11/15	8	0	AO 74-10	Power reduction - MSIV failed to close.	A	5	Reactor Coolant (CC)	Valves	N1.1.4
9	11/18	15	0		Power reduction - Main generator exciter ground fault.	A	5	Electric Power (EB)	Generators	N1.1.4

Table A1.5 (Continued)

No.	Date (1974)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10	12/16	8	97		Broken stem - feedwater control valve - prevented flow of feedwater.	A	3	Reactor Coolant (CH)	Valves	D2.7
11	12/27	34	95		Repair main feedwater control valve.	A	1	Reactor Coolant (CH)	Valves	N1.1.4
12	12/27	1	15		Power reduction - turbine trip due to high level in moisture separator.	A	5	Steam & Power (HA)	Turbine	D2.3
13	12/29	2	10		Power reduction - turbine trip due to high level in moisture separator.	A	5	Steam & Power (HA)	Turbine	D2.3
14	12/29	3	10		Power reduction - turbine trip due to high level in moisture separator.	A	5	Steam & Power (HA)	Turbine	D2.3

Table A1.6 1975 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1975)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	2/15	9	20		Power reduction - drywell entry made to perform maintenance on TIP index.	A	5	Reactor (RC)	Instrumentation & Controls	N2.1
2	3/11	87	60		Blown valve stuffing box - LPCI system.	A	1	Engineered Safety Features (SF-B)	Valves	N1.1.4
3	5/20	55	100	AO 75-09	Pressure relief valve failed to seat.	A	2	Reactor Coolant (CC)	Valve	N1.1.4
4	6/20	35	15		Service water pump repairs.	A	1	Auxiliary Water (WA)	Pumps	N1.1.4
5	8/13	16	80		Power reduction - arcing on B-phase disconnect.	A	5	Electric Power (EB)	Circuit Closers/ Interrupters	N1.1.4
6	8/18	5	96		Power reduction - APRs failed to meet Tech Specs.	B	5	Reactor Coolant (CC)	Valves	N1.1.4
7	8/30	8	0		Pressure regulator transient caused APRM scram due to plugged moog valve filter.	H	3	Reactor Coolant (CC)	Filters	N1.1.4
8	9/12	451	94		Transformer insulation breakdown.	B	1	Electric Power (EB)	Transformer	N1.1.4
9	10/25	15	2		Installing insulating bolts on main transformer.	H	1	Electric Power (EB)	Transformer	N1.1.4
10	10/27	19	60		Maintenance on transversing incore probe system.	A	1	Reactor (RC)	Instrumentation & Controls	N1.1.4

Table A1.6 (Continued)

No.	Date (1975)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
11	11/13	223	90		Crack in jet pump break detection sensing line.	A&B	1	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
12	11/23	9	0		Oscillations in pressure regulator due to dirt in sensing lines.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
13	11/26	8	60		Pressure spike occurred while switching to mech. pressure regulator.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	N1.1.4
14	12/11	66	90		Installed missing part on main transformer.	A&B	1	Electric Power (EB)	Transformer	N5.1

Table A1.7 1976 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1976)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	2/12	42	100		Arcing across high voltage bushing on main transformer. Tripped generator.	A	3	Electric Power (EB)	Transformers	N1.1.4
2	3/8	85	100	RO 76-10	Inoperability of gas turbine generator due to governor out of adjustment.	A&B	1	Electric Power (EF)	Turbines	N1.1.4
3	3/15	132	20		Inoperability of gas turbine. Replaced electronic governor.	A&B	1	Electric Power (EF)	Turbines	N1.1.4
4	7/16	64	90		Repaired motor operator of isolation condenser isolation valve.	A	1	Reactor Coolant (CE)	Valve Operators	N1.1.4
5	8/10	105	95		High winds deposited salt on main transformer insulators. Arcing.	H	3	Electric Power (EB)	Transformers	N9.2
6	8/10	100	95	RO 76-29	Problems with speed control of gas turbine generator. Outage extension.	A	N/A	Electric Power (EE)	Turbines	N1.1.4
7	8/22	0	65		Power reduction. Adjust control rod pattern.	H	5	Reactor (RB)	Control Rods	N1.1
8	12/1	45	100		Problems with main turbine generator pressure regulator causing it to open.	A	1	Steam & Power (HA)	Instrumentation & Controls	N1.1.4
9	12/17	51	100	RO 76-42	Malfunction of isolation condenser isolation valve, cleanup isolation valve.	A	1	Reactor Coolant (CE)	Valve Operators	N1.1.4

Table A1.8 1977 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1977)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	1/3	49	100		Malfunction of main generator electric pressure regulator due to plugged line.	A	3	Steam & Power (HB)	Instrumentation & Controls	N2.1
2	1/26	13	100	RO 77-05	Increasing coolant conductivity due to demineralizer malfunction.	A	2	Reactor Coolant (CG)	Demineralizers	N1.1.4
3	3/6	36	100		Repair of small steam leak on main line drain line to main condenser.	A	1	Steam & Power (HB)	Pipes, Fittings	N1.1.4
4	4/7	9	100		While performing reactor water level surveillance, an inadvertent reactor scram occurred.	A	3	Instrumentation & Controls (IA)	Valves	N2.4
5	4/23	0	100		Power reduction. Repair steam leak on extraction non-return valve.	A	5	Steam & Power (HA)	Valves	N1.1.4
6	5/14	11	100		Steam leak on an extraction non-return valve.	A	3	Steam & Power (HA)	Valves	N1.1.4
7	6/13	8	0		Faulty test solenoid prevented MS valve from returning to open position.	A	3	Steam & Power (HB)	Instrumentation & Controls	N2.1
8	6/14	132	0		Mechanical pressure regulator swing tripped turbine.	A	2	Steam & Power (HB)	Circuit Closers/ Interrupters	N2.4
9	6/19	6	100		Mechanical pressure regulator did not take control - bypass valves failed open.	A	3	Steam & Power (HB)	Circuit Closers/ Interrupters	N2.4

Table A1.8 (Continued)

No.	Date (1977)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10	7/12	10	100		Bent actuator on main steam isolation valve allowed valve to close.	A	3	Reactor Coolant (CD)	Circuit Closers/ Interrupters	D2.4
11	7/22	37	100		False signal tripped breaker on lube oil pump for recirculating MG set.	A	3	Reactor Coolant (CB)	Instrumentation & Controls	N2.4
12	8/6	37	100	RO 77-24	Loss of plant air due to loss of cooling water to air compressors.	A	3	Auxiliary Process (PA)	Blowers	N1.1.4
13	8/27	0	100		Power reduction. Plug tubes in main condensers.	B	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
14	9/21	0	90		Power reduction. Condenser tube maintenance.	B	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
15	11/22	66	100		Leak in feedwater heater.	A&B	1	Reactor Coolant (CH)	Heat Exchangers	N1.1.4
16	11/29	55	50		Automatic pressure relief valve lifted prematurely.	A&B	2	Reactor Coolant (CC)	Valves	D6.1
17	12/13	269	80	RO 77-40	Manual scram in response to a second hydrogen explosion in offgas stack.	A	2	Radioactive Waste Management (MB)	Other	N1.1.4

Table A1.9 1978 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1978)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	1/31	14	90		Steam leak on 2 inch steam line.	A	1	Reactor Coolant (CC)	Pipes, Fittings	N1.1.4
2	5/19	22	100		Malfunction of level control system for moisture separator tripped turbine.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	D2.3
3	5/29	16	100		Broken air supply tube to moisture separator level controller tripped turbine.	A	3	Steam & Power (HA)	Pipes, Fittings	D2.3
4	7/14	100	100		Replaced containment isolation valve cable splices with those that are environmentally qualified.	B	1	Electric Power (ED)	Electrical Conductors	N10
5	7/20	1	100		Malfunction of moisture separator drain tank level controllers tripped turbine.	A	4	Steam & Power (HB)	Instrumentation & Controls	D2.3
6	12/12	44	100		Main steam line flow instrumentation check out.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.4
7	6/10	0	100		Power reduction. Plug main condenser tubes.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
8	7/3	0	90		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4

Table A1.9 (Continued)

No.	Date (1978)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
9	7/25	0	80		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
10	7/26	0	80		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
11	7/27	0	80		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
12	7/29	0	97		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
13	8/18	0	95		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
14	8/28	0	40		Reduced power to plug main condenser tubing.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
15	9/4	0	70		Reduced power for main condenser maintenance.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
16	12/25	0	75		Reduced power for main condenser maintenance.	A	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4

Table A1.10 1979 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	1/6	269	100	LER 79-01	Stress corrosion cracking of clean-up return line.	A	1	Reactor Coolant (CG)	Pipes, Fittings	N1.1.4
2	1/19	30	70		Change automatic pressure relief valve topworks.	A	1	Engineered Safety Features (SF)	Valve Operators	N1.1.4
3	1/22	0	97		Reduced power for main condenser maintenance.	B	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
4	2/26	33	100	LER 79-05	Safety relief valve lifted prematurely and failed to reseat.	A	2	Reactor Coolant (CC)	Valves	D6.1
5	3/10	0	97		Reduced power for main condenser maintenance.	B	5	Steam & Power (HC)	Heat Exchangers (Main Condenser)	N1.1.4
6	3/17	10	100		MSIV position indicating problems.	A	9	Reactor Coolant (CD)	Instrumentation & Controls	N2.4
7	6/28	0	15		Turbine trip due to feed-water regulating valve lock-up.	A	3	Reactor Coolant (CH)	Valves	D2.3
8	7/2	30	90		Loss of both plant air compressors.	A	3	Auxiliary Process (PA)	Blowers (Compressors)	N1.1.4
9	8/15	0	70		Reduced power for main condenser maintenance.	B	5	Steam & Power (HC)	Condenser	N1.1.4

Table A1.10 (Continued)

No.	Date (1979)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
10	12/19	52	100		Main generator loss of excitation.	A	3	Steam & Power (HA)	Generators (Main Generator Exciter)	D2.3

Table A1.11 1980 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1980)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	1/5	648	100-40		Reduced power to 40% due to isolation condenser out of service.	A	5	Reactor Coolant (CE)	Heat Exchangers	N1.1.3
2	6/25	13	20		Electric pressure regulator malfunction induced APRM scram.	A	3	Reactor Coolant (CC)	Instrumentation & Controls	D2.1

Table A1.12 1981 Forced Shutdowns and Power Reductions for Millstone 1

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
1	4/19	3	0		Low power ascension turbine trip on moisture separator high level. No change on reactor power.	A	9	Steam & Power (HA)	Turbines	D2.3
2	4/21	1372		LER: 81-004	Manual turbine trip on high vibration. Reactor scram on high main condenser conductivity.	A	2	Steam & Power (HA) (HC)	Turbines Heat Exchangers (Condensers)	D2.3
3	6/15	13	0		Reactor mode switch failure.	A	9	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.0
4	7/6				Power reduction. Process computer failure.	A	5	Instrumentation & Controls (IE)	Instrumentation & Controls	N2.0
5	7/12	26			Feedwater regulation valve closure	A	3	Reactor Coolant (CH)	Valves	D2.7
6	7/18				Power reduction. Condensate booster pump repair and service water cross-over valve repair.	B	5	Auxiliary Water (WA)	Valves	N1.1.4
7	8/8	35			Reactor recirculation pump "A" tripped on generator overload with "B" pump off-line. Unit manually scrammed.	A	2	Reactor Coolant (CB)	Generators	D3.1

Table A1.12 (Continued)

No.	Date (1981)	Duration (Hrs)	Power (%)	Reportable Event	Description	Cause	Shutdown Method	System Involved	Component Involved	DBE(D)/ NSIC(N) Event Category
8	8/10	52		LER: 81-023	Unit scrammed during a high risk surveillance when a scrammed channel was not reset prior to scram testing the other channels.	G	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N6.1
9	9/5	55			Shutdown to rebalance turbine.	B	1	Steam & Power (HA)	Turbines	N1.1.4
10	9/14	42			Spurious ATWS system isolation power surge to ATWS system causing scrar : header to depressurize.	A	3	Instrumentation & Controls (IA)	Instrumentation & Controls	N2.0
11	12/3	0	100-40		Power reduction. Find and repair main condenser leaks.	A	5	Steam & Power (HC)	Condensers	N3.1
12	12/28	43			Condensate pump trip due to a discrepancy between a hotwell level transmitter and actual hotwell level.	A	3	Reactor Coolant (CH)	Instrumentation & Controls	N2.0

Appendix A: Millstone 1

Part 2. Reportable Event Coding Sheets

Table A2.1 Coding Sheet for Reportable Events for Millstone 1 - 1970

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RS-70-4	58005	11/8/70	11/17/70	B	EE	DD,NN	M	C	BK	B	N	Gas turbine generator failed during test due to LTA pressure in lube oil pump.
AO-70-5	60225	12/4/70	12/14/70	B	CE	H,OO	M	C	BJ	B	N	Isolation condenser isolated during tests due to design error (NS 12:3 p 248).
RS-70-6	58011 57474	11/19/70	11/25/70	B	CD	OO(2)	-	C	OJ	G,H	N	Steam isolation valve failure improper maintenance procedure and operator error combined (Reactor Shutdown).
RS-70-06	59927	12/9/70	12/19/70	B	CC	Z	-	B	AH	B	C4	Excessive pipe movement during transient due to design error.
RS-70-06	59927	12/9/70	12/19/70	B	CD	OO(2)	-	B	AL	E	C6	MSIV closed due to missing spring in solenoid valve.
RS-70-06	59927	12/9/70	12/19/70	B	HE	OO	-	B	AC	D	N	Steam bypass valve caused malfunction of pressure control.
AO-70-7	59595	12/23/70	1/2/71	B	RB	J	K	C	AM	B	N	Approved wiring change not tested resulting in loss of full rod control
AO-70-8	59595	12/23/70	1/2/71	B	HC	H,Z	-	C	AO	E	N	Welding error caused decrease in condenser vacuum (Reactor Shutdown)

Table A2.1 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-70-9	59594	12/29/70	1/6/71	B	HE	QQ	-	B	AI	D	N	Main steamline bypass valve failure caused by broken linkage on valve operator (Reactor Shutdown).
AO-70-10	59593	12/31/70	1/8/71	B	EE	T,DD	-	C	HK	E	N	Slow turbine start due to reinstallation error in lube oil pump disc. link.

Table A2.2 Coding Sheet for Reportable Events for Millstone 1 - 1971

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-71-1	62296 63204	1/19/71	2/1/71	B	SF-D SF-B	00	T	C	EI	E	S7	Four simultaneous valve failures render ECCS inoperable. Reactor shut down. Cause-torque switches set too low.
AO-71-2	61450	1/19/71	1/25/71	B	SF-B	00	-	C	AK	D	N	Galled threads on valve cause turbine control valve to close.
RS-71-17	62298	2/12/71	3/9/71	B	SF ,IA	00	I	A	OJ	H	N	Error during maintenance on level indicator. Reactor scram on low level.
AO-71-5	62279	2/21/71	3/3/71	B	EE	S,T,NN	T,P	B	BD	D	N	Gas turbine generator fails to start
AO-71-6	62300	3/25/71	4/2/71	B	CC	00,NN	-	C	BI	B	N	Loss of pressure to valve during test reactor shut-down.
AO 71-7	63140	3/31/71	4/8/71	B	SF-B	X,00	-	C	ED	D	N	Motor failed on LPCI valve due to short in windings.
AO-71-8	63139	4/22/71	4/27/71	B	EE	NN,00	T	A	OK	A,G	N	Gas turbine generator inoperable due to a switch being left in the wrong position.
AO-71-9 AO-71-10	63125	5/1/71 5/2/71	5/12/71	B	CG ,WA EB	D,U X,00	-	B	AU,AT	D	C8	Three simultaneous failures in motor control center due to moisture.
AO-71-11	64435	5/25/71	6/4/71	B	CH	00	K	B	HD	B	N	NS 12:6 (1971) p. 619 feedwater control valve problems.

Table A2.2 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-71-12	64436	5/27/71	6/4/71	B	CJ,EE	OO,NN	T	B	EE,ED	E	C8	NS 12:6 (1971) p. 619 Failure of mechanical and electric valve regulator (Reactor Shutdown also, short circuit in speed switch on gas turbine generator.
-	64810	6/24/71	7/12/71	B	EA	-	P	B	EG,OF	F	N	Offsite relay tripped reactor inadvertently during thunderstorms (Reactor Shutdown).
AO-71-13	65552	8/13/71	8/19/71	B	SA,IA	OO	T	C	AL	E,G	N	Drywell high pressure switch had loose hold down screws.
AO-71-14	66469	8/30/71	9/9/71	B	CD	OO	-	B	AG	D	N	Plunger in air slide valve resisted movement.
-	67211	9/22/71	9/22/71	B	WA,SF	DD	-	C	OA	D	N	Insufficient head service water pumps.
AO-71-15	67459 67460	9/17/71	9/28/71	B	SF-B	X	-	C	AH	B	N	2 motors burned out for same test
AO-71-16	67459	9/18/71	9/28/71	B	SF-B	OO	-	C	AC	D	N	LPCI outboard cont. spray valve fails due to pins in wrong position.
AO-71-17	67461	9/27/71	9/30/71	B	SF,WA	DD	-	C	OA	D	N	Emergency service water pumps provide LTA head.
AO-71-17	68264	9/21/71	9/31/71	B	SF,WA	DD	-	C	OA	B	N	Service water pumps LTA head.
AO-71-18	67993	9/23/71	10/4/71	B	HE	NN,OO	-	B	AB	B	N	Turbine bypass valve fails Brittle fracture of studs on linkage, reactor scrammed.

Table A2.2 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-71-19	67992	9/29/71	10/8/71	B	HE	NN,OO	M	B	-	G	N	Failure of steam turbine bypass valve, reactor shutdown. See NS 13:2 p. 137.
AO-71-20	66996	10/10/71	10/22/71	B	CC,ME	NN,OO	M	B	AP,BL	B	S7	Failure of steam turbine bypass valve reactor blowdown (see NS 13:2 p. 137).
AO-71-21	68303	10/13/71	10/20/71	D	IE	DD	N	B	AA,BL	E	N	Two stack gas sample pumps fail off, third tagged out.
AO-71-22	68304	10/13/71	10/20/71	D	SF	OO	-	C	AP	B	N	Rigid air-lines should have been flexible.
AO-71-23	68305	10/16/71	10/20/71	D	CF	OO	-	C	AP	G	N	Valve actuator failed due to loose parts from vibration.
AO-71-24	68788	11/2/71	11/11/71	B	EE	NN	T	C	AL	E,G	N	Gas turbine generator fails to start due to loose connection.
-	68307	-	11/16/71	B	RB	DD	-	C	AT	E	N	Pump in standby liquid control system leaked.
AO-71-25	68308	11/30/71	12/9/71	B	EE	NN,T	U	C	HB,OJ	H	C8	Cold lube oil caused gas turbine trip off. Op. did not turn on oil htrs.
AO-71-26	69199	12/10/71	12/20/71	B	CE	H	-	C	AN	B	N	Stripped threads on yoke sleeve caused isol. cond. valve to fail closed.
AO-71-27	69318	-	12/27/71	B	TB	-	M,P	B	AL	G	N	Electric pressure regulator fails (Reactor Shutdown).

Table A2.3 Coding Sheet for Reportable Events for Millstone 1 - 1972

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-72-1	-	2/3/72	2/15/72	B	CC,IB	-	M	C	OA	B	N	Main steamline differential pressure sensors do not meet manufacturers specs.
AO-72-2	39368	2/4/72	2/15/72	B	IB	QQ,P	M	B	AQ	G	N	Filter clogged in electric pressure regulator pilot valve (Reactor Shutdown).
AO-72-3	39314	2/4/72	2/15/72	B	EE	NN	-	B	EF	E	N	Gas turbine vibration monitor fails.
AO-72-4	39195	2/8/72	2/29/72	B	CC	QQ	M	C	EI	G	N	Set point drift in pressur relief valve controller.
AO-72-5	39317	2/11/72	2/15/72	B	SF-B	QQ	M	B	EG	D	N	Failure of LPCI low pressure switch.
AO-72-6	39177	2/18/72	2/28/72	D	CC	H	M	C	EH	D	N	Set point drift causes pressure sensors in condenser to trip too high.
AO-72-7	39177	2/19/72	2/28/72	D	CC	-	M	C	EH	D	N	Set point drift in main steamline pressure sensors.
AO-72-8	39218	2/23/72	3/2/72	B	CC	-	M	C	AI	B	N	ΔP sensor failed,reactor shutdown.
AO-72-9	55348	3/3/72	3/13/72	B	SF-B	OO	T	C	-	D	N	Cleanup auxiliary pump bypass valve inoperable.
AO-72-10	55347	3/6/72	3/13/72	B	CE	QQ,DD	T	B	EI	D	N	Loss of monitoring capability of cont. isol. valves.

Table A2.3 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-72-11	55353	3/9/72	3/20/72	B	EE	NN	T	B	EG,ED	G	N	Gas turbine generator fails to start—faulty speed switch.
AO-72-12	70045	3/11/72	4/20/72	B	IA	-	T	B	EH	D	N	Set point drift of level sensors.
AO-72-13	70045	4/12/72	4/20/72	B	IA	-	T	B	EH	D	N	
AO-72-14	70045	4/18/72	4/20/72	B	CC	-	M,T	C	EH	D	N	Set point drift of pressure sensors in main steamline.
AO-72-15	71716	6/8/72	6/8/72 6/19/72	B	CE	QQ,H, OO	-	C	-	G	N	Improper assembly of valve.
AO-72-16	72424	6/24/72	7/5/72	B	IA	-	T	C	EH	D	N	Set point drift of high-flow switch.
AO-72-17	72561	7/13/72	7/14/72	B	IA	-	M	C	EI	D	C8	Three pressure sensors trip above tolerance limit.
-	72562	6-12-72	7-13-72	B	ZZ	KK	-	B	AE	D	N	Pipe hangers shifted.
AO-72-18	72774	7/19/72	7/20/72	B	SF	-	P	C	EI	G	C8	4 of 5 time delay relays do not meet specs.
-	73637	-	8/9/72	B	EE	N	M,T	C	EH	D	N	Set point drift causes DG to fail to start.
AO-72-19	73638	8/10/72	8/11/72	B	RA	-	I	C	EH	D	N	Set point drift of reactor vessel low level switch.
AO-72-20	75492	8/15/72	8/23/72	B	CE	H	T	C	EH	D	N	Isolation condenser flow switches set point drift.

Table A2,3 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-72-21	75398	8/31/72	8/31/72	B	CB	DD,FF	-	B	AW	D	N	Excessive coolant rate leak due to bad pump seals.
AO-72-22	75078 75399 75755 77519	9/1/72	9/11/72	B	HC	H	-	B	AR,AU,OF	B	C4	Main condenser tubes leak salt water into coolant seals.
AO-72-23	75400	9/11/72	9/13/72	C	IA	-	T,I	C	EI	G	N	Low-low water level detector out of calibration.
AO-72-24	75345	9/25/72	9/6/72	B	SC	00	-	C	AO,AV	E	N	Crack in header of atmospheric control.
AO-72-25	75795	10/12/72	10/25/72	C	CE	H	T,M	C	EH	D	N	Isolation condenser pressure switch set point drift on 3/4 sensors.
AO-72-26	75910	-	10/21/78	C	CH	Z	-	C	AV	D	N	2 feedwater sparger leaks.
AO-72-27	75902	-	10/28/72	C	CA	00	-	C	OA	G	N	Penetration leaks and isolation valve leaks during testing.
-	76011	8/25/72	9/23/72	B	EA	LL	-	B	-	D	C5	Plane crashes into power transformer.
-	76071	-	10/13/72	C	CE	H	T	C	EH	D	N	Set point drift of 3 isolation cond. switches.

Table A2.4 Coding Sheet for Reportable Events for Millstone 1 - 1973

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
-	77956	-	1/26/73	B	RB	I,A	-	B	AT,AR	B,G	S7,S2	Accumulators for control rod drive found to be bad, all replaced (see NS 14:4 p. 373).
AO-73-1	80136	3/7/73	3/8/73	B	RB	I	-	C	BI	D	N	Excessive scram time 2/145 C.R.'s.
AO-73-2	79560	3/14/73	3/21/73	B	RB,EE	S,T,H, NN	P	B	EI,ED	G	N	Scram on blown CRD fuse; gas-turbine fails to start.
AO-73-3	80118	3/21/73	3/27/73	B	CH	DD,D	-	B	AB	G	N	Inboard bearing failure.
AO-73-4	80274	4/5/73	4/12/73	B	CE	H,QQ	T	B	BC,HA, OK	G	C8	Isolation condenser isolated on high flow due to incorrect maintenance.
AO-73-5	80275	4/5/73	4/13/73	B	EE	T,NN	-	C	OJ,OA	H	N	Gas turbine generator fails to start after isolation condenser failure. Operator made wrong adjustment during startup.
AO-73-6	80728	4/18/73	5/18/73	D	CF	QQ	-	B	AD,AI,AM	B	N	Valve operator broke on shutdown cooling system isolation valve improper sized motor.
-	80710	-	5/21/73	D	CH	Z	-	C	AV	D	N	Report on spargers crack in feedwater system.
-	84795	7/18/73	7/18/73	C	ZZ	GG	-	C	AT	G	N	Shock suppressors leaked hydraulic fluid, deterioration of seals.

Table A2.4 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
-	82972	-	7/13/73	C	CB	OO	-	B	BA	D	N	Recirc. vent valve line leaks.
AO-73-8	82957	8/2/73	8/2/73	C	SF-B	-	M,T	C	EH	D	N	Set point drift on DP sensors of LPCI.
-	82966	-	8/8/73	C	RB	J	-	C	CA	D	N	Control rod uncoupled.
-	82968	-	8/6/73	C	CH	Z	M	C	AU	D	N	Leak in pressure sensing line.
AO-73-9	83225	8/13/73	8/20/73	C	IA	-	I	B	AM	E	N	Level sensors read wrong due to mismatch in ventilation around sensor
-	84017	-	8/30/73	C	SF-D	DD,QQ	-	C	BA,EC	D	N	Failure of core spray valve to open.
AO-73-10	84491	9/21/73	10/1/73	B	IA	OO	I	B	AT	D	N	Mismatch in level indicators due to valve leak.
AO-73-11	84497	9/22/73	10/1/73	B	CH	D	-	A	BL	G	N	Condensate booster pump bearing over heats-rework bearings.
-	84551	-	11/4/73	B	SH-B	-	T,I	C	-	D	N	Level switch failed to trip.
AO-73-12	88079	12/30/73	1/7/74	B	CE	Q	-	B	AU	D	N	Steam leak in isolation condenser flange (Reactor Shutdown).

Table A2.5 Coding Sheet for Reportable Events for Millstone 1 - 1974

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
-	93695	1/6/74	2/1/74	B	CA	OO	-	B	AB	D	N	Pressure relief valve lifts due to worn preload ass'y.
-	89258	-	3/8/74	B	ZZ	GG,FF	-	B	AT	B	N	Snubbers leak.
AO-74-1	89340	3/6/74	3/15/74	B	CB	BB,OO,FF	-	B	AU	D	N	Drywell leak due to seal packing failure (Reactor Shutdown).
-	89663	-	4/1/74	B	CB	DD,QQ,OO	P	B	BB,OK	G	N	Pump suction valve on recirc. pump fails to close.
AO-74-2	92184	5/17/74	5/28/74	B	CH	DD,D	-	B	AB	B	N	Inboard bearing FWCI condensate pump 2nd failure.
AO-74-4	95140	8/28/74	9/5/74	B	SH-D	FF	-	C	AW	D	N	Tear in seal at Rx bldg-turbine bldg interface.
AO-74-6	95426	9/18/74	9/25/74	C	CB	Z	-	C	AO	B	N	Weld cracks in recirc. loop discharge bypass lines.
AO-74-8	97077	10/31/74	11/6/74	C	WA, SF-B	OO	-	C	BA	B	N	Emergency service water valve fails due to manual overtorqueing.
AO-74-9	97076	11/4/74	11/12/74	B	CD	QQ,P	-	C	HC	G	N	Foreign material in air slide valve disables valve operator (Reactor Shutdown).

Table A2.5 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-74-10	97506	11/15/74	11/18/74	B	CD	QQ,P	-	C	HC	G	N	Air slide valve clogs-second time in one month (Reactor Shutdown).
AO-74-11	98161	12/13/74	12/19/74	B	CG	QQ	-	A	AB,BC	D	N	Misalignment of gear train on valve motor op.
AO-74-12	98582	12/20/74	12/30/74	B	SD	H	I	C	EH	D	N	Set point drift on level sensor in isolation condenser. Set point lock installed.
AO-74-13	98581	12/20/74	12/30/74	B	HC	H	M	C	EH	D	N	Set point drift on condenser vacuum swtiches
AO-74-14	98705	12/23/74	1/2/75	B	SF-B	MM	I	B	HC,BT	G	N	Level sensor tubing blocked. Blowout tube installed.
AO-74-15	98706	12/28/74	1/2/75	B	ZZ	GG	-	C	AT	E	N	2 snubbers had no fluid. Improper installation.

Table A2.6 Coding Sheet for Reportable Events for Millstone 1 - 1975

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
-	99684	-	1/24/75	B	WC	M	-	B	OF	D	C8	Hydrogen explosion in acid day tank due to moisture.
AO-75-2	93569	1/25/75	1/30/75	B	CC	Z	E	B	AD	D	N	Flow indicator reading decrease due to weld crack in sensing tube.
AO-75-4	93515	1/29/75	1/31/75	B	EE	NN,T	P	B	EF	D	N	Spurious operation of relay causes turbine startup sequence to begin.
AO-75-5	101408	3/27/75	4/3/75	B	WF,MA	V	-	B	AW,OD	E	N	Wiring error caused flow of contaminate into boiler system.
AO-75-6	101701	3/30/75	4/8/75	B	MA	-	-	B	OD,OK	A	C3	Inadvertent discharge of radioactive liquid due to procedure error.
AO-75-7	102297	4/18/75	4/24/75	B	EE	T,C	P	B	EB	D	N	Oscillator board trips inverter operation.
AO-75-8	103148	5/20/75	5/29/75	B	EE	NN,T,QQ	T,U	C	EI,BL	G	N	Incorrect valve position plus temp. sensor error cause gas turbine trip.
AO-75-9	104066	5/20/75	7/11/75	B	CC	OO	-	B	BP,BB	D	N	Safety/relief valve fails to reset - no cause found (Reactor Shutdown).
AO-75-10	103074	5/21/75	5/28/75	B	ZZ	GG,FF	-	/	BT	B,E	N	No fluid in two snubbers due to improper assembly.

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-11	103879	6/26/75	7/2/75	B	CC	-	T,M	C	AR,AU	G	N	Moisture from leak causes switch failure.
AO-75-14	105835	7.14/75	7/22/75	B	CE	H	E,T	C	EH	D	N	Set point drift in flow sensors on isolation condenser.
AO-75-15	104868	7/22/75	8/1/75	B	CC	MM	M	B	HD	B	N	Variation in diff. pressure data due to sensing tube failure.
AO-75-16	106457	8/16/75	8/22/75	B	IA	-	M,T	C	EH	D	N	Set point drift on vessel high pressure switch.
AO-75-17	105547	8/18/75	8/26/75	B	CC	QQ	-	C	AQ	G	N	Safety/relief valve bellows integrity could not be verified due to grit in air lines.
AO-75-18	106343	9/8/75	9/15/75	B	IB	BB	M,T	C	EH	D	N	Set point drift of dry-well high pressure switches.
AO-75-19	107502	10/12/75	10/21/75	C	IA	-	U,T	C	EH	D	N	Set point drift on steam tunnel temp. sensors.
AO-75-20	107501	10/13/75	10/22/75	C	IE	-	N,T	C	EH	D	N	Set point drift of ventilation radiation monitor.
AO-75-21	108248	11/13/75	11/25/75	B	CB	Z	-	B	AO,AI,AW	B	N	Instrument pipe weld crack due to fatigue.
AO-75-22	108520	11/24/75	12/3/75	B	HC	-	M,T	C	EH	D	N	Set point drift in condenser low vacuum switch.

Table A2.6 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
AO-75-23	108889	12/9/75	12/18/75	B	IB	BB	M,T	C	EH	D	N	Set point drift of dry-well high pressure switches.
AO-75-24	108888	12/19/75	12/23/75	B	CD	–	P,T	C	BC	G	N	Valve position switch out of position caused MSIV close relay to fail.
AO-75-25	109191	12/17/75	12/23/75	B	IB	–	P	C	EH	D	N	Relay set point drift.
AO-75-26	109454	12/30/75	1/7/76	B	WA	P	–	C	AQ	G,A	N	Grit in strainer caused emergency service water pump trip.
AO-75-27	109459	12/23/75	1/7/76	B	SF-B	–	M,T	C	EH	D	N	Set point drift in LPCI pressure switch.
RO-75-28	110932		12/28/76	B	CG	JJ	–	B	AR	D	N	Hole in cleanup filter sludge tank.

Table A2.7 Coding Sheet for Reportable Events for Millstone 1 -1976

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-2	111648	1/26/76	2/25/76	B	SA	F	-	C	AA	D	N	Vacuum breaker fails due to teflon bushing out of round.
RO-76-3	111658	2/10/76	3/9/76	B	RC	H	M,T	C	EH	D	N	Set point drift on condenser low vacuum switch.
RO-76-4	111647 120080	2/12/76	3/5/76 9/28/76	B	CD	H	-	B	AR	A,B	S7	Isolation condenser tube failure due to corrosion cracking NS 17:4 pp. 494-495.
RO-76-5	112163	2/12/76	3/12/76	D	CH	QQ	M	B	AI	D	N	Feedwater regulation valves lock due to diaphragm failure in regulator.
RO-76-7	112308	2/19/76	3/15/76	B	CC	NN	M,T	C	EH	D	N	Instrument drift caused turbine relays to trip.
RO-76-8	1111911	2/29/76	3/15/76	B	EE	NN,T	-	C	BC	G	N	Gas turbine governor out of adjustment.
RO-76-10	112309	3/8/76	3/22/76	B	EE	NN,T	-	C	BC	G	S7,S1	Gas turbine generator governor out of adjustment, (Reactor Shutdown).
RO-76-11	112162	3/9/76	3/23/76	B	ZZ	GG	-	C	BT,AU	G	N	Shock suppressor low on fluid.
RO-76-12	112310	3/15/76	3/29/76	B	EE	NN,T	-	C	BC	D	N	Gas turbine generator inoperable due to governor failure while isolation condenser unavailable.
RO-76-16	113541	4/22/76	5/4/76	B	CD	OO	-	C	AG	D	N	Primary containment isolation valves fail to close due to internal binding.

Table A2.7 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-17	113540	4/23/76	4/30/76	B	RB	R	-	B	OG	B	C3	Excess stack gas release due to fuel clad perforations.
RO-76-23	114643	5/28/76	6/11/76	B	CD	H	-	B	BU	E	N	Increase in chloride ion concentration in cond. return leg.
RO-76-27	115725	6/23/76	7/9/76	B	IA	-	M,T	B	EH	D	N	Set point drift in pressure switch.
RO-76-28	116269	7/14/76	7/30/76	D	RC	QQ	-	C	CA	E	N	Isolation condenser inboard isolation valve inoperable due to previous fix for leak.
RO-76-29	116780	8/10/76	8/24/76	B	EE	NN,T	-	C	EA,BF	B	S8,S7	Gas turbine generator trips out on incorrect AC feed.
RO-76-30	117678	8/31/76	9/8/76	B	EE	NN,T	-	C	BF	D	N	Gas turbine generator trips on overspeed. Speed switch faulty.
RO-76-31	117679	8/13/76	9/9/76	D	IA	-	L	C	EH	D	N	Set point drift in intermediate range monitors.
RO-76-32	118795	9/25/76	10/8/76	B	SF-B	PP	-	B	AW	G	N	Packing leak in LPCI testable check valve.
RO-76-33	120533	10/28/76	11/23/76	C	RI	R	-	C	AD	D	N	Neutron source rod broken.
RO-76-34	120436	11/12/76	11/24/76	C	RB	I	-	C	OJ,OK	A,H	S8	Inadvertent criticality due to operator error during shutdown margin test.

Table A2.7 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-76-35	120272	11/9/76	12/3/76	C	CC	-	U,T	C	EH	D	N	Set point drift of steam tunnel temp. switch.
RO-76-36	120228	11/22/76	11/27/76	C	SF-D	Z	-	C	AO,AV	B	N	Weld joint leak in head spray system due to stress corrosion.
RO-76-37	120670	12/7/76	12/30/76	B	IA	-	M,T	C	EH	D	N	Set point drift of dry-well pressure switches.
RO-76-38	120669	12/18/76	12/30/76	B	SH-B	-	M,T	C	EH	D	N	Set point drift of containment spray pressure switches.
RO-76-40	121055	12/14/76	1/12/77	B	CC	-	M,T	C	EH	D	N	Set point drift in main steam line flow switch.
RO-76-42	121034	12/17/76	1/14/77	B	CE	QQ	T	C	BB,EI	G	N	Isolation condenser steam supply valve fails to close due to incorrect torque switch setting (Reactor Shutdown).
RO-76-43	121035	12/18/76	1/14/77	B	CE	QQ	T	C	BB,EI	G	N	Isolation condenser condensate return valve torque switch miscalibrated.
RO-76-44	121036	12/18/76	1/14/77	B	CG	QQ,X	-	C	AH,BA,OK	G	N	Procedural error caused overload of motor on valve.

Table A2.8 Coding Sheet for Reportable Events for Millstone 1 - 1977

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-77-2	122206	1/8/77	2/7/77	B	BB	AA,S	N	B	EA	B	C4	Both stack gas monitors inoperable due to blown fuse in power supply
RO-77-3	122174	1/12/77	2/10/77	B	IA	-	M,T	C	EH	D	N	Set point drift in dry-well pressure swtich.
RO-77-4	122136	1/25/77	2/23/77	B	SA	QQ,MM	-	B	AQ,BB	G	N	Drywell vent bypass valve fails to close due to grit in air operator line
RO-77-5	122137	1/26/77	2/24/77	B	CB	M	-	B	BU	G	N	High coolant conductivity due to improper rinsing of resin in demineralizer (Reactor Shutdown).
RO-77-6	122138	1/28/77	2/28/77	B	CE	H	-	A	OF	I	N	Impending storm conditions halted maintenance of isolation condenser.
RO-77-7	122429	2/1/77	3/1/77	B	EE	Y,T,N	-	C	OA,AT,AV	D	N	Diesel generator inoperable due to fuel oil leak-cracked nipple.
RO-77-8	122139	2/1/77	2/28/77	B	CE	H	-	A	BU	B	N	High chloride ion concentration in isolation condenser.
RO-77-9	123022	2/11/77	3/11/77	B	IA	-	I,T	C	EH	D	N	Set point drift in reactor water level switch.
RO-77-10	123023	2/14/77	3/11/77	B	IA	BB	M,T	C	EH	D	N	Set point drift in dry-well pressure swtich.
RO-77-11	129462	2/14/77	3/14/77	B	CC	-	M,T	C	EH	D	N	Set point drift in main steam line pressure switch.

Table A2.8 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-77-12	123024	2/15/77	3/14/77	B	HC	H	M,T	C	EH	D	N	Set point drift in condenser vacuum switch
RO-77-13	124872	3/18/77	3/30/77	B	SF-B	-	-	C	BV	A	N	Low concentration in standby liquid control system due to low temp in storage tank
RO-77-14	125214	5/3/77	5/17/77	B	IA	-	M,T	C	EH	D	N	Set point drift in reactor low pressure pump start permissive switch
RO-77-15	125177	5/14/77	6/7/77	B	SH-D	S	-	B	EH,OA	D	N	Standby gas treatment system circuit blown fuse.
RO-77-16	125594	6/14/77	6/27/77	B	CB	Z	-	A	AW	D	N	Leak in recirc loop drain - cause unknown
RO-77-17	130698	6/17/77	6/17/77	B	CC	OO	-	C	AY	D	N	Safety/relief valve opens - no cause known
RO-77-18	126008	6/18/77	7/1/77	B	CC	OO,P	-	B	AT	D	N	Safety/relief valve seat leakage due to filter failure
RO-77-19	126489	6/15/77	7/15/77	B	CE	H	M,T	C	EH	D	N	Set point drift in isolation condenser actuation press. switch
RO-77-20	143504	7/14/77	7/26/77	B	BB	DD	-	C	AC	D	N	Cooling fan deterioration causes loss of stack sampler
RO-77-21	143468	7/13/77	8/5/77	B	CH	OO	-	B	AC	D	N	Degradation of valve diaphragm causes loss of full FWCI Capability

Table A2.8 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER 77-22	143507	7/21/77	8/19/77	B	CC	OO,G	A	B	ED	D	N	Safety/relief valve bellows alarm received due to wiring short circuit.
RO-77-23	143469	8/5/77	8/31/77	B	IC	F	–	B	AB	B	N	Three vacuum breakers fail to close due to friction
RO-77-24	143470	8/6/77	8/30/77	B	IX	OO	–	B	AC	B	N	Reactor scram on loss of instrument air. Gasket failure (Reactor shutdown)
LER 77-25	143509	8/7/77	8/30/77	B	CC	OO	K,T	C	AC	D	N	Pressure switch on bellows monitor fails
LER 77-27	143511	9/9/77	10/7/77	B	EE	NN	–	C	EG	D	N	Spurious noise halts gas turbine startup tests.
LER 77-28	143512	9/12/77	10/11/77	B	SD	H	M,T	B	EH	D	N	Set point drift in isolation condenser pressure switches
RO-77-29	143561	9/27/77	10/14/77	B	EE	N,MM	–	B	AT	D	N	Diesel generator inoperable due to fuel oil leak
RO-77-30	143471	10/12/77	11/2/77	B	SH-D	FF	–	C	AV	D	N	Standby gas treatment system inoperable due to leak in seal
LER 77-32	143555	11/01/77	11/15/77	B	BB	DD	–	B	AA	D	N	Stack sample pump trips due to normal pump
LER 77-33	143543	11/18/77	12/2/77	B	RX,CC	OO	M	B	BP	D	C6	Reactor cooldown rate exceeded limit when a safety/relief valve lifted at a low pressure.
LER 77-34	143546	10/28/77	11/23/77	B	CC	OO	A	B	ED	E	N	Bellows leakage alarm sounds due to wiring short circuit

Table A2.8 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-77-35	143472	10/31/77	11/29/77	B	CE	QQ	-	B	OA	D	N	Isolation condenser steam supply valve inoperable due to unknown cause
LER 77-36	143547	11/7/77	12/2/77	B	IA	-	I,T	C	AG,AQ	G	N	Low-low level switch fails to trip due to grit.
RO 77-37	144121	11/30/77	3/3/78	C	ZZ	GG	-	C	OA	E	N	Two snubbers declared inoperable
RO 77-38	143485	11/10/77	12/9/77	B	SF-B	QQ	-	C	ED	G	C8	Maintenance foreman inadvertently short circuits valve operator on LPCI valve
RO 77-39	144187	12/10/77	12/12/77	B	EE	N,NN	-	C	OA	D	S1,S7	Diesel generator declared inoperable, gas turbine unavailable.
RO 77-40	144186	12/13/77	12/14/77	B	SC	-	-	-	-	G	S9	Two hydrogen explosions in off-gas system reactor shutdown
RO 77-43	133684	12/19/77	1/18/78	D	BB	KK	N	A	BC	H	N	Stack gas sampler and structure damaged due to hydrogen explosion.

Table A2.9 Coding Sheet for Reportable Events for Millstone 1 - 1978

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-1	134979	1/16/78	2/14/78	B	CC	-	M,T	C	EH	D	N	Setpoint drift in main steam line low pressure switches
RO-78-2	134961	1/17/78	2/14/78	B	SH-D	P	-	C	AA	D	N	Pressure drop limit exceeded due to normal wear of filter
RO-78-3	136464	2/14/78	2/28/78	B	HA	QQ	P	C	EH	D	N	Set Point drift in turbine control time delay relay
RO-78-4	142572	3/10/78	3/24/78	C	IB	OO	-	B	BB	D	N	Safety/relief valve fails to reseat. Cause unknown
RO-78-5	137251	3/19/78	4/3/78	C	CB	OO,Z	-	A	AO,AI,AT	B	N	Fatigue caused weld leak in recirc. discharge valve vent line
RO-78-6	137252	3/20/78	4/3/78	C	CD	OO	-	A	AT	D	N	Containment isolation valve excess leakage
RO-78-7	137504	3/11/78	4/10/78	C	CE	H,Z		A	BS	G	N	Pipe movement in isol. condenser due to water in steam lines
RO-78-8	137504	4/17/78	4/20/78	B	SF-B SF-D	KK	-	B	AH	B	N	Degradation of core spray and LPCI piping-support structure due to poor design
RO-78-9	138250	4/3/78	4/25/78	B	CC	-	M,T	C	EH	D	N	Set point drift in steam tunnel temp. switches

Table A2.9 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-10	138838	4/24/78	5/23/78	B	RB	J,OO	-	C	BI	E	N	Scram time too slow for control rods. Due to tight packing on valve
RO-78-11	139384	5/8/78	6/6/78	B	IA	-	M,T	C	EH	D	N	Set point drift in containment pressure switch
RO-78-12	139640	5/19/78	6/16/78	D	EE	NN,T	-	C	BI,EI	D	N	Gas turbine fails to complete startup sequence due to incorrect governor setting
RO-78-13	139817	5/29/78	6/20/78	D	CE	H	-	B	BL	G	N	Steam trap blow by causes isolation condenser to be removed from system.
RO-78-14	139876	6/13/78	7/12/78	B	EE	NN,T	T	B	BW	D	N	Gas turbine trips out due to overspeed switch failure
RO-78-16	140261	7/5/78	8/4/78	B	HC	H	M,T	B	EH	D	N	Set point drift in condenser low vacuum switch
LER 78-16	140386	7/25/78	8/9/78	B	SH-A	-	A	B	OK	G	C8	Procedural error allowed containment to be purged without high radiation monitor.
RO-78-17	140032	7/10/78	8/4/78	B	FB	-	N	C	EI	G	N	Calibration error in spent fuel storage air monitors.
RO-78-18	141762	9/5/78	10/4/78	B	IA	-	I	C	AK	G	N	Lack of lubrication causes low low water level sensors to fail

Table A2.9 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
RO-78-19	141763	9/12/78	10/10/78	B	IA, HA	NN	P	C	EH	D	N	Set point drift in turbine control time delay relay
RO-78-20	148110	10/10/78	10/10/78	B	WC	M	-	B	OA	D	N	Chlorine capacity of demineralizer less than tech. specs.
RO-78-21	141139	9/14/78	10/12/78	B	EE	NN	T	C	BF	D	N	Faulty speed switch trips gas turbine
RO-78-22	141149	9/14/78	10/13/78	B	ZZ	QQ,BB	-	B	AQ	G	N	Drywell vent bypass valve fails to close due to dirt in air operator.
RO-78-23	141726	10/11/78	11/6/78	B	IA	BB	M,T	C	EH,AK	D	N	Setpoint drift in drywell high pressure switch
RO-78-24	141729	10/19/78	11/16/78	B	CE	QQ,H	T	B	BF	G	N	Spurious opening of isolation condenser isolation valve due to set point drift
RO-78-26	142286	11/6/78	11/30/78	B	IA	BB	M,T	C	EH	D	N	Set point drift in drywell high pressure switch
RO-78-27	142285	11/6/78	12/1/78	B	IA	-	I	C	EH	D	N	Set point drift in reactor low level switch
RO-78-29	142849	11/22/78	12/22/78	B	EE	NN,T	G	C	OA,AA	G	N	Gas turbine inoperable when maint. crew had to repair damaged indicator light socket
LER-78-30	146505	12/18/78	1/17/79	B	ZZ	BB	-	-	OK,BU	A	N	Excess oxygen in drywell due to procedural error

Table A2.10 Coding Sheet for Reportable Events for Millstone 1 - 1979

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-1	146724	1/6/79	1/18/79	D	CG	Z	-	A	AO,AV	D	N	Stress corrosion cracking of cleanup system return line weld (reactor shutdown)
LER-79-2	146643	1/7/79	2/6/79	D	SH-D	-	P	B	BC,BD	E	N	SBGT system "A" fails to start due to misalignment of startup relay
LER-79-3	146644	1/8/79	2/7/79	D	CC,ID	-	M,T	C	EH	D	N	Setpoint drift in main steam line pressure switch
LER-79-4	147428	1/25/79	2/23/79	B	RB	I	-	C	AG	D	N	Control rod sticks. Cause unknown.
LER-79-5	147414	2/26/79	2/26/79	B	CC	OO	-	D	AB	D	C8	Pressure relief valve lifts prematurely and fails to seat due to steam cutting of disc (reactor shutdown)
LER-79-6	147295	2/1/79	3/2/79	B	RB	I	-	B	OJ	H	C8	Two control rods inoperable due to operator error
LER-79-7	147413	2/14/79	3/9/79	B	EE	NN,T	T	C	BD	D	N	Gas turbine generator fails to start due to faulty speed switch.
LER-79-8	147415	2/14/79	3/14/79	B	CE,ID	QQ	K	A	AD	D	N	RCIC valve loses position indication due to failure of valve operator casing

Table A2.10 Coding Sheet for Reportable Events for Millstone 1 - 1979

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-1	146724	1/6/79	1/18/79	D	CG	Z	-	A	AO,AV	D	N	Stress corrosion cracking of cleanup system return line weld (reactor shutdown)
LER-79-2	146643	1/7/79	2/6/79	D	SH-D	-	P	B	BC,BD	E	N	SBGT system "A" fails to start due to misalignment of startup relay
LER-79-3	146644	1/8/79	2/7/79	D	CC,ID	-	M,T	C	EH	D	N	Setpoint drift in main steam line pressure switch
LER-79-4	147428	1/25/79	2/23/79	B	RB	I	-	C	AG	D	N	Control rod sticks. Cause unknown.
LER-79-5	147414	2/26/79	2/26/79	B	CC	OO	-	D	AB	D	C8	Pressure relief valve lifts prematurely and fails to seat due to steam cutting of disc (reactor shutdown)
LER-79-6	147295	2/1/79	3/2/79	B	RB	I	-	B	OJ	H	C8	Two control rods inoperable due to operator error
LER-79-7	147413	2/14/79	3/9/79	B	EE	NN,T	T	C	BD	D	N	Gas turbine generator fails to start due to faulty speed switch.
LER-79-8	147415	2/14/79	3/14/79	B	CE,ID	QQ	K	A	AD	D	N	RCIC valve loses position indication due to failure of valve operator casing

Table A2.10 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-9	148229	2/22/79	3/22/79	D	CC	OO	G	C	OA,AV	D	N	Safety/Relief valve bellows monitor inoper, due to crack in air tube fitting
LER-79-10	149268	4/3/79	4/18/79	B	RC	-	-	B	OJ	H	N	Core thermal power exceeds tech specs due to operator error
LER-79-11	149267	3/17/79	4/17/79	B	CD	OO	P	C	BB,BC	D	N	MSIV relay fails to deenergize due to maladjustment of relay limit switch (reactor shutdown)
RO-79-11	152303	5/14/79	5/18/79	C	SA	Z	-	A	AA	D	N	Leak rate of penetrations exceeded
LER-79-12	149544	4/23/79	5/21/79	B	BA	-	N	C	EH	D	N	Set point drift in reactor building radiation monitor
LER-79-15	150110	5/28/79	6/22/79	C	RB	J	K	C	AH	D	N	Control rod out block function fails due to worn limit switch
LER-79-16	150109	5/30/79	6/29/79	C	IA	-	M,T	C	EH	D	N	Set point drift in reactor low pressure switch.
LER-79-17	150108	6/2/79	6/28/79	C	IA	-	U,T	C	EH	D	N	Set point drift in steam tunnel temperature switch

Table A2.10 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-18	150748	7/13/79	7/26/79	B	SF-B	-	-	A	OK,BU	A	C8	Concentration in Standby liquid control system LTA due to procedural error
LER-79-19	150782	6/28/79	8/3/79	D	CE	OO	-	C	AA,AU	D	N	Containment isolation valve leakage due to normal wear
-	150990	2/16/79	3/19/79	B	IA	-	G	B	BU,OK	A	N	Abnormal oxygen levels in containment due to cancellation of shutdown
LER-79-20	151245	7/11/79	8/9/79	B	IA	-	I,T	C	EH	D	N	Set point drift in reactor low-low level switch
LER-79-21	151244	7/12/79	8/10/79	B	IA	-	I,T	C	AQ	G	N	Low low water level switch fails to trip due to grit on shft assembly
LER-79-22	151211	7/23/79	8/22/79	B	SC	QQ	-	B	BB	D	N	Containment vent bypass valve fails to close - cause unknown
LER-79-23	151207	8/8/79	8/24/79	B	SC	QQ	-	B	BB	D	N	Same as above
LER-79-24	151425	7/31/79	8/30/79	B	BA	-	N	C	EH	D	N	Set point drift in refueling floor radiation monitor
LER-79-25	151913	9/13/79	9/25/79	B	RB	-	-	B	OK	B	N	Total peaking factor in error due to design oversight

Table A2.10 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-26	151912	9/14/79	9/27/79	B	SF	-	-	B	OK	B	S7	Potential existed for loss of power to ECCS to go undetected-design erro
LER-79-27	151758	8/27/79	9/24/79	B	AB	-	-	B	OC	G	N	System not tested acc'd to schedule
LER-79-28	151911	8/28/79	9/25/79	B	CC	QQ	-	C	BB,AR	D	N	Pressure suppression chamber vent bypass valve fails to close due to rust buildup
LER-79-29	151930	9/4/79	10/4/79	B	CE	QQ,H	T	C	BB	D	N	Isolation condenser isolation valve fails to close due to faulty microswitch
LER-79-30	152940	10/9/79	11/8/79	B	EE	KK,N	-	B	AL	E	N	Service water system pipes to DG not restrained due to installation error
LER-79-31	153647	10/16/79	11/15/79	B	SF-C	KK	-	B	OA,AL	E	N	Feedwater coolant injection system declared inoperable due to missing support structure
LER-79-32	153362	11/6/79	12/3/79	B	IA	-	M,T	C	EH	D	N	Set point drift in drywell pressure switches
LER-79-33	153360	11/13/79	12/4/79	B	IA,CC	-	M,T	C	EH	D	N	Set point drift in main steam line delta P switch
LER-79-34	153749	11/15/79	12/14/79	B	SF-B	QQ,X	-	C	OA,ED	D	N	LPCI Valve inoperable due to electrical fault in motor controller

Table A2.10 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-79-35	153906	12/4/79	12/20/79	B	IA	-	M,T	C	EH	D	N	Set point drift in main steam low pressure switch
RO-79-36	153942	12/19/79	1/18/80	D	CE	Z,H	-	B	HH	D	N	Water hammer in isolation condenser piping

Table A2.11 Coding Sheet for Reportable Events for Millstone 1 - 1980

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-80-01	154444	1/3/80	2/1/80	B	CB	DD	-	B	BW	D	N	Pump speed mismatch during recirc pump runback
LER-80-001	155196	1/31/80	2/14/80	B	-	-	-	-	-	B	N	MAPLHGR wrong
LER-80-3	154614	1/4/80	2/4/80	B	CB	KK	-	B	AH	B	N	Structural Deficiency in isolation cond. system supply line (Reactor shutdown)
LER-80-4	155195	1/21/80	2/14/80	B	IA,CC	-	E,T	C	EH	D	N	Set point drift in main steam line high flow switch
LER-80-5	156005	2/20/80	3/17/80	B	SF-D	KK	-	C	AC,HH	D	N	Core spray supports damaged by water hammer.
LER-80-6	156157	4/7/80	4/21/80	B	IA	-	M,T	C	OK	E	N	Pressure sensor isolated due to installation error
LER-80-8	158283	6/5/80	7/2/80	B	SA	-	M,T	C	EH	D	N	Set point drift in two reactor pressure switches
LER-80-9	158276	6/5/80	7/2/80	B	IA	-	M,T	C	EH	D	N	Set point drift in reactor protection low pressure switches
LER-80-10	159128	6/13/80	7/11/80	B	RA	KK	-	B	AC	E	N	Bolts on penetration base plate faulty due to installation error
LER-80-11	160233	8/3/80	8/15/80	B	BB	OO	N	C	BC,OA	G	N	Off gas radiation monitoring system inoperable due to valve misalignment

Table A2.11 (continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-80-12	159289	7/25/80	8/22/80	B	IC	-	N	C	EI	G	N	APRM reads low due to calibration error
LER-80-13	160459	9/8/80	10/3/80	B	IA	-	M,T	C	EH	D	N	Set point drift in high pressure switch
LER-80-14	160060	10/05/80	10/16/80	C	CD	OO	-	C	-	D	N	Leak rate test failure of two MSIV's
LER-80-15	160923	10/7/80	10/24/80	C	IA	-	I,T	C	AQ	G	N	Set point drift in low water level scram switch - grit.
LER-80-16	161870	10/23/80	11/6/80	C	CB	DD,KK	-	C	AH	C	N	Cracks found in jet pump support beams
LER-80-18	161470	11/5/80	11/19/80	C	CC	Z	-	C	AO	D	N	Weld failure in two main steam lines
LER-80-19	161471	11/6/80	11/20/80	C	CC	Y	-	C	AO	D	N	Condenser Nozzle weld cracks due to stress corrosion

Table A2.12 Coding Sheet for Reportable Events for Millstone 1 - 1981

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-01	164391	2/9/81	2/23/81	C	SF-B	Z	-	C	AV	D	C8	A LPCI system piping weld was cracked.
LER-81-02	165884	4/3/81	4/20/81	C	EE	N,NN	P	-	OA	B	S7	Potential single failure discovered in emergency power system.
LER-81-03	166144	4/19/81	5/1/81	B	SD	OO	-	B	BC	G	C8	Two containment instrument isolation valves were closed.
LER-81-04	-	4/21/81	5/5/81	D	RX	BB	-	B	BP	B	C4	A high cooldown rate occurred when the reactor had to be blown down manually.
LER-81-00S	166575	4/1/81	6/17/81	C	IA	-	S	B	EJ	D	N	High count rate on two startup range monitors.
LER-81-05	165924	4/7/81	4/30/81	C	IB	-	U,T	C	EH	D	N	Set point drift in two steam tunnel switches.
LER-81-06	165944	4/17/81	5/6/81	C	MC	-	N	C	EH	D	N	Set point drift in reactor building radiation monitor.
LER-81-07	166243	4/18/81	5/18/81	B	CC	OO	-	C	BA,AQ	D	N	One of six relief valves failed to open.
LER-81-08	168485	4/27/81	8/8/81	D	EE	N	-	C	BF,AT	D	N	Diesel generator tripped on high crankcase pressure due to vacuum break.

Table A2.12 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-09	166632	5/11/81	6/8/81	D	IA	-	N	C	EH	D	N	Set point drift in main steam line radiation monitor.
LER-81-10	166630	5/15/81	6/12/81	D	SF	-	M,T	C	EH	D	N	Set point drift in three break detection pressure switches.
LER-81-01E	167616	5/24/81	7/2/81	D	WE	-	-	B	BU	D	C3	High cobalt and silver activity in oysters.
LER-81-12	166839	6/3/81	7/3/81	D	CE	-	P	C	EH	D	N	Set point drift in isolation condenser time delay relay.
LER-81-13	167165	6/12/81	7/10/81	N	SE	P	-	B	AQ,HB	D	N	Low standby gas treatment flow rate due to fouled filter.
LER-81-15	167182	6/17/81	7/17/81	B	SA	FF	-	B	OC	H	N	Containment air lock leak rate test missed.
LER-81-16	167166	6/18/81	7/17/81	B	IA	OO	P	C	EH	D	N	MSIV closure failed to generate RPS signal due to relay drift.
LER-81-17	167517	6/20/81	7/17/81	B	SA	-	-	-	BU,OK	A	N	Torus oxygen concentration exceeded limit.
LER-81-02E	167613	6/22/81	7/2/81	B	HE	OO	-	B	AX	D	C3	Unmonitored radioactive liquid waste released.

Table A2.12 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-18	167924	6/29/81	7/27/81	B	AB	-	U	C	AC	G	N	Diesel day tank fire detector system failed.
LER-81-19	167923	7/1/81	7/27/81	B	IA	-	M,T	C	EH	D	N	Set point drift in reactor vessel high pressure switch.
LER-81-20	168108	7/14/81	8/6/81	B	EE	NN,OO	-	C	BD,BA	D	C7	Gas turbine generator failed to start due to a stuck valve.
LER-81-00S	168780	-	9/3/81	B	CE	Z	-	B	OC,OK	A	N	Isolation condenser supply line weld not inspected.
LER-81-21	168111	7/10/81	8/11/81	B	IA	-	T	C	EH	D	N	Set point drift in condenser low vacuum switch.
LER-81-22	168555	8/10/81	9/9/81	D	IA	OO	P	C	EH	D	N	MSIV closure failed to generate RPS signal due to relay drift.
LER-81-23	169053	8/10/81	9/9/81	B	IA	-	N	C	EH	D	N	Main steam line hi radiation channel tripped above limit.
LER-81-03E	168043	8/13/81	8/24/81	B	MC	-	N	B	BC,OJ	H	C3	Unmonitored release of liquid effluent.
LER-81-24	168935	8/17/81	9/17/81	B	BB	-	N	C	EH	D	N	Set point drift in reactor building exhaust duct radiation monitor.

Table A2.12 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-25	169185	9/15/81	9/30/81	B	CB	DD	-	B	BF	B	S4	Both reactor recirculation pumps tripped, ATWS was isolated, no alarm.
LER-81-26	169235	9/5/81	10/5/81	B	CE	-	M,T	C	EH	D	N	Set point drift in isolation condenser pressure switch.
LER-81-27	169213	9/6/81	10/6/81	B	SD	OO	T	C	BI,EH	D	N	Containment isolation valve closing time exceeded limit.
LER-81-28	169347	8/11/81	10/7/81	D	EE	F,NN	-	C	BB,BD	D	C7	Breaker failed to close causing no output from gas turbine.
LER-81-29	169346 170103	9/8/81	11/19/81	B	IB	-	I,T	C	AG	D	N	Lo-Lo reactor water level switch was sticking.
LER-81-30	169998	9/14/81	10/13/81	B	IA	-	P	C	EH	D	N	Set point drift in turbine control valve closure relays.
LER-81-31	169337	9/10/81	10/9/81	B	EE	F,NN	-	C	BB,BD	D	N	Gas turbine generator output breaker failed to close.
LER-81-32	169307	9/25/81	10/21/81	B	AB	DD	P	C	BD	D	N	Diesel fire pump failed to start.
LER-81-33	169609	10/6/81	11/5/81	B	SD	-	I,T	C	EH	D	N	Set point drift in reactor vessel Lo water level isolation switch.

Table A2.12 (Continued)

Number	NSIC Accession Number	Event Date	Report Date	Plant Status	System	Equipment	Instrument	Component Status	Abnormal Condition	Cause	Significance Category	Comment
LER-81-34	-	10/13/81	11/12/81	B	IA	-	P	C	EH	D	N	Set point drift in turbine control valve bypass relay.
LER-81-35	171788	11/10/81	12/9/81	B	IA	G	-	B	AP	G	N	Main steam line radiation monitor channel failed when workers bumped cables.
LER-81-36	171790	11/12/81	12/11/81	B	IA	-	M,T	C	EH	D	N	Set point drift in drywell pressure switch.
LER-81-38	171933	11/17/81	12/17/81	B	IA	-	M,T	C	BC,OJ	H	N	Turbine control pressure switch left isolated.
LER-81-39	171599	11/24/81	12/29/81	B	SD	-	P	B	EE	D	N	Relay failure disabled main steam hi flow alarm.
LER-81-40	171601	12/3/81	1/3/82	B	CE	OO,X	-	C	BA,AQ	D	N	Containment isolation valve motor failed.
LER-81-41	172262	12/8/81	1/12/82	B	EE	NN	-	C	AQ	D	N	Gas turbine governor failed.
LER-81-42	172804	12/15/81	1/15/82	B	CF	OO	-	B	AG	D	N	Isolation valve in shutdown cooling line inoperable.

Appendix B. Gas turbine generator failures at Millstone 1

Report No.	Event date	Event description and problem solution
RS 70-4	11-8-70	Gas turbine generator (GTG) fails to start due to low pressure in the lube oil pump. Start-up governing system adjusted.
RS 70-4	12-4-70 (reported)	GTG fails to start due to low pressure in lube oil pump. Two additional immersion heaters installed, set points readjusted.
RS 70-4	1-8-71 (reported)	GTG fails to start within 48 s due to installation error of lube oil discharge line. Line reinstalled.
AO 71-5	2-21-71	GTG fails to start after main turbine trip due to blown fuse and faulty relay. Fuse and relay replaced.
AO 71-8	4-22-71	GTG inoperative due to procedural errors. An operator left a switch in the wrong position. Operators instructed as to proper procedure.
AO-71-12	5-27-71	GTG failed to reach startup speed due to a short circuit in speed switch. Switch replaced.
AO 71-24	11-2-71	GTG failed to ignite due to loose solder connections on a transistor speed switch. Transistor replaced.
AO 71-25	11-30-71	Procedural error caused a loss of heating of the lube oil for the GTG. Operators instructed as to proper operation.
AO 72-3	2-4-72	GTG failed to start after plant trip due to wiring errors in vibration monitor package. Errors fixed.
AO 72-11	3-9-72	GTG failed to start after plant trip due to faulty transistor in speed switch. All transistors replaced.
AO 73-5	4-5-73	Operator disabled GTG by turning wrong controller. Cover placed over controller.
AO 75-4	1-29-75	GTG removed from service to replace faulty relay.
AO 75-8	5-20-75	High generator lube oil temperature due to incorrect valving caused trip of GTG. Valves locked into correct position.

Appendix B (Continued)

Report No.	Event date	Event description and problem solution
AO 76-8	2-29-76	GTG did not start due to improper governor setting. Governor readjusted.
AO 76-10	3-8-76	During daily testing of GTG, unit failed to start due to improper governor setting. Governor readjusted.
RO-76-12	3-15-76	GTG declared inoperable due to governor failure. Switches replaced.
AO 76-29	8-10-76	GTG became inoperable when it could not accept plant load on reactor trip. Cause was incorrect AC feed to GTG auxiliaries. AC feed restructured.
AO 76-30	8-31-76	GTG inoperable on overspeed condition due to faulty speed switch. Switch replaced.
LER 77-27	9-9-77	Spurious noise causes GTG to fail to complete startup sequence. No repair reported.
LER 78-12	5-19-78	GTG failed to start due to incorrect fuel scheduling. No repair reported.
LER 78-14	6-13-78	GTG trips on overspeed due to defective speed switch channel. Speed switch assembly replaced.
LER 78-21	9-14-78	GTG tripped due to faulty speed switch. No repair reported.
LER 78-29	11-22-78	GTG inoperable due to opening of lube oil pump dircuit breaker. Breaker indicator bulb replaced.
LER 79-7	2-14-79	GTG fails to start due to faulty speed switch. Switch replaced.
LER 81-20	7-14-81	GTG failed to start due to rust in the air motor start valve. The valve was cleaned.
LER 81-28	8-11-81	GTG output breaker failed to close due to corrosion on the automatic voltage regulator. The contacting surfaces were cleaned.
LER 81-31	9-10-81	GTG output breaker failed to close due to a wire wound ceramic resistor which failed open. The resistor was replaced.
LER 81-41	12-8-81	GTG governor failed due to contaminated oil. The oil system was flushed with clean oil.

APPENDIX G

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16. ABSTRACT (200 words or less)

The Systematic Evaluation Program was initiated in February 1977 by the U.S. Nuclear Regulatory Commission to review the designs of older operating nuclear reactor plants to reconfirm and document their safety. The review provides (1) an assessment of how these plants compare with current licensing safety requirements relating to selected issues, (2) a basis for deciding on how these differences should be resolved in an integrated plant review, and (3) a documented evaluation of plant safety.

This report documents the review of the Millstone Nuclear Power Station, Unit 1, operated by Northeast Nuclear Energy Company located in Waterford, Connecticut. Millstone Nuclear Power Station, Unit 1 is one of ten plants reviewed under Phase II of this program. This report indicates how 137 topics selected for review under Phase I of the program were addressed. Equipment and procedural changes have been identified as a result of the review. It is expected that this report will be one of the bases in considering the issuance of a full-term operating license in place of the existing provisional operating license.

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