Docket No. 50-245
LS05-82-10-045

OCT 15 1982

Mr. W. G. Counsil, Vice President
Nuclear Engineering and Operations
Northeast Nuclear Energy Company
Post Office Box 270
Hartford, Connecticut 06101

Dear Mr. Counsil:

SUBJECT: INTEGRATED ASSESSMENT SUMMARY - MILLSTONE UNIT 1

A preliminary draft of the Integrated Plant Safety Assessment Report (IPSAR), Chapter 4 (Integrated Assessment Summary) for Millstone 1 is enclosed. This draft has been provided to the ACRS for the SEP Subcommittee meeting to be held on October 26-27, 1982. The staff presentation during that meeting will address the Integrated Assessment reviews of Oyster Creek, Dresden 2 and Millstone 1.

The draft includes your commitments submitted in your response (dated September 22, 1982) to the difference summary and our understanding of your positions as discussed with your staff in meetings held during the Integrated Assessment. Our current schedule is to issue the draft IPSAR by November 5, 1982, and to review any changes from the Integrated Assessment Summary with the ACRS at the December 1982 meeting.

Sincerely,

Dennis M. Crutchfield, Chief
Operating Reactors Branch #5
Division of Licensing

Enclosure:
As stated

cc w/enclosure:
See next page

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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. A more detailed description of each topic with identified differences follows.

The probabilistic risk assessment (PRA) portion of this report as it applies to Millstone Unit 1 has not yet been completed. However, risk perspective using the preliminary results of the Millstone Unit 1 Integrated Reliability Evaluation Program (IREP) study have been incorporated into the review of individual differences. This approach is similar to that used during the integrated assessment reviews of Palisades (NUREG-0820), Ginna (NUREG-0821), and Oyster Creek (NUREG-0822), and in the preliminary draft of Chapter 4 for Dresden Unit 2.* The staff is continuing a more rigorous review of Millstone Unit 1 differences by using the IREP study and calculating the change in risk associated with these differences. This information will be used to supplement the limited approach of identifying separately the "importance of the affected system" and the "change in system availabilities." This is intended to resolve the overall risk importance of marginal changes in system availability for important systems. These results should be available by the end of October 1982.

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,

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*U.S. Nuclear Regulatory Commission, NUREG-0823, "Integrated Plant Safety Assessment Systematic Evaluation Program, Dresden Nuclear Generating Station Unit 2," in preparation.

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 adequate operating procedures and/or system design are provided to cope with the design-basis flood.

The site grade elevation is 14.5 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.

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 4.6) 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 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 is

(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 this 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 water from the gas turbine building would drain toward the Long Island Sound, however, some accumulation near the gas turbine building can still be expected during a PMP because 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 would alleviate local flooding effects. The alternate diesel generator would not be affected by floods; 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. 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. 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 16 hours and these pumps are located in a flood-protected structure. Thus, shutdown can be maintained for 16 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 16 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.

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 1, 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 initiate 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 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 in a licensee event report. 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, 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 they were, 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.

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 with no credit taken for roof 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 is not included on the licensee's list of structures to be inspected.

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 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 separated by a large distance as well as intervening equipment existed 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 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 in the event of damage from tornado missiles.

The licensee disagrees with the staff's position.

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 for 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 due consideration of the recommendations of the turbine manufacturer.

The licensee has agreed to this position.

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

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 in lieu of installing pipe restraints 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. Alternately, the licensee should provide a leakage detection system inside the drywell that conforms to Regulatory Guide 1.45 criteria so that pipe cracks will be detected before they propagate into pipe breaks; therefore, the potential for cascading pipe failures will be acceptably low.

Operating experience with cracking in BWR primary system piping indicates that the systems leak rather than break. Further, the staff has taken the position in the resolution of Unresolved Safety Issue A-2 ("Asymmetric LOCA Loads") for PWR primary systems that leakage detection systems conforming to Regulatory Guide 1.45 are adequate for identifying significant pipe cracking.

Consequently, the staff concludes that the licensee should provide leakage detection capability inside the drywell in accordance with Regulatory Guide 1.45. This action will limit the likelihood that a degraded system could progress to a break and provide adequate protection against potential cascading breaks.

The licensee will submit his analysis of cascading pipe breaks to the staff by November 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 November 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," 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 staff concludes that, similar to the potential for cascading pipe breaks in Section 4.9.1, the implementation of a leakage detection system that conforms to Regulatory Guide 1.45 will provide adequate assurance that pipe cracks can be detected before a degraded system could progress to a break; therefore, the potential for an unstable pipe rupture leading to a pipe whipping into the drywell liner is acceptably low.

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 November 15, 1982. The evaluation of conformance to Regulatory Guide 1.45 is discussed in Section 4.16.

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) 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 November 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 (i.e., seismic Category I).

No stress data are available to demonstrate that these piping systems between the containment penetration and the isolation valve outside containment meet the stress limits of BTP MEB 3-1. 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, the probabilistic risk assessment rated the importance to risk of pipe breaks between the containment penetration and the isolation valve outside containment as 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 motor-operated valves attached to small piping (4 in. or smaller) 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.

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 proposed to provide the staff with additional information on the anchorage design. This information will be submitted by October 15, 1982.

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 will require that the licensee submit the analysis of the recirculation pump snubber supports.

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.

The staff will require 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.

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. This 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 preliminary 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.

In a letter dated April 12, 1982, 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 and where necessary will modify or bypass thermal overload protection devices by January 3, 1983.

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. This occurs 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 impact 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 of 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 preliminary 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 (S2 LOCA as described in Appendix D). 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, according to the preliminary results of the Millstone Unit 1 IREP study, small LOCAs account for 70% of the total core-melt frequency. Therefore, preventing leaks from becoming breaks could be important to risk. However, this limited risk assessment does not address the staff's principal concern with respect to leakage detection, which is not the S2 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 Oyster Creek, plant-specific evaluations of the emergency condenser inlet and return lines 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) System Sensitivity

The existing system at Millstone Unit 1 is capable of detecting a 1-gpm leak in 8 hours and does not meet the current requirement of being able to detect a leak of 1 gpm in 1 hour.

(2) Seismic Qualification

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 to the operating-basis earthquake.

(3) Testability

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) Number of Systems

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

(5) Operability Requirements

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 able to detect 1 gpm in 1 hour.

(3) The method should be testable during operation.

(4) 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 proposed 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. Preliminary PRA results 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.

It should be noted, however, 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 next 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 main condenser. If the relief valve does not have enough capacity or if it fails to open, the system would break producing a LOCA outside containment.

A preliminary PRA has shown that assuming the pressure relief valve is sufficiently sized, the frequency of an interfacing system LOCA through this system is about 10^{-7}/year and the issue has low importance to risk. However, if the pressure relief valve is not sufficiently sized, the LOCA frequency is about 10^{-3}/year and the issue has high importance to risk.

It is the staff's position that the licensee install an independent pressure interlock or provide justification for not doing so.

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 Conductivity Limits

Millstone Unit 1 does 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 Technical Specifications to incorporate the water chemistry limits for pH and chlorides of Regulatory Guide 1.56. The licensee will incorporate the limits for conductivity also or he will provide justification for not doing so. The new proposed 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 reactor water cleanup (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 <u>Topic VI-4, Containment Isolation System</u>

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.

Preliminary PRA results 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 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
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 mecnanical 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 agrees with 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 provided 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
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

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	-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 similar to an ESF system, is a safety system 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 valve 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
X-204	Cooling water return lines (2) that branch off in between takeoffs to containment spray pumps

The staff will require 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.

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:

(1) 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 1, 1982.

(2) 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, the heat transfer to the environment is accomplished by using sea water through the ESWS from the Long Island Sound to remove heat from the containment. This decreases the heat storage in the containment, thereby preventing containment rupture. The only system that provides this function in response to the LOCA is the LPCI system when used in the containment cooling mode.

According to the FSAR (page VI-2.21), the containment cooling function can be 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 and consequent loss of core-cooling capability.

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. 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. 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.

There can also 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.

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

(1) Buses 2A-3NE, 2-3NE, and 22A-1, the 12-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.

A preliminary PRA of Millstone Unit 1 showed that the presence of automatic bus transfers (ABTs) does not contribute significantly to the failure of the ac power system; however, emergency ac failure is contained in dominant accident sequences. It is the staff's position that these ABTs be removed or the circuits be otherwise modified to ensure that faults (i.e., shorts to ground) will not be transferred.

The licensee has proposed to evaluate the existing ABTs and identify the corrective actions by October 29, 1982. The staff finds this acceptable.

(2) 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 the corrective actions by October 29, 1982.

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

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 Test 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 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 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 the other APRM channels or provide justification for not doing so.

4.24.2 Channel Functional Test Frequency

For the following channels, a channel functional test is performed monthly by plant procedure; however, the Technical Specifications allow a quarterly test frequency.

(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

Current licensing criteria require a monthly channel functional test. It is the staff's position that testing requirements that are important to safety should be included in the facility Technical Specifications so that the testing frequency is consistent with GE Standard Technical Specifications.

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 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:

(1) 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 licensee has proposed to conduct tests to determine if adequate isolation exists between (a) the nuclear flux monitoring system and the process recorders and indicating instruments and (b) 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 November 30, 1982. The staff finds this proposal acceptable.

(2) 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 fall 1982 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.

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 acceptable. Backfitting is not required.

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 satisfies 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 ac independent 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.

The licensee has agreed to develop operating procedures for a degraded voltage event to ensure that damage to safety-related equipment does not occur. Such actions would include starting the diesel generator or gas turbine to provide adequate voltage to vital equipment. These procedures will be implemented by ___________________. The staff finds this acceptable.

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 pumps.

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 next 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 leak 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 them 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.

There have been a total of 31 gas turbine generator failures reported 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 ones 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 concluded that a significant contributor to core-melt events is a loss-of-normal-ac-power event. Loss of normal ac power accounts for 41% of the total core-melt probability. The major causes of core melt, during loss of normal ac power, 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.

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.

Table 4.2 Gas turbine generator failures

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.

Table 4.2 (Continued)

Report No.	Event date	Event description and problem solution
AO 75-8	5/20/75	High generator lube oil temperature resulting from incorrect valving caused trip of GTG. Valves locked into current position.
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 [illegible] stuck shutoff valve for the air start motor. Th[illegible]use was accumulation of rust in the valve interna[illegible] Valve cleaned and reinstalled.

Table 4.2 (Continued)

Report No.	Event date	Event description and problem solution
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 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.

Since many of the gas turbine failures may 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."

4.28.3 Generator Trips

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

(1) loss of excitation
(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 as is currently done on the diesel generator.

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

4.28.4 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 on _____.

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 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 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.

A preliminary PRA performed to determine the importance to risk of dc instrumentation, indication, and alarms determined that additional monitoring devices would substantially reduce the dc bus unavailability. This reduction is due almost equally to a reduction in breaker unavailability and battery unavailability. In the Millstone Unit 1 IREP analysis, the cut sets, which included dc battery failures, contributed less than 5% to the total risk resulting from core melt; however, the proposed improvement in dc system availability would virtually eliminate the contribution of dc battery faults to the risk of core melt. This issue is, therefore, of high risk importance.

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 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.

At Millstone Unit 1, there are control room indications for battery breaker open and charger output current. The staff will require that battery current also be alarmed or instrumentation provided in the control room.

The licensee has not given a position on this requirement.

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.

For the reasons indicated, backfitting is not recommended pending acceptable results from the review of Topic II-4.F because 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:

(1) 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.

As under Topic VI-7.A.3 (Section 4.22), 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.

(2) 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.

(3) 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) 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 an 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 plant shut down in September 1982 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.)

(3) PRA studies of BWRs indicate that feedwater controller transients without bypass are of little importance insofar as risk is concerned.

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 maximum 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) The costs associated with hardware modifications are not justified on the basis of realistic estimates of consequences.

(3) Experience has shown that small-line breaks are low probability events.

(4) Risk assessments have shown that events that do not involve core melt are not important to risk.

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 are acceptably low and is necessary to establish appropriate limiting conditions for operation in the event of fuel failures.

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. If the existing Technical Specification limits for primary coolant activity are used, the potential offsite doses would substantially exceed the applicable dose 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.