NUREG-0876
Supplement No. 5

Safety Evaluation Report
related to the operation of Byron Station, Units 1 and 2

Docket Nos. STN 50-454 and STN 50-455

Commonwealth Edison Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

October 1984

NOTICE

Availability of Reference Materials Cited in NRC Publications

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

1. The NRC Public Document Room, 1717 H Street, N.W.
   Washington, DC 20555
2. The NRC/GPO Sales Program, U.S. Nuclear Regulatory Commission,
   Washington, DC 20555
3. The National Technical Information Service, Springfield, VA 22161

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

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

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

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

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

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

Single copies of NRC draft reports are available free, to the extent of supply, upon written request to the Division of Technical Information and Document Control, U.S. Nuclear Regulatory Commission, Washington, DC 20555.

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

GPO Printed copy price: $6.00

NUREG-0876
Supplement No. 5

Safety Evaluation Report
related to the operation of Byron Station, Units 1 and 2

Docket Nos. STN 50-454 and STN 50-455

Commonwealth Edison Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

October 1984

ABSTRACT

Supplement No. 5 to the Safety Evaluation Report related to Commonwealth Edison Company's application for licenses to operate the Byron Station, Units 1 and 2, located in Rockvale Township, Ogle County, Illinois, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement reports the status of certain items that had not been resolved at the time of publication of the Safety Evaluation Report. Because of the favorable resolution of the items discussed in this report, the staff concludes that there is reasonable assurance that the facility can be operated by the applicant without endangering the health and safety of the public.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

1 INTRODUCTION AND GENERAL DESCRIPTION OF FACILITY

1.1 Introduction

The Nuclear Regulatory Commission's Safety Evaluation Report (SER) (NUREG-0876) in the matter of Commonwealth Edison Company's application to operate the Byron Station Units 1 and 2 was issued in February 1982. The first supplement (SSER) to that SER was issued in March 1982, the second was issued in January 1983, the third was issued in November 1983, and the fourth was issued in May 1984. In the supplements, the staff identified items that were not yet resolved with the applicant. These items were categorized as

(1) Outstanding items which needed resolution prior to the issuance of an operating license.

(2) Items for which the staff had completed its review and had determined positions for which there appeared to be no significant disagreement between the applicant and the staff. Further information was needed, however, to confirm these positions.

(3) Items for which the staff had taken position and would require implementation and/or documentation after the issuance of the operating license. These would be conditions to the operating license.

The purpose of this fifth supplement to the SER is to provide the staff evaluation of the open items that have been resolved and to address changes to its safety evaluation that resulted from the receipt of additional information from the applicant.

Copies of this SER supplement are available for inspection at the NRC Public Document Room, 1717 H Street, NW, Washington, D.C., and at the Rockford Public Library, Rockford, Illinois. Single copies may be purchased from the sources indicated on the inside front cover.

The NRC Project Manager assigned to the Operating License application for Byron Station is Leonard N. Olshan. Mr. Olshan may be contacted by calling (301) 492-7070 or writing:

Leonard N. Olshan
Division of Licensing
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

1.7 Summary of Oustanding Items

The current status of the outstanding items listed in the original SER follows:

(1) Additional information to confirm pipeline foundation design (Section 2.5) - Closed in this supplement.

(2) Turbine missile evaluation (Section 3.5.1.3) - Closed in this supplement.

(3) High- and moderate-energy pipe break analysis outside containment (Section 3.6.1) - Closed in Supplement 2.

(4) Pump and valve operability assurance (Section 3.9.3.2) - Closed in this supplement.

(5) Baseplate flexibility and anchor bolt loading (Section 3.9.3.4) - Closed in Supplement 3.

(6) Seismic and dynamic qualification of equipment (Section 3.10) - Closed in this supplement.

(7) Environmental qualification of electrical equipment (Section 3.11) - Closed in this supplement.

(8) Improved thermal design procedures (Section 4.4.1) - Closed in this supplement.

(9) TMI action item II.F.2: Inadequate Core Cooling Instrumentation (Section 4.4.7) - Closed in this supplement.

(10) Steam generator flow-induced vibrations (Section 5.4.2) - Closed in this supplement.

(11) Reactor pessure vessel forces and moments analysis (Section 6.2.1.2) - Closed in Supplement 2.

(12) Equipment and floor drainage system for internal flood protection (Section 9.3.3) - Closed in Supplement 2.

(13) Fire protection program (Section 9.5.1) - Closed in this supplement.

(14) Residual moisture in diesel air start piping (Section 9.5.6) - Closed in Supplement 1.

(15) Volume reduction system (Sections 11.1 and 11.4.2) - License Condition 23.

(16) Emergency preparedness plans and facilities (Section 13.3) - Closed in Supplement 4.

(17) Control room human factors review (Section 18.0) - Closed in Supplement 4.

(18) Conformance of ESF filter system to RG 1.52 (Section 6.5.1) - Closed in this supplement.

1.8 Confirmatory Issues

Confirmatory Issues 8, 19, 20, 21, 28, 34, 37 and 38 from the SER are being closed in this supplement. The current status of the confirmatory issues follows:

(1) Confirmatory analysis to verify river screenhouse seismic response analysis (Section 2.5.4.3) - Open.

(2) Category 1 manhole protection from tornado missiles (Section 3.5.3) - Closed in Supplement 1.

(3) Analysis of tangential shear on containment (Section 3.8.1) - Errata, deleted in Supplement 2.

(4) Piping vibration test program (Section 3.9.2.1) - Open.

(5) Snubber inspection and testing program details (Section 3.9.2.1) - Closed in Supplement 1.

(6) Seismic reevaluation of components and supports (Section 3.9.2.2) - Closed in Supplement 1.

(7) Basis for steam generator tube plugging (Section 3.9.3.1) - Closed in Supplement 3.

(8) Inservice testing of pumps and valves (Section 3.9.6) - Closed in this supplement.

(9) Loose parts monitoring system (Section 4.4.6) - Closed in Supplement 2.

(10) Code cases for control valves (Section 5.2.1) - Closed in Supplement 1.

(11) Fracture toughness data for Byron Unit 2 (Section 5.3.1) - Closed in Supplement 2.

(12) Steam generator tube surveillance (Section 5.4.22) - Closed in Supplement 2.

(13) Boration to cold shutdown analysis (Section 5.4.3) - Closed in Supplement 2.

(14) Cooldown rate with RHR (Section 5.4.3.1) - Closed in Supplement 2.

(15) RCS vent procedures (Section 5.4.5) - Closed in Supplement 2.

(16) Charging pump deadheading (Section 6.3.2), (Section 7.3.2.13) - Open (Interim closure in Supplement 4 for Unit 1).

(17) Containment differential pressure analysis (Section 6.2.1) - Closed in Supplement 2.

(18) Containment sump instrumentation (Section 6.2.1.1) - Closed in Supplement 2.

(19) Minimum containment pressure analysis for performance capabilities of ECCS (Section 6.2.1.5) - Closed in this supplement.

(20) Containment leakage testing vent and drain provisions (Section 6.2.6) - Closed in this supplement.

(21) Confirmatory test for sump design (Section 6.3.4.1) - Closed in this supplement.

(22) Upper head temperature verification (Section 6.3.5.1) - Closed in Supplement 2.

(23) IE Bulletin 80-06 (Section 7.3.2.3) - Open.

(24) Test jacks for P-4 interlock test (Section 7.3.2.9) - Closed in Supplement 2.

(25) Remote shutdown capability (Section 7.4.2.2) - Open.

(26) Steam generator pressure control (Section 7.4.2.3) - Closed in Supplement 2.

(27) Switchover from injection to recirculation (Section 7.6.2.3) - Closed in Supplement 3.

(28) TMI Item II.K.3.1 (Section 7.6.2.7); III.D.1.1 (Section 9.3.5); II.K.2.17 (Section 15.5); II.D.I (3.9.3.3); II.K.2.17 - Closed in Supplement 2, others closed in this supplement.

(29) Viewing the installation and arrangement of electrical equipment (Section 8.1) - Closed in Supplement 3.

(30) Independence of redundant electrical safety equipment (Section 8.4.4) - Closed in Supplement 2.

(31) Electrical distribution system voltage verification (Section 8.2.4) - Open.

(32) Combined health physics and chemistry organization (Section 12.5.1) - Closed in Supplement 3.

(33) Revision to Physical Security Plan (Section 13.6) - Closed in Supplement 4.

(34) RCP rotor seizure and shaft break (Section 15.3.6) - Closed in this supplement.

(35) Anticipated Transients Without Scram (ATWS) (Section 15.6) - Closed in Supplement 4.

(36) Applicant compliance with the Commission's regulations (Section 1.1) - Closed in Supplement 4.

(37) SWS process control program (Section 11.4.2) - Closed in this supplement.

(38) Noble gas monitor (Section 11.5.2) - Closed in this supplement.

1.9 License Conditions

License Conditions 1, 2, 3, 8, 11 and 12 were identified in the previous SER and supplements, but are no longer required. Nine license conditions have been added.

Following is the current status of the license conditions:

(1) Groundwater monitoring program (Section 2.4.6) - Closed in this supplement.

(2) Masonry walls (Section 3.8.3) - Closed in this supplement.

(3) Preservice and Inservice inspection program (Sections 5.2.4 and 6.6) - Closed in this supplement.

(4) Response time testing (Section 7.2.2.5) - Closed in Supplement 4.

(5) Post accident monitoring (Section 7.5.2.2) - Closed in Supplement 2.

(6) Modifications to permit isolation of non-IE loads from Class 1E power sources (Section 8.3.2) - Errata, deleted in Supplement 1.

(7) Compliance with Appendix R of 10 CFR 50, Fire Protection (Section 9.5.1).

(8) Steam valve inservice inspection (Sections 3.5.1.3, 10.2) - Closed in this supplement.

(9) Implementation of secondary water chemistry monitoring and control program as proposed by the Byron/Braidwood FSAR (Section 10.3.2) - Closed in Supplement 4.

(10) Personnel on shift with previous commercial PWR experience during startup phase (Section 13.1.2.1) - Closed in Supplement 4.

(11) TMI Item II.B.3 Postaccident Sampling (Section 9.3.2) - Closed in this supplement.

(12) Natural circulation testing (Section 5.4.3) - Closed in this supplement.

(13) Control of heavy loads (Section 9.1.5).

(14) Upgrade emergency operating procedures (Section 13.5.2).

(15) Relocate control room controls (Section 18.2).

(16) Emergency planning (Section 13.3).

(17) Seismic and dynamic qualification (Section 3.10).

(18) Equipment qualification (Section 3.11)

(19) Iodine particulate sampling (Section 11.5.2).

(20) Reliability of diesel generators (Section 9.5.4.1).

(21) Feedwater flow measurement accuracy monitoring (Section 4.4.1).

(22) Protection against postulated breaks or cracks in high- and moderate-energy lines (Section 3.6.2).

(23) Volume reduction system (from Outstanding Issue 15).

(24) Shift advisors (Section 13.1.2).

(25) Turbine maintenance program (Section 3.5.1).

2 SITE CHARACTERISTICS

2.4 Hydrology

2.4.6 Design Basis for Subsurface Hydrostatic Loading

The original SER identifies a license condition regarding a groundwater monitoring program for area 11 of the ESW pipeline.

A design basis groundwater level was not identified for the ESW pipeline. The staff determined that one area (area 11) of the pipeline had soils that could be subject to liquefaction if subjected to a seismic event when the groundwater was above elevation 850 ft msl. The applicant contended that the groundwater would not rise above elevation 825 to 830 ft msl. It was the staff's position that the applicant had not provided sufficient bases to preclude a critical groundwater level of 850 ft msl with any reasonable assurance. Thus the staff imposed a groundwater monitoring program in area 11 of the ESW pipeline for the purpose of obtaining additional information that would facilitate long term groundwater projections.

Four observation wells were installed (March 18-23, 1982) between ESW pipeline stations 45+20 N and 53+00N. Two of the wells (OW-1 and OW-2) were installed to detect and measure the presence of perched groundwater occurring in the soils above the bedrock surface. The other two wells (OW-3 and OW-4) were installed to measure groundwater level occurring in the upper portion of the dolomite bedrock.

By letters dated March 16, 1984 and October 1, 1984 the applicant submitted results of the monitoring program and analyses to show that the groundwater level in area 11 will not rise to the critical level of 850 ft msl. The four monitoring wells were dry during the entire period, which reflects a groundwater level below elevation 809 ft msl. In addition a large portion of the recharge area for the perched groundwater has been paved which will preclude infiltration and future reduce the potential for increases in groundwater level.

The staff has reviewed all the data and analyses and concurs with the applicant that groundwater in area 11 will not reach the critical elevation of 850 ft msl; thus, the groundwater monitoring program may be terminated and License Condition 1 is no longer needed.

2.5 Geology and Seismology

2.5.2 Seismology

The verification of the seismic analyses of the river screenhouse foundation was Confirmatory Item 1 in the original SER. In order to perform these analyses the vibratory ground motion from the safe shutdown earthquake is required.

The safe shutdown earthquake for the Byron Station site is based on the postulated occurrence of a Maximum Modified Mercalli Itensity VIII (body wave magnitude 5.8) earthquake near the site. The staff's position as stated in the original SER is that a Regulatory Guide 1.60 response spectrum with a high frequency anchor of 0.20g at the foundation level of structures founded on rock is an adequately conservative representation of the vibratory ground motion from this size earthquake. This determination was made by comparing site specific response spectra developed for rock sites from magnitude 5.8 earthquake with the 0.20g Regulatory Guide 1.60 spectrum.

The river screenhouse is on soil about 100 feet deep which has shear wave velocities ranging from about 500 feet per second to about 1200 feet per second. This soil overlies sandstone with a shear wave velocity of about 9500 feet per second. The presence of this soil and the relatively high velocity contrast between the soil and the rock may amplify the vibratory ground motion. Because of the lack of data recorded under these geologic conditions for earthquakes of the correct magnitude it is undesirable to attempt to calculate a soil site-specific response spectrum to be used as input at the foundation level of the river screenhouse. To mitigate this problem the seismic analysis of the river screenhouse will be performed by a soil structure interaction (SSI) analsysis. This section of the safety evaluation addresses the seismic input for the SSI analysis. The review of the SSI analysis will be addressed in a future supplement.

An appropriate input to be used at the rock surface in the SSI analysis is characterized by the site-specific spectrum of a magnitude 5.8 earthquake for a rock site. For this purpose, the staff plans to use the 84th percentile rock spectrum for a magnitude 5.8 earthquake generated by Lawrence Livermore National Laboratory as part of the NRC sponsored Seismic Hazard Analysis Program (NUREG/CR-1581, Volume 4).

2.5.4 Stability of Subsurface Materials and Foundations

2.5.4.3 Foundation Stability

2.5.4.3.3 Essential Service Water Makeup Pipeline

The original SER stated that additional information about the subsurface conditions beneath the essential service water (ESW) pipeline was required to confirm the adequacy of the foundation and design for the pipeline.

The applicant performed a geotechnical exploration program in August 1982 and the report was submitted by letter dated October 27, 1982. The staff review of that report concluded that the rock support for the pipeline in areas 9 and 11 was adequate, but a soil supported section in area 12 had not been adequately addressed. Thus, the applicant also provided additional information by letter dated August 10, 1984, which showed that area 12 had been preloaded during the construction of the switchyard. The fill placement and compaction of soil in the switchyard near area 12 occurred between May 1975 and October 1975 and the construction of the ESW pipeline started in July 1977. This loading would cause consolidation of the compressible foundation soils in area 12. Since the soil loads due to the ESW pipeline construction are almost equal to the preload of soil loads, the differential settlement resulting from the pipeline

placement would be expected to be minimal and would not cause abnormal distress to the pipeline in area 12. Therefore, Outstanding Item 1 is considered closed.

2.5.4.3.4.1 Liquefaction Potential at the River Screenhouse

As stated in the original SER, a confirmatory seismic analysis of the river screenhouse using more realistic upper bound shear moduli values obtained from laboratory tests is required. After determining that their laboratory tests were invalid, the applicant performed a crosshole survey to determine the in situ shear moduli in January 1984 and submitted additional information February 28, 1984 and April 18, 1984. The staff conducted a design audit of the river screenhouse in June 1984.

The staff's evaluation of the applicant's submittal and the results of the audit revealed that the applicant had not performed a confirmatory analysis to demonstrate that the recently measured shear moduli would not invalidate the present seismic design of the river screenhouse. The structural analyses were not clear and the applicant could not provide a satisfactory explanation of its methods or results during the staff audit. Brookhaven National Laboratory has been requested by the NRC to review, in detail, the seismic analysis and design of the river screenhouse so that this issue can be adequately documented and resolved. The results of this review will be reported in a future SER Supplement to be issued after issuance of an operating license. Thus, Confirmatory Issue 1 remains open.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS AND COMPONENTS

3.5 Missile Protection

3.5.1 Missile Selection and Description

3.5.1.3 Turbine Missiles

3.5.1.3.1 Review Basis

3.5.1.3.1.1 Introduction

During the past several years the results of turbine inspections at operating nuclear facilities indicate that cracking to various degrees has occurred at the inner radius of turbine disks, particularly those of Westinghouse design. Within this time period, there has actually been a Westinghouse turbine disk failure at one facility owned by the Yankee Atomic Electric Company. Furthermore, recent inspections of General Electric turbines have also resulted in the discovery of disk keyway cracks. Stress corrosion has been identified by both manufacturers as the operative cracking mechanism.

The staff has followed these developments closely. The staff's primary safety objective is the prevention of unacceptable doses to the public from releases of radioactive contaminants that could be caused by damage to plant safety-related structures, systems and components due to missile generating turbine failures. Based on previous staff reviews and various estimates by others (see Bush, 1973; and Twisdale, Dunn and Frank, 1982) for a variety of plant layouts, the staff concludes that "if a turbine missile is generated" the probability of unacceptable damage to safety-related structures, systems, and components is in the neighborhood of 10^{-3} or 10^{-2} per year depending on whether the turbine orientation is favorable or unfavorable. In view of this and operating experience, the staff has shifted the review emphasis to the prevention of missile generating turbine failures. In keeping with this shift of emphasis, the staff has recently set turbine missile generation probability guidelines for determining turbine disk ultrasonic inservice inspection frequencies, and turbine control and overspeed protection systems maintenance and testing schedules. No change in safety criteria is associated with this change in review emphasis. The major domestic turbine manufacturers are already in the process of establishing models and methods for calculating turbine missile generation probabilities for their respective turbine generator systems.

This shift of emphasis helps improve turbine generator system reliability by focusing on review and evaluation of the probability of missile generating turbine failure, and in the process provides a logically consistent method for establishing inservice inspection and testing schedules. Furthermore, it reduces considerably the analytical burden placed on licensees by eliminating the need for elaborate and ambiguous analyses of strike and damage probabilities, and at the same time better assures the protection of public health and safety by better maintaining turbine system integrity.

3.5.1.3.1.2 Criteria that Must be Met to Demonstrate Compliance With Regulations

According to General Design Criterion 4 of Appendix A to 10 CFR Part 50, nuclear power plant structures, systems, and components important to safety shall be appropriately protected against dynamic effects, including the effects of missiles. Failures of large steam turbines of the main turbine generator have the potential for ejecting large high energy missiles that can damage plant stuctures, systems, and components. The overall safety objective of the staff is to assure that structures, systems, and components important to safety are adequately protected from potential turbine missiles. Of those systems important to safety, this topic is primarily concerned with safety-related systems; i.e., those structures, systems, or components necessary to perform required safety functions and to ensure:

1. The integrity of the reactor coolant pressure boundary.

2. The capability to shut down the reactor and maintain it in a safe shutdown condition, or

3. The capability to prevent accidents that could result in potential offsite exposures that are a significant fraction of the guideline exposures of 10 CFR Part 100, "Reactor Site Criteria."

Typical safety-related systems are listed in Regulatory Guide (RG) 1.117.

The probability of unacceptable damage due to turbine missiles (P_4) is generally expressed as the product of (a) the probability of turbine failure resulting in the ejection of turbine disk (or internal structure) fragments through the turbine casing (P_1), (b) the probability of ejected missiles perforating intervening barriers and striking safety related structures, sytems, or components (P_2), and (c) the probability of struck structures, systems, or components failing to perform their safety function (P_3).

According to NRC guidelines stated in Section 2.2.3 of the Standard Review Plan (SRP) NUREG-0800, and RG 1.115, the probability of unacceptable damage from turbine missiles should be less than or equal to about one chance in ten million per year for an individual plant, i.e., $P_4 \leq 10^{-7}$ per year.

3.5.1.3.1.3 Past Procedures for Demonstrating Compliance with Regulations

In the past, analyses for construction permit (CP) and operating license (OL) reviews assumed the probability of missile generation (P_1) to be approximately 10^{-4} per turbine year, based on the historical failure rate (see Bush, 1973). The strike probability (P_2) was estimated in SRP Section 3.5.1.3 based on postulated missile sizes, shapes, and energies, and on available plant-specific information such as turbine placement and orientation, number and type of intervening barriers, target geometry, and potential missile trajectories. The damage probability (P_3) was generally assumed to be 1.0. The overall probability of unacceptable damage to safety related systems (P_4), which is the sum over all targets of the product of these probabilities, was then evaluated for compliance with the NRC safety objective. This logic places the regulatory emphasis on the strike probability, i.e., having established an individual

plant safety objective of about 10^{-7} per year, or less, for the probability of unacceptable damage to safety related systems due to turbine missiles, this procedure requires that P_2 be less than or equal to 10^{-3}.

It is well known that nuclear turbine disks crack (see NUREG/CR-1844, March 1981; and PNO-III-81-04 on Monticello, November 24, 1981) and that turbine stop and control valves fail (see LER 82-132, Docket No. 50-361, November 19, 1982; and Burns, 1977), and that disk ruptures can result in the generation of high-energy missiles (Kalderon, 1972). Furthermore, analyses (NUREG/CR-1884, and Clark, Seth, and Shaffer, 1981) clearly demonstrate the large effects of inservice testing and inspection frequencies on missile generation probabilities (P_1). It is the staff's view that sufficiently frequent turbine testing and inspection are the best means of assuring that the criteria on the probability on unacceptable damage to safety related structures, systems, and components P_4 presented in Subsection 3.5.1.3.1.2 is met. Therefore, it is prudent for turbine manufacturers to perform, and the staff to review, analyses of turbine reliability, which include known and likely failure mechanisms, expressed as a function of time (i.e., inservice inspection or test intervals).

While the calculation of strike probability is not difficult in principle, for the most part reducing to a straightforward ballistics analysis, it presents a problem in practice. The problem stems from the fact that numerous modeling approximations and simplifying assumptions are required to make tractable the incorporation into acceptable models of available data on the (a) properties of missiles, (b) interactions of missiles with barriers and obstacles, (c) trajectories of missiles as they interact with and perforate (or are deflected by) barriers, and (d) identification and location of safety-related targets. The particular approximations and assumptions made tend to have a large effect on the resulting value of P_2. Similarly, a reasonably accurate specification of the damage probability (P_3) is not a simple matter due to the difficulty of defining the missile impact energy required to render given safety-related systems unavailable to perform their safety function, and the difficulty of postulating sequences of events that would follow a missile producing turbine failure.

3.5.1.3.1.4 New Procedure for Demonstrating Compliance with Regulations

The new approach places on the applicant the responsibility for demonstrating and maintaining a NRC specified turbine reliability by appropriate inservice inspection and testing throughout plant life. This shift of emphasis necessitates that the applicant show capability to have volumetric (ultrasonic) examinations performed which are suitable for inservice inspection of turbine disks and shaft, and to provide reports for staff review and approval which describe their methods for determining turbine missile generation probabilities.

Westinghouse and General Electric, on behalf of applicants, are preparing reports for staff review and approval which describe methods for determining turbine missile generation probabilities for their respective turbines. The design speed missile generation probability is to be related to disk design parameters, material properties, and the inservice volumetric (ultrasonic) disk inspection interval (for example, see Clark, 1981). The destructive overspeed missile generation probability is to be related to the turbine governor and overspeed protection system's speed sensing and tripping characteristics, the design and arrangement of main steam control and stop valves and the reheat

steam intercept and stop valves, and the inservice testing and inspection intervals for systems components and valves (for example, see Burns, 1977). Following the submittal of such reports to the NRC for review and approval, the manufacturer will provide applicants and licensees with tables of missile generation probabilities versus time (inservice volumetric disk inspection interval for design speed failure, and inservice valve testing interval for destructive overspeed failure) for their particular turbine, which are then to be used to establish inspection and test schedules which meet NRC safety objectives.

Due to the uncertainties involved in calculating P_2 (see Section 3.5.1.3.1.3 of this SER), the staff concludes that P_2 analyses are "ball park" or "order of magnitude" type calculations only. Based on simple estimates for a variety of plant layouts (for examples see Bush, 1973; and Twisdale, Dunn, and Frank, 1982), the staff further concludes that the strike and damage probability product can be reasonably taken to fall in a characteristic narrow range which is dependent on the gross features of turbine generator orientation; for favorably oriented turbine generators P_2 P_3 tend to lie in the range 10^{-4} to 10^{-3}, and for unfavorably oriented turbine generators P_2 P_3 tend to lie in the range 10^{-3} to 10^{-2}. For these reasons (and due to weak data, controversial assumptions, and modeling difficulties), in the evaluation of P_4, the staff gives credit for the product of the strike and damage probabilities of 10^{-3} for a favorably oriented turbine and 10^{-2} for an unfavorably oriented turbine, and does not encourage calculations of them. These values represent the staff's opinion of where P_2 P_3 lie based on calculations done by the staff and the results of calculations done by others.

It is the staff's view that the NRC safety objective with regard to turbine missiles is best expressed in terms of two sets of criteria applied to the missile generation probability (see Table 1). One set of criteria is to be applied to favorably oriented turbines, and the other is to be applied to unfavorably oriented turbines. Applicants and licensees, with turbines from manufacturers who have had reports describing their methods and procedures for calculating turbine missile generation probabilities reviewed and accepted by the NRC, are expected to meet the set of criteria appropriate to their turbine orientation, as shown in Table 1.

3.5.1.3.1.5 Alternative Procedure for Demonstrating Compliance with Regulations

Applicants and licensees, with turbines from manufacturers who have not yet submitted reports to the NRC describing their methods and procedures for calculating turbine missile generation probabilities or who have submitted reports which are still being reviewed by the NRC, are expected to meet the following alternative criteria, regardless of turbine orientation:

A. The inservice inspection program employed for the steam turbine rotor assembly is to provide assurance that disk flaws that might lead to brittle failure of a disk at speeds up to design speed will be detected. The turbine rotor design should be such as to facilitate inservice inspection of all high stress regions, including disk bores and keyways, without the need for removing the disks from the shaft. The volumetric inservice inspection interval for the steam turbine rotor assembly is to be established according to the following guidelines:

Table 1. Reliability Criteria

Probability, yr^{-1}		
Favorably oriented	Unfavorably oriented	Required licensee action
A. $P_1 < 10^{-4}$	$P_1 < 10^{-5}$	This is the general, minimum reliability requirement for loading the turbine and bringing the system on line.
B. $10^{-4} < P_1 < 10^{-3}$	$10^{-5} < P_1 < 10^{-4}$	If during operation this condition is reached, the turbine may be kept in service until the next scheduled outage, at which time the licensee is to take action to reduce P_1 to meet the appropriate A criterion (above) before returning the turbine to service.
C. $10^{-3} < P_1 < 10^{-2}$	$10^{-4} < P_1 < 10^{-3}$	If during operation this condition is reached, the turbine is to be isolated from the steam supply within 60 days, at which time the licensee is to take action to reduce P_1 to meet the appropriate A criterion (above) before returning the turbine to service.
D. $10^{-2} < P_1$	$10^{-3} < P_1$	If at any time during operation this condition is reached, the turbine is to be isolated from the steam supply within 6 days, at which time the licensee is to take action to reduce P_1 to meet the appropriate A criterion (above) before returning the turbine to service.

1. The initial inspection of a new rotor or disk should be performed before any postulated crack is calculated to grow to more than 1/2 the critical crack depth. If the calculated inspection interval is less than the scheduled first fuel cycle, the licensee should seek the manufacturer's guidance on delaying the inspection until the refueling outage. If the calculated inspection interval is longer than the first fuel cycle, the licensee should seek the manufacturer's guidance for scheduling the first inspection at a later refueling outage.

2. Disks that have been previously inspected and found to be free of cracks or that have been repaired to eliminate all indications should be reinspected using the same criterion as for new disks, as described in (1), calculating crack growth from the time of the last inspection.

3. Disks operating with known and measured cracks should be reinspected before 1/2 the time calculated for any crack to grow to 1/2 the critical crack depth. The guidance described in (1) should be used to set the inspection date based on the calculated inspection interval.

4. Under no circumstances is the volumetric inservice inspection interval for LP disks to exceed approximately 3 years or 3 fuel cycles.

Inspections during these refueling or maintenance shutdowns should consist of visual, surface, and volumetric examinations, according to the manufacturer's procedures, of all normally inaccessible parts such as couplings, coupling bolts, LP turbine shafts, blades, and disks, and HP rotors. Shafts and disks with cracks of depth near to or greater than 1/2 the critical crack depth are to be repaired or replaced. All cracked couplings and coupling bolts should be replaced.

B. The inservice inspection and test program employed for the governor and overspeed protection system should provide assurance that flaws or component failures in the overspeed sensing and tripping subsystems, in the main steam control and stop valves, reheat steam intercept and stop valves, or extraction steam non-return valves that might lead to an overspeed condition above the design overspeed will be detected. The inservice inspection program for governor and overspeed protection systems operability should include, as a minimum, the following provisions:

1. For typical turbine governor and overspeed protection systems, at approximately 3 year intervals, during refueling or maintenance shutdowns, at least one main steam control valve, one main steam stop valve, one reheat intercept valve and one reheat stop valve,and one of each type of steam extraction valves are to be dismantled and visual and surface examinations conducted of valve seats, disks, and stems. Valve bushings should be inspected and cleaned, and bore diameters should be checked for proper clearance. If any valve is shown to have hazardous flaws or excessive corrosion or improper clearances, the valve is to be repaired or replaced and all other valves of that type dismantled and inspected.

2. Main steam control and stop valves, reheat intercept and stop valves, and steam extraction non-return valves are to be exercised at least once a week during normal operation by closing each valve and observing directly the valve motion as it moves smoothly to a fully closed position.

3. At least once a month during normal operation each compartment of the electrohydraulic governor system (which modulates control and intercept valves), and the mechanical overspeed trip mechanism and backup electrical overspeed trip (both of which trip the main steam control and stop valves, and reheat intercept and stop valves) are to be tested.

On line test failures of any one of these subsystems require repair or replacement of failed components within 72 hours or the turbine is to be isolated from the steam supply until repairs are completed.

3.5.1.3.2 Evaluation

For Byron Station Unit Nos. 1 and 2, the steam and power conversion system generates steam in a direct cycle PWR and converts it to electric power in a turbine generator manufactured by Westinghouse Corporation. The placement and orientation of the turbine generator is unfavorable with respect to the station reactor buildings; that is, there are safety related targets inside the low trajectory missile strike zone. The turbine is a tandem-compound, type (single shaft) with one double-flow high pressure turbine, three double-flow low pressure turbines, and a rated rotational speed of 1800 rpm.

3.5.1.3.2.1 Destructive Overspeed Failure Prevention

The turbine generator has a turbine control overspeed protection system which is designed to control turbine action under all normal or abnormal conditions and to ensure that a turbine trip from full load will not cause the turbine to overspeed beyond acceptable limits so as to minimize the probability of generating turbine missiles, in accordance with the requirements of GDC 4. The turbine control and overspeed protection system is, therefore, essential to the overall safe operation of the plant.

The Westinghouse turbine is equipped with a Digital Electrohydraulic (DEH) Control System consisting of a solid-state electronic controller and a high-pressure, fire-resistant fluid supply used for control of turbine valve operators. The controller compares signals representing turbine speed and first-stage pressure with reference values initiated by a load demand signal. The controller then puts out a comparison signal which actuates hydraulic control of the main turbine governor and reheat steam interceptor valves, to match generator output to load demand.

The turbine governor valve and reheat steam interceptor valves are preceded by main turbine stop-throttle and reheat steam stop valves, respectively. The principal function of these latter valves is to shut off the steam supply to the turbine in the event of a turbine trip.

The control system for turbine governor valves includes three separate speed sensors mounted on the turbine as follows:

a. mechanical overspeed trip weight (spring-loaded bolt),

b. electromagnetic pickup for DEH main speed control channel,

c. electromagnetic pickup for emergency trip system at turning gear location.

The following signals act upon each of the main turbine valves in case the turbine speed exceeds the specified limit:

A. Main Turbine - Stop Throttle and Reheat Steam Stop Valves

Should the turbine exceed approximately 108% of rated speed, these valves will be tripped closed by both (1) the mechanical overspeed trip weight and (2) a redundant electrical trip from the emergency trip system.

B. Main Steam Control Valves

1. The main speed channel continuously calls for rated speed. When the main power transformer breakers open, the turbine speed tends to rise above rated speed. The DEH system has an anticipatory feature that, upon breaker opening, compares actual speed with rated speed. If actual speed exceeds rated speed with the breaker open, the speed channel calls for closing of the control valves.

2. If the unit carried greater than 30% load and the main breaker opens, the control and interceptor valves will be closed by energizing the overspeed protection controller solenoids, which causes high pressure fluid associated with the control valves to be dumped.

3. The overspeed protective controller calls for fully closed control valves at 103% of rated speed.

4. Should the speed exceed 108% of rated speed, the control valves are tripped closed by both (a) the mechanical overspeed trip weight and (b) a backup electrical trip.

C. Reheat Steam Interceptor Valve

1. If the unit carries greater than 30% load and the generator breaker opens, the control and interceptor valves wll be closed by dumping emergency high pressure oil associated with the interceptor valve.

2. The overspeed protective controller calls for fully closed interceptor valves at 103% of rated speed.

3. Should the speed exceed 108% of rated speed, the interceptor valves are tripped closed by both (1) the mechanical overspeed trip weight and (2) redundant electrical trip from the emergency trip system.

The trip design philosophy is as follows:

a. Close the turbine governor valves on an overspeed condition (103%) to prevent reaching the overspeed trip setting (108%).

b. Actuate the overspeed trip (108%) (one mechanical and one electrical emergency trip) to prevent maximum turbine overspeed from exceeding 120%.

According to the applicant's inservice inspection and testing program, a schedule of valve inspection at periodic intervals for throttle, governor, reheat stop, and interceptor valves will be implemented after initial turbine startup.

A functional test of the turbine steam inlet valves is performed periodically. These tests are made while the unit is carrying load. The purpose of the tests is to ensure proper operation of throttle, governor, reheat stop, and interceptor valves. These valves are observed during the tests for smoothness of movement.

Westinghouse is in the process of completing an analysis of turbine missile generation probabilities at destructive overspeed which can serve as a basis for evaluating the adequacy of the applicant's overspeed protection system inspection and testing program. When their report is completed and submitted to the NRC, it will be reviewed and evaluated by the staff. Until then, the NRC alternate criteria, described in Section 3.5.1.3.1.5 of this SER apply to Byron.

3.5.1.3.2.2 Design Speed Failure Prevention

Failures of turbine disks at or below the design speed, nominally, 120 percent of normal operating speed, are caused by a non-ductile material failure at nominal stresses lower than the yield stress of the material. Since 1979, the staff has known of the stress corrosion cracking problems in low pressure rotor disks of Westinghouse turbines. Westinghouse has developed and implemented procedures for inservice volumetric inspection of the bore and keyway areas of low pressure turbine disks. They have also prepared and submitted reports for NRC review which describe their methods for determining turbine disk inspection intervals and relating them to missile generation probabilities due to stress corrosion cracking. These reports are currently under staff review. Until reviews and evaluations are completed the NRC alternate criteria, described in Section 3.5.1.3.1.5 of this SER, apply to Byron.

3.5.1.3.3 Summary

The staff has reviewed the Byron Station with regard to the turbine missile issue and concluded that the probability of unacceptable damage to safety-related structures, systems, and components due to turbine missiles is acceptably low (i.e., less than 10^{-7} per year) provided that the total turbine missile generation probability for each plant is such that conformance with the criteria presented in Table 1 is maintained, throughout the life of the plant, by acceptable inspection and test programs. In reaching this conclusion, the staff has factored into consideration the unfavorable orientation of the turbine generators.

Even if the cracks initiate in the turbine disks at the beginning of service life, it is estimated that they will not grow to a depth of one half the critical crack depth within approximately 3 years of startup. For these reasons, the staff is allowing the applicant up to approximately three years from initiation of power output to propose a revised turbine maintenance program (which

establishes, with NRC approved methods, inspection and testing procedures and schedules) and obtain NRC approval of their program. By letter dated September 26, 1984 the applicant committed to an inspection program based on the manufacturer's recommendations. However, until the staff completes its review, the license is being conditioned to require the applicant to volumetrically inspect all low pressure turbine rotors every third refueling outage. In addition, an acceptable turbine valve inspection program has been incorporated into Section 4.3.4.2 of the Technical Specifications. Thus, License Condition 8 is no longer necessary.

Therefore, the staff concludes that the turbine missile risks for the proposed plant design are in compliance with the requirements of General Design Criterion 4 and are, therefore, acceptable. Thus, Outstanding Item 2 is considered closed.

3.6 Protection Against Effects Associated with the Postulated Rupture of Piping

3.6.2 Determination of Break Locations and Dynamic Effects Associated with the Postulated Rupture of Piping

By letter dated August 16, 1984, the applicant submitted a report entitled "Byron 1 - Confirmation of Design Adequacy for Jet Impingement Effects" dated August 1984 in response to a concern from the Integrated Design Inspection.

In this report, the applicant has referenced NUREG-CR-2913, "Two-Phase Jet Loads" dated January, 1983 as the basis for determining loads due to two phase and steam jets. NUREG-CR 2913 is under review by the staff and several technical community peer groups. Based on a preliminary review of this report, the staff finds the methodology and the general analytical approach acceptable.

The probability of having a full area double ended pipe break (the break required to produce jet impingement loads of the type under discussion) during a short period of time, approximately two months anticipated for low power testing, is considered low. Also the consequences of a pipe break are considered to be less severe at low power than at operation at higher power levels because of much lower decay heat and smaller fission-product inventory. In the event that additional protection is required to protect against the effects of jet impingement, that protection can be provided after the plant has gone through lower power testing.

In view of the above, the staff believes that operation at power levels up to five percent is acceptable pending the applicant's demonstration of the acceptability of the methodology used to evaluate the jet impingement effects of postulated pipe breaks.

The staff is including a condition to the license that requires, prior to exceeding 5% power operation, that the applicant provide the specific use made of NUREG-CR-2913 by identifying all systems and each of the locations in which it was applied, and demonstrate that the use made of NUREG-CR-2913 meets the FSAR commitment on protection against the effects of postulated pipe breaks, or provide an alternative demonstration to the NRC staff of the acceptability of its methodology.

The staff has determined that an exemption is required from GDC 4 to Appendix A, which requires that structures, systems, and components important to safety be appropriately protected against dynamic effects, including the effects of discharging fluids. Based on the aforementioned low probability of a full area double ended pipe break and the reduced consequences of a pipe break at low power, the staff concludes that the exemption from GDC 4 up to 5% power will not endanger life or property or the common defense and security and is otherwise in the public interest.

3.8 Design of Seismic Category I Structures

3.8.3 Other Seismic Category I Structures

License Condition 2 in the original SER required that all the questions pertaining to the analysis, design and erection of masonry walls, including any modifications resulting from the staff's review, be resolved prior to the beginning of the power operation after the first refueling outage.

Since that time, however, additional information has been obtained from the applicant in letters dated December 5, 1983 and July 16, 1984 which indicates that the walls have been analyzed in compliance with the NRC regulatory requirements contained in SRP Section 3.8.4. Comparison of the maximum calculated stresses to the allowable stresses specified in the SRP indicates that the calculated stresses are below the allowables. Further, the applicant provided a summary of results of tests performed on walls similar to those at the Byron plant to estimate the factor of safety against failure. The test results indicate that the average factor of safety is 5.6 for loads under OBE load combinations and 3.55 under the SSE load combinations.

The applicant surveyed 458 walls and determined that 13 out of the surveyed walls had structural cracks. The cracked walls have been identified and reanalyzed by the applicant to demonstrate that these cracks have no effect on structural integrity of the walls.

In view of the above the staff concludes that the design of masonry walls at the Byron plant is conservative and complies with the staff's acceptance criteria. Therefore, the staff concludes that no additional actions are required regarding the masonry wall issue and considers it resolved.

3.9 Mechanical Systems and Components

3.9.3 ASME Code Class 1, 2 and 3 Components, Component Supports, and Core Support Structures

3.9.3.3 Design and Installation of Pressure Relief Devices

As required by NUREG-0737, Item II.D.1, all PWR plant licensees and applicants are required to demonstrate that their pressurizer safety valves (SV), power operated relief valves (PORVs), PORV block valves, and all associated discharge piping will function adequately under conditions predicted for design basis transients and accidents. In response to this requirement, the Electric Power Research Institute (EPRI), on behalf of the PWR Owners Group, has completed a full scale valve testing program and the Owners Group has submitted these test

results to the NRC. Additionally, each PWR plant applicant for an OL was required to submit a report by fuel load which would demonstrate the operability of these valves and the associated piping.

Commonwealth Edison responded to this requirement with submittals dated July 1, 1982 and October 26, 1982 that contain information from the EPRI valve test program results which apply to Byron 1 and 2. A December 30, 1983 submittal also states that the safety and relief valve discharge piping and supports are being modified to insure functionability.

The staff has not completed a detailed review of the applicant's submittals; however, based on a preliminary review the staff finds that the general approach of using the EPRI test results to demonstrate operability of the safety valves, PORVs and PORV block valves is acceptable. The applicant's submittals note that Byron utilizes safety valves, PORVs and PORV block valves similar to valves that performed satisfactorily for test sequences that bound conditions that the valve could be exposed to.

In summary, based on preliminary review, the staff has concluded that the applicant's general approach to responding to this item is acceptable and provides adequate assurance that the Byron Reactor Coolant System Overpressure Protection Systems can adequately perform their intended functions. If the completion of the detailed review reveals that modifications or adjustments to safety valves, PORVs, PORV block valves, or associated piping are needed to assure that all intended design margins are present, the staff will require that the applicant make appropriate modifications.

3.9.3.4 Component Supports

The upper lateral support of the steam generators as described in FSAR Section 3.9.3.4.1.3 consists of two hydraulic snubbers on each of the four steam generators. The original snubbers were manufactured by Boeing and were in place during hot functional testing of Byron 1. At the request of the staff, the applicant had additional qualification testing conducted on snubbers that were identical to the snubbers installed at Byron 1. The testing was conducted by ITT Grinnell in June 1984. The test results were unacceptable and indicated deficiencies in the snubber design. Consequently, the applicant procured snubbers of a staff approved design manufactured by Paul Munroe. The applicant removed the original Boeing snubbers and will replace them with Paul Munroe snubbers. Since the Technical Specifications (3.7.8 and 3.4.5) do not require these snubbers to be operable prior to entering Mode 4, the staff has concluded that the above steam generator snubber replacement program is acceptable.

The staff has determined that an exemption is required from GDC 2 to Appendix A, which requires that structures, systems, and components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. The staff concludes that the exemption from the requirement of GDC 2 prior to entering Mode 4 will not endanger life or property or the common defense and security and is otherwise in the public interest. The staff reaches this conclusion because, prior to Mode 4, (1) the Technical Specifications do not require these snubbers, (2) the steam generators are not needed for decay heat removal, and (3) postulated reactor coolant system pipe break would not produce any offsite doses.

3.9.6 Inservice Testing of Pumps and Valves

To ensure that all ASME Code Class 1, 2 and 3 safety-related pumps and valves will be in a state of operational readiness to perform necessary safety functions throughout the life of the plant, a test program will be conducted which includes baseline preservice testing and periodic inservice testing. The program provides for both functional testing of the components in the operating state and for visual inspection for leaks and other signs of distress.

The applicant, in its November 4, 1982 letter, has stated that the inservice testing programs for the above mentioned pumps and valves will meet the requirements of 10 CFR 50.55a(g), including the 1980 Edition of the ASME Boiler and Pressure Vessel Code, Section XI through the Winter 1980 Addenda. The applicant has requested relief from these code requirements pursuant to 10 CFR 50.55a(g)(5)(iii) for certain pump and valve tests.

The staff has not completed its detailed review of the applicant's submittal. However, the staff has evaluated the applicant's requests for relief and finds that it is impractical within the limitations of design, geometry, and accessibility for the applicant to meet certain of the ASME Code requirements. Imposition of those requirements would, in the staff's view, result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. Therefore, pursuant to 10 CFR 50.55a(g)(6)(i), the relief that the applicant has requested from the pump and valve testing requirements of the 1980 Edition of ASME Section XI through Winter 1980 Addenda should be granted for a period of no longer than 2 years from the date of issuance of the Operating License or until the detailed review has been completed, whichever comes first. If completion of the review results in additional testing requirements, the applicant will be required to comply with them.

3.10 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

3.10.1 Seismic and Dynamic Qualification

The staff's evaluation of the applicant's program for qualification of safety-related electrical and mechanical equipment for seismic and dynamic loads consists of: (1) a determination of the acceptability of the procedures used, standards followed, and the completeness of the program in general, and (2) an audit of the selected equipment items to develop the basis for the staff judgement on the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program. The Seismic Qualification Review Team (SQRT) consists of engineers from the Equipment Qualification Branch (EQB) and the Brookhaven National Laboratory (BNL). The SQRT has reviewed the equipment dynamic qualification information contained in the pertinent Final Safety Analysis Report (FSAR) Sections 3.9.2, 3.9.3 and 3.10 and has made two plant site audits to determine the extent to which the qualification of equipment, as installed at Byron 1, meets the current licensing criteria as described in Regulatory Guides 1.100 and 1.92, Standard Review Plan (SRP) Section 3.10, and Institute of Electrical and Electronics Engineers' IEEE 344-1975 standards. Conformance with these criteria are required to satisfy the applicable portions of the General Design Criteria in 1, 2, 4, 14, and 30 of Appendix A to 10 CFR Part 50, as well as, Appendix B to CFR Part 50 and Appendix A to 10 CFR Part 100.

Discussion on SQRT Review

The SQRT conducted a plant site audit at Byron 1 Nuclear Station on September 13 to September 17, 1982. At the end of the audit, the SQRT concluded that the extent of completion of the applicant's qualification program to be insufficient for SQRT to draw any conclusions with regard to the acceptability of the seismic qualification of all the safety-related equipment. The SQRT also informed the applicant that the review team will conduct a second audit when the program is near completion (see the April 4, 1983 trip report of the first site audit).

On May 13, 1983, a meeting between the staff and the applicant was held in Bethesda, in which the applicant provided a preliminary response to both the generic as well as equipment specific concerns as identified by the SQRT during the above site audit. As a follow-up, the applicant subsequently provided its formal response in a submittal of July 7, 1983.

The SQRT reviewed the information presented by the applicant in the May 13, 1984 meeting and in the July 7, 1983 submittal and determined that the information was still insufficient for the SQRT to conclude the adequacy of the applicant's equipment seismic qualification program. Specifically, a number of equipment items which had not been given favorable review during the above audit were still in the process of being qualified. The staff, therefore, advised the applicant that the need of a second site audit remained.

The second site audit was conducted on November 7 to November 9, 1983. The purpose of the audit is two-fold: (1) to review the applicant's proposed resolution to the open items identified during the first site audit, and (2) to review the overall completeness of the equipment seismic qualification program. During this audit, the SQRT reviewed a list of 12 equipment items which were not fully qualified to the SQRT requirements at the time of the first site audit. This list includes 7 BOP items and 5 NSSS items, and consists of both mechanical and electrical equipment. To be assured of the readiness of equipment documents upon request, the SQRT further selected two (2) additional equipment items at the site for review.

The second site audit revealed that the applicant's equipment seismic qualification program had been significantly improved since the first audit. For the 14 equipment items audited, the SQRT found their qualification to be acceptable with the exception of certain equipment details which would need to be further clarified by the applicant. The only generic concern that remained to be resolved by the applicant was the surveillance and maintenance program for equipment located in mild environment.

The applicant subsequently submitted a post-audit response addressing the above SQRT concerns. Further review indicated that the above generic as well as the equipment-specific concerns have all been satisfactorily resolved by the applicant, with the exception of the auxiliary feedwater pump and drives for which the qualification was not completed. The SQRT reviewed the qualification plan of this equipment during the second audit and found it to be acceptable.

Justification for Interim Operation

Only one category of equipment, the Westinghouse 7300 Process Protection System (ESE-13), for both NSSS and BOP applications, for which qualification is not expected to be fully completed by fuel load was not specifically included among the items reviewed by the SQRT. The applicant has, however, provided justification for interim operation (JIO) in its letters of May 2 and June 19, 1984, which, in the opinion of the staff, justifies the operation until the first refueling outage. The basis of the staff conclusion follows.

(1) ESE-13, Process Protection System, NSSS Application

In a recent seismic and environment test, the NPC, NCH, and NSC cards used in the Process Protection System of the Byron plant exhibited errors which could result in minor changes in system accuracy. The NPC potentiometer card is used as a voltage divider. The NCH (function generator) card is used to develop the actual offset function for overtemperature-delta T set point, whereas NSC (signal converter) card is generally used to convert voltage signal to current signal. These errors are presently under evaluation by Westinghouse to determine the exact effect on the system. The initial Westinghouse evaluation indicates that margins are available to absorb these inaccuracies.

The NTC card exhibited relay contact bounces during the testing. This intermittent signal may cause saturation of downstream RTD amplifier (NRA) cards and could possibly prevent the overtemperature-delta T and overpower-delta T trips from occurring on demand. Since this NTC card, as is currently connected in the system, is used only to ease periodic testing of the channels, bypassing these relays will not affect normal operation of the system. The applicant has issued a field change notice to do such bypassing until a permanent resolution is completed. The staff finds the above interim modification to be acceptable.

(2) ESE-13, Process Protection System, BOP Application

During the seismic shaker table testing, the NTC card used in Byron Station experienced contact bounce. The test response spectra was of a generic nature and much greater in magnitude and broader in peak than the design spectra for Byron/Braidwood. This card operated normally after the event.

The NTD card is used in the main Steam Generator Pressure Relief Control System. Opening and closing control signal path for the power operated relief valves 1MS018A, B, C and D is through the NTD card and relay. During a postulated thirty second seismic event the relay contact experiences random bouncing. Effect of random bouncing is loss of signal whenever the contact is open. Normal signal level is reestablished when the seismic event is over. Since there are five other mechanically actuated relief valves in parallel with each MS018 valve, and since the MS018 valves will be actuated only to establish natural circulation, the potential loss of control signal for thirty seconds will be of no concern to the operation of the plant. This is acceptable to the staff.

The other anomaly that was observed during the testing concerns the NCH card. After four SSE's, one in each of four directions, the NCH had a totalized output shift of 1.02% of output span. Westinghouse states that a shift of this

small magnitude would not constitute failure to qualify especially for the fact that it required four SSE's to cause a shift of this magnitude. Furthermore, the card can easily be brought back to calibration after the seismic event by readjusting potentiometers on the card which is a normal card calibration function. This is acceptable to the staff.

Actions Required for ESE-13 (NSSS & BOP)

Based on the above information provided by the applicant, the staff has determined the applicant's JIO for the Westinghouse 7300 Process Protection System (ESE-13), for both NSSS and BOP applications, to be acceptable for the plant operation up to the first refueling outage, and, at that time, permanent resolutions and all the hardware changes, if deemed necessary, should be completed.

The staff has determined that the ESE-13 equipment requires an exemption from GDC-2 of Appendix A, the requirement that components important to safety be designed to withstand the effects of natural phenomena such as earthquakes. Based on the staff review of the applicant's JIO for the ESE-13 equipment, the staff concludes that the exemption from the requirement of GDC-2 during the first cycle of operation will not endanger life or property or the common defense and security and is otherwise in the public interest.

The final qualification, when completed, should be submitted to the staff for review and acceptance. The permanent resolutions, as proposed, should be based on valid test results, with pre-determined sets of acceptance criteria, in accordance with FSAR commitments and IEEE Standard 344-1975. Any readjustment of design criteria, e.g. contact bouncing, after the testing, in lieu of performing a retest, must be justified.

Summary and License Conditions

Based on the SQRT site audit and the submittals from the applicant, the staff concludes that the applicant's equipment seismic and dynamic qualification program has been satisfactorily defined and implemented according to the current licensing criteria. For the staff to finally approve the program, however, the applicant should take appropriate actions to resolve the remaining open item, and to ensure completion of such actions.

The license is being conditioned to require that the Westinghouse 7300 Process Protection System (ESE-13) be completely qualified, for both NSSS and BOP applications, including all the hardware changes, if found necessary, prior to the end of the first refueling outage. Also, complete qualification documentation should be submitted for the staff review and acceptance.

3.10.2 Operability Qualification of Pumps and Valves

To assure that the applicant has provided an adequate program for qualifying safety-related pumps and valves to operate under normal and accident conditions, the Equipment Qualification Branch (EQB) performs a two-step review. The first step is a review of Section 3.9.3.2 of the FSAR for the description of the applicant's pump and valve operability assurance program. This information is compared to Section 3.10 of the Standard Review Plan. The information

provided in the FSAR, however, is general in nature and not sufficient by itself to provide confidence in the adequacy of the licensee's overall program for pump and valve operability qualification. To provide this confidence, the Pump and Valve Operability Review Team (PVORT), in addition to reviewing the FSAR, conducts an on-site audit of a small representative sample of safety-related pumps and valves and supporting documentation.

The on-site audit includes a plant inspection of the as-built configuration, a discussion of the normal, accident and post-accident conditions under which the equipment and systems must operate, and review of the qualification documentation (status reports, test reports, specifications, etc.).

The two-step review is performed to determine the extent to which the qualification of equipment, as installed, meets the current licensing criteria as described in Standard Review Plan 3.10. Conformance with these criteria provides an acceptable way of meeting the applicable portions of General Criteria 1, 2, 4, 14 and 30 of Appendix A to 10 CFR 50, as well as Appendix B to 10 CFR Part 50.

Background of Previous Audits

Two on-site audits for the Byron Nuclear Station Unit 1 were performed; one during September 9-13, 1982 and a reaudit during November 7-8, 1983. During the audits, a walkdown was conducted to observe the as-built configuration of the selected equipment. Whenever possible, the plant engineers described the features and operating procedures unique to the equipment. A representative sample of three pumps and seven valves was initially chosen for the September 1982 review. However, two items were dropped due to time constraints. The November 1983 reaudit selected one pump and one valve.

During the first PVORT review audit (September 1982), a number of generic and specific concerns were raised which were not satisfactorily resolved by the applicant. This was particularly evidenced in the three "surprise items" for which the applicant only had a few days advance notice in preparation for the audit. These generic and specific concerns and their current status are evaluated in this report under "Discussion" and "Specific Concerns," respectively.

The November 1983 reaudit, conducted at the Byron Unit 1 site, was a follow-up review of the applicant's pump and valve operability program, and was initiated to primarily evaluate document retrieval and central file completeness. This review evidenced a marked improvement in the areas of generic concerns, especially in the traceability of documentation, its approval stamps/signatures, and its timely retrieval. Additional supporting information was supplied by Commonwealth Edison Co. (CECo) during July 1983 and December 1983.

General Discussion

During the September 1982 audit, the utility staff briefly described their Generating Station Maintenance History Program (GSM) with its reliability-related capability for surfacing of troublesome equipment. The applicant also briefly described their computerized General Surveillance Program (GSP) which initiated in-service surveillance by calendar or usage time intervals. These programs were separate from their spare-parts and supplies program. The

execution of these programs will help to satisfactorily address the staff concerns for the operational status of plant equipment. The November 1983 reaudit along with information submittals has shown the applicant to be satisfactorily addressing these programs. These programs, and their effect on the specific equipment audited, are referred to in the "Specific Concerns" portion of this report, as applicable.

For some equipment the concern of environmental effects on operability could not be resolved. This was because the Byron/Braidwood Environmental Qualification Program was in-process and the environmental qualification documents could not be made available to PVORT at the time of the September 1982 audit. Another concern was that the written preoperational test procedures for some of the equipment were still in process and others arrived late in the audit. The applicant, however, demonstrated overall accountability by committing appropriate personnel to resolve these concerns. This accountability was verified at the reaudit by the marked improvement shown in the general area of documentation retrieval, and by the applicant's information submittals received subsequent to the audits.

During the plant walk-down, the installation of some audited equipment was not 100% complete, i.e., several drain pipes were disconnected and temporary pipe supports were in place. The follow-up observations of the PVORT reaudit staff relative to pump and valve installations was favorable with the only discrepancy being an "N" stamp omission on an installed pump. The applicant has demonstrated overall accountability by committing appropriate personnel to resolve these concerns.

Some equipment was not qualified for operability by testing in the combined fluid dynamic and seismic operability conditions. In an effort to justify this analytical qualification approach, additional information and analysis was requested by the staff for specific areas of equipment concern. Also, several of the audited components were qualified by "similarity" by using previously qualified equipment (similar in design, materials, etc.) as a basis for accepting the qualification of the plant installed equipment. The applicant has submitted additional information and analysis for further staff evaluation. These evaluations are discussed in the "Specific Concerns" portion of the report. For other audited equipment, parts were replaced prior to qualification testing. The applicant was asked to submit a comparative analysis to substantiate the replacement of plant installed parts with similar parts, prior to a qualification test program. The applicant has satisfactorily addressed these concerns in information submittals received subsequent to the audit and reaudit.

The above concerns are explained in further technical detail in the following "Specific Concerns."

Specific Concerns

Resolution of all equipment specific items is discussed below.

1. <u>The Safety Injection Pump - NSSS (Item 1SI01PA) and its Electric Motor Driver (Model - Lifeline D-HSDP)</u>

   a. The staff reviewed the shaft deflection analysis performed by Westinghouse relative to pump shaft and rotor assembly clearances. This analysis, which was not part of the initial analytical determinations, was acceptable. It is determined that the applicant has satisfactorily addressed this concern.

   b. A substitute stator used in the pump/motor qualification was justified by comparing the specific materials of the pump stator and the test unit. These materials were similar.

      Additionally, a letter was submitted (Attachment A21, Item 2, CECo July 1983, response to PVORT and SQRT) which documented the plant specific applicability of the motor stator test. It is determined that the applicant has satisfactorily addressed this concern.

   c. The applicant, in response to a PVORT concern, confirmed that inservice periodic testing of this pump is done in conformance with the requirements of Subsection IWP-3400 of Section XI of the ASME Boiler and Pressure Vessel Code, 1980 edition, through the Winter of the 1980 addenda. It is determined that the applicant has satisfactorily addressed this concern.

   d. The applicant, in response to a PVORT request, has submitted documentation (Environmental Qualification of Mechanical Equipment - Byron/Braidwood Units 1 and 2) for the environmental qualification of the safety injection pump. This equipment was selected as a representative component to demonstrate the design and qualification of critical soft parts. This concern has been satisfactorily addressed.

It is determined that the applicant has satisfactorily addressed all of the concerns, and now has the administrative controls in place to assure the operability qualification requirements for this pump. This item is closed.

2. <u>Diaphragm Valve - Reactor Coolant Pressurizer - NSS - (Item Number 1RY8028) and its Air Actuator (Model No. 32101)</u>

   a. During the audit, it was noted that the static deflection seismic/dynamic functional test plan and report had not yet been approved by Westinghouse for the applicant. The CECo July 1983 data submittal indicated that this report had been reviewed (reference the SQRT equipment item as noted in Attachment A 20, Item 3 of their submittal). The Seismic Qualification Review Team (SQRT) staff has reviewed and accepted the functional test plan approved by Westinghouse. This item is closed.

   b. In response to a PVORT request for documentation supporting the usage of a substitute valve assembly in the qualification testing, the applicant has forwarded a vendor letter certifying the applicability of the qualification test report for this valve. The valve selected represented the worst set of parameters for the particular series of

valves being grouped together. A number of valves were covered by one report: reference SQRT, Attachment A 20, Item 1 for the approved test report (July 1983, CECo submittal). It is determined that the applicant has satisfactorily addressed this concern.

c. It was requested that valve closing times (spring-induced) be established during flow interruption testing of the valve; however, that information was not received. The staff's concern as to the valve closing time under load conditions was not resolved. The applicant stated that the valve is capable of closing within the required 10 seconds, under a 300 psig pressure test, and this pressure is far greater than maximum dynamic flow load.

d. It was noted that although the valve appurtenances (solenoids and limit switches) did undergo exploratory vibration tests, the complete valve-body did not. In response to a staff request, the applicant stated that a static analysis was performed by the valve vendor (ITT Grinnell) to calculate the natural frequency of this valve. The horizontal natural frequences of this valve were found to be below 33 Hz. For this reason, the natural frequency analysis reviewed by the audit team was invalidated. Additional vendor testing has subsequently determined that the operability of the valve is not impaired for accelerations as high as 10 g. Westinghouse has since reanalyzed piping systems for this and similar valves in the Byron plant using flexible valve models. The results indicated that both valve and piping system loads are acceptable from an operability standpoint. The staff finds operability of this valve is adequate based upon the Westinghouse re-analysis and the Seismic Qualification Review Team (SQRT) re-evaluation. Final reports will be issued by ITT Grinnell, as will the finalization of piping-analyses by Westinghouse. This data will be entered on revised SQRT and PVORT forms and submitted to the NRC. This concern is closed.

e. Although combined fluid dynamic and seismic operability testing was not done on this valve, the applicant has completed static deflection tests. These tests involved applying loads equivalent to those expected from the combined conditions at the center of gravity of the assembly extended structure. While in the deflection position, the valve was cycled to assure freedom of motion and cycling time, all at the maximum differential pressure to which the valve is designed. It was determined that these tests and vendor in-shop mechanical tests, along with the analyses performed, have satisfied this concern for valve operability.

f. In response to a request for an explanation of the valve's environmental (aging) program, the applicant has described an overall program developed to insure that aging of mechanical components will not adversely affect the availability of safety-related mechanical equipment. It was determined that this response has satisfactorily addressed this concern.

All the concerns on this item were satisfactorily resolved and this item is closed.

3. Check Valve, Safety Injection System - NSSS (Item Number 1SI8949D)

After auditing the documentation for this valve and questioning the environmental effects it would experience, it was determined that the applicant has demonstrated and provided assurance that this valve can perform its intended function under normal, accident, and post-accident operating conditions. This item is closed.

4. Gate Valve, Main Steam Isolation - BOP (Item Number 1MS001A) and its Air Actuator (DWG Number F-4932)

a. In response to a concern that the valve accumulators' internal pressures could exceed their proof pressure under high temperature ambient accident conditions, the applicant referred to a design specification pressure of 5,000 psi, rather than the 3,750 psi normal pressure. Since the accumulators were purchased as an ASME Section VIII component, the applicant had a vendor certification (ASME "N" stamp) that the accumulators met or exceeded code testing requirements, i.e., 1.5 x design pressure or, a minimum test pressure of 7,500 psi. The applicant has addressed this concern satisfactorily.

b. Specification changes were questioned for the external pressures and temperatures (ambient environment) in the Turbine Safety Room, relative to how this turbine room back pressure might affect solenoid pilot valve/actuator operability. The applicant explained that the initial specification of environmental parameters was too conservative. A specification amendment dated July 7, 1983 and received for staff review on December 29, 1983, indicates that emergency design conditions (maximum duration 1 minute) are 350°F temperature, 100 psig pressure, and 100% humidity. At the time of the audit, there was a predicted maximum peak pressure of 20 psig. This peak pressure occurs in less than 1 second after the line break, and is predicated on turbine room doors and ventilation areas being forced open, thereby rapidly venting the area to about ambient in 5 seconds. The concern about the solenoid pilot valves operability under the elevated pressure of 20 psig is based on a design limitation of the air actuator. The applicant has stated that the actuator air supply must be 59 psig above the environmental turbine room pressure. Since actuator supply pressure can be as low as 80 psig, there is only a 1.0 psig margin of safety available should a design basis double-ended break occur. This small margin is inadequate, especially in light of the questionable pressure rise versus time curve, analytically determined, and predicated on the turbine room doors and ventilation areas blowing open and thereby relieving pressure buildup. The applicant stated in its submittal of September 26, 1984 that the FSAR Section C.3.6 describes the area in question as being a "break exclusion zone." As a result, the scenario postulated regarding ambient pressure on the actuator is not applicable for the valve operability issue. This concern is satisfactorily resolved.

c. In response to a concern as to the valve's ability to close against a full flow load, the applicant has referred to vendor testing and analysis. The vendor provides assurance that the closure time

requirements are met by calculating the force necessary to close the valve against a full flow load and then testing the actuator to assure that adequate closing force was available. Documentation of this testing is retained by the manufacturer. The applicant has satisfactorily addressed this concern.

d. At the audit, the PVORT was unable to verify that the plant installed actuator was identical to the qualified unit. The applicant has confirmed that the actuator qualified by analysis (Model 64324-C) is identical to the model installed. The applicant has satisfactorily addressed this concern.

e. It was requested that the applicant provide confirmation that a vibration analysis was performed for the valve, and that it was acceptable. Additionally, an assessment of the effects of aging and its significance on valve operability was asked for. The applicant, in their July 1983 response, confirmed that although this valve was not vibrationally tested, it was fully qualified by analysis, and this analysis established that the valve is not sensitive to vibration levels predicted in seismic events. Also, the Byron vibration monitoring program would detect any unusually high amplitude vibration during preoperational testing. With respect to the aging effects on the valve, electrical components of the valve assembly were considered in the qualification program for 1E equipment in a harsh environment. Aging of mechanical components are addressed by the maintenance and surveillance programs which will detect age related degradation of mechanical components. This program is an extension of the critical soft parts investigation and tabulation as described for the safety injection pump. The applicant has satisfactorily addressed these concerns.

f. The PVORT concern that a gradual loss of accumulator pressure might fail to initiate the solenoid valves pilot operation was addressed by the applicant in the July 1983 response document. The applicant explained that the two accumulators are independent, and that two independent failures in a safety grade system is a scenario beyond the required plant design basis. Additionally, these accumulator pressures are subject to surveillance. The applicant has satisfactorily addressed this concern.

It is determined that the applicant has satisfactorily addressed all concerns relative to this component. Thus this item is closed.

5. Safety Relief Valve - Main Steam - BOP (Item Number 1MS013A) (Surprise Component)

a. In response to a PVORT inquiry as to the external/internal allowable valve leakage rates, the applicant responded by citing this is not a safety concern since it is on the secondary side of the steam supply system. No external or internal leakage data has been recorded (Reference seismic report EMD003901). Additionally, in a teleconference call on 8/7/84 the applicant stated that any leakage would lower the relief valve setpoint, and would add another conservative

factor in its operation. Also, any leakage would be readily noticeable, and corrective action would be taken if the system operation is affected. The applicant indicated that past history of operation at Commonwealth Edison plants shows that the operability of the safety relief valve is not affected by leakage. This item is closed.

b. The staff requested that a formal acceptance test plan and preoperational test plan be written. A preoperational CECo test document number 2.63.10 had indicated that a future preoperational test plan would be written. The applicant responded in the July 1983 document stating that the Byron Pre-Service and In-service Testing Program for valves included the 1MS013A safety relief valve. Prior to startup and at each refueling outage, the valve setpoint will be verified in accordance with IWV-3510 of ASME Section XI. The applicant has adequately responded to the preoperational test inquiry; however, the acceptance test document is actually a seismic document (Phase 3) with valve operability and qualification determined under vibrational loadings.

c. It was noted that as a consequence of a Phase 1 and 2 seismic investigation of this valve's operability, internal damage resulted and a valve redesign was initiated. The qualification testing of this redesigned valve was identified as Phase 3 and the prototype valve tested in Phase 3 was stated to be the same as the production valve installed in the Byron plant, except as described in Section 4.2.1 of the seismic report EMD003901. The staff requested to review the Phase 3 results in order to determine the difference between the qualification test relief valve and the plant installed equipment. This information, which was submitted on September 26, 1984, has satisfactorily resolved this issue.

d. The omission of aging tests for this valve was questioned with respect to establishing its qualified life. The applicant responded that this valve is all metal and does not have any critical nonmetallic parts subject to aging. Therefore, the establishment of a qualified life as a result of aging is not required for this valve. The applicant has satisfactorily resolved this inquiry.

This valve has satisfied all the requirements for operability assurance. This item is closed.

6. <u>Pump, Essential Service Water - BOP (Item Number 1SX01PA) and its Electrical Motor (Model HHS-DPO)</u>

   a. In response to a staff inquiry of the pump's critical speed and its possible proximity to the pump's operating range, the applicant has stated that the minimal critical speed is 2,611 rpm (pump manufacturer data). When compared to the 880 rpm normal pump operating speed, it was ascertained that the range between these two conditions is adequate for safe pump operation. The applicant has satisfactorily responded to this inquiry.

b. A new PVORT form, properly filled out, has been submitted by the applicant in accordance with a staff request.

c. Test reports/procedures for the initial checkout and operational testing of the pump were requested for review. In the applicant's July 1983 response to open SQRT and PVORT audit items, Section 9.20 of the preoperational test procedure was submitted for staff review. This section adequately outlined the initial pump testing. In addition, it was noted that this pump is included in the Byron Preservice Inspection Testing Program Plan (in accordance with ASME requirements) which includes provisions for monitoring pump vibration, flowrate, discharge pressure and bearing temperature. The applicant has satisfied this concern, and has the documentation and controls in place to assure safe equipment operability.

d. A concern relative to establishing the qualified life and aging of susceptible components was addressed in the applicant's July 1983 submittal. It was noted that the essential service water pumps are normally operating components located in a mild environment, and therefore aging would only be due to normal operation. Also referenced was the maintenance and surveillance programs established at Byron. Preventive maintenance is an important part of this maintenance and surveillance program. It is composed of schedule maintenance procedures where equipment is inspected, monitored, serviced, and replaced at required intervals to assure no serious equipment malfunctions occur as a consequence of aging for the life of the plant (Reference SQRT Draft SER - Generic Item 6). The applicant has satisfactorily addressed this concern.

e. The coupling connecting the pump and motor was an area of concern and confirmation of a seismic analysis was requested. The applicant responded that this analysis was done as part of the qualification document (Reference 6.2 of McDonald Engineering Analysis Company Report Number ME-523), which demonstrated the functional capability of the pump. The applicant has satisfactorily addressed this concern.

The staff finds that the applicant has demonstrated and provided assurance that this pump can perform its intended function under normal, accident, and post-accident operating conditions. This item is closed.

7. <u>Pump, Containment Spray - BOP (Item Number 1CS01PA) and its Electric Motor (Model Number VSW-1 (Surprise Component)</u>

a. In response to a concern relating to an in-plant pump replacement that was not properly documented, the applicant has verified that all qualification documentation pertaining to this equipment change has been corrected, approved, and signed off. The applicant has satisfactorily addressed this concern.

b. At the audit, the PVORT was unable to confirm that a program existed which would enable in-service pump testing results to be correlated with preoperational/shop testing data, the purpose being to monitor the unit for possible performance degeneration. The applicant, in

his July 1983 response to the SQRT and PVORT audit report, has submitted a section of the preoperational test results for the pump with its corresponding acceptance test criteria. Additionally, attention was drawn to the Byron pre-service/in-service testing program plan for pumps, which includes this pump. This program has been developed in accordance with ASME Section XI requirements, i.e., it includes provisions for monitoring vibration, flowrate, and discharge pressure. This data, when compared to the preoperational/acceptance test parameters, will demonstrate the operability of the pump. The applicant has satisfactorily addressed this concern.

c. The staff was unable to confirm, at the time of the audit, whether the determination of the 40-year qualified life for this equipment fully considered the environmental and dynamic conditions it would be subject to. The applicant responded to this concern (July 1983 submittal) by referencing a pump motor environmental/seismic qualification report by Westinghouse, Number WCAP-8754, Revision 1 and Shop Order 77F14089, and a pump seismic qualification report by Ingersoll-Rand. Also submitted by the applicant was an environmental qualification of containment spray pumps by Sargent and Lundy, dated February 25, 1983. Since there was no previous environmental qualification, this analysis investigated various sources of information relative to non-metallic components used in the pump, i.e., number 5 carbon and ethylene propylene terpolyner "O" rings. The investigation disclosed that the anticipated radiation, corrosion, temperature, humidity, and pressure environments would not degrade the 40-year life expectancy of the pump, as long as proper maintenance and inspections are carried out in accordance with vendors recommended manuals and ASME Section XI, Division 1, Article IWP-1000 (10 CFR 50). It is found that the information above, along with the applicants maintenance and surveillance programs, have satisfactorily addressed this concern.

The applicant has demonstrated and provided assurance that this pump can perform its intended function under normal, accident, and post-accident operating conditions. This item is closed.

8. <u>Butterfly Valve-Essential Service Water - BOP (Item Number 1SX027A) and its Actuator (Model Number SMB-00/7.5 H1BC)</u>

a. A revised PVORT form was resubmitted by the applicant with the omissions from the earlier submittal filled in, e.g., the correct valve mounting method and maximum operating torque required. The applicant has satisfactorily responded to this data omission.

b. It was observed that the valve specification (F/L-2884) submitted for review did not specifically cover this 16-inch valve, although it did cover 12-, 24-, 36-, and 48-inch valves. The applicant's response to this omission indicated that indeed, although not obviously listed, the subject valve was covered under the F/L-2884 specification indirectly. This valve was procured via purchase order 83068 which references data sheet D5004, Revision 1 and thereby specification F/L-2884. This purchase order and data sheet were part of the appli-

cant's response. Therefore, the specification will not require revision, and the applicant has satisfactorily responded to this concern.

c. Verification was requested of a proper valve installation relative to the manufacturer's recommendation for flow direction through the valve. In response (July 1983), the applicant said the valve is marked with an arrow to indicate the preferred installation direction, but that installation direction is independent of flow direction, i.e., the valve will close against flow in either direction. The arrow indicates the preferred direction for sealing against flow. A field check was made which verified that in its installed position, this valve will seal against flow when used to isolate containment. Containment isolation is the primary concern, and therefore the applicant has satisfactorily answered this verification request.

d. The completeness of test documentation such as exploratory vibration and preoperational testing was not verified at the time of the audit. The applicant, in response to this PVORT concern (July 1983 response), has verified that this valve's seismic qualification report (Jamesbury Corporation Report JCS82-02, Revision 2) had been received, reviewed, and approved. The Limitorque valve operator had been qualified by test (Limitorque generic qualification report). This valve is included in the Byron pre-service and in-service test program (reference page 43 of this program report, submitted on November 4, 1982). The applicant has satisfactorily addressed this concern.

e. Concerns relative to the valve torque requirement versus Limitorque actuator torque output were raised at the audit. The applicant, in its July 1983 response document, submitted a memo of a telecon (June 1983) between Limitorque Corporation and Sargent and Lundy on this subject. The valve operating torque of 1,180 ft-lbs was compared to the available operator torque of 1,250 ft-lbs nominal and 1,300 ft-lbs maximum at 100% voltage requirement. Sargent and Lundy found the actuator adequate for valve operation. Concern about the small margin of safety from the nominal actuator torque (1.05%), if the voltage requirement for the Limitorque actuator has an acceptable voltage below 100% was addressed in the September 26, 1984 submittal. This submittal indicated that the operator is capable of closing the valve within the specified time at maximum design differential pressure at the rated voltage of ±10%. The operator will deliver full running torque, not seating torque, without damage when the voltage drops to 75% of rated voltage.

f. The qualified life of this valve became a concern during the audit. This concern was not fully addressed, but was responded to by the applicant in their July 1983 response to SQRT and PVORT audit concerns. The applicant stated that the valve actuator had been environmentally qualified in the generic Limitorque qualification program, but that an environmental qualification of the valve itself is not required. The only non-metallic parts in the valve are the valve seat (EPT-ethylene propylene terpolyner) and the valve packing (John Crane 187-I).

This valve is included in the in-service testing program and the containment isolation valve leak rate testing program; therefore, any degradation of the valve which could affect its ability to isolate the containment will be detected by testing and surveillance. Additionally, the September 26, 1984 submittal states that the critical soft parts on this valve (listed below) have been qualified for 40 years at the specified environmental conditions of 320°F (3 minutes), 100 psig and $2x10^8$ RADS.

Valve Seat: E.P.T.; Shaft Bearing: Fiberglass Expoxy, Nylon; Shaft Seal: John Crane 187 (Asbestos-Graphite)

Ordinary maintenance and surveillance will ensure scheduled changeout of parts that may degrade due to normal mechanics of wear. This valve has satisfied all requirements for operability assurance. This item is closed.

9. <u>Relief Valve - RHR Pump Suction - NSSS (Item Number 1RH8708B)</u>

a. At the November 1983 plant walkdown, the PVORT noted that the original valve to be reviewed (1RH8708<u>A</u>) had been replaced by the 1RH8708<u>B</u> valve which was audited. Documentation of the acceptability of piping system accelerations and nozzle loads of the '<u>B</u>' valve were submitted and reviewed (reference Westinghouse memo MID-PUE-2059 dated December 13, 1983). Also submitted at this time was a document from the RHR system design team which indicated that the stresses predicted for this valve in the seismic analysis are not adversely affected by the fact that the valve discharges into a closed system. The applicant has satisfactorily addressed these concerns.

b. In response to a staff inquiry, a revised table of "Active Valves" (FSAR Table 3.9-16) which deletes both the 1RH8708A and B valves was submitted. This was done because the applicant disclosed that these valves are not required to shut down the plant or mitigate the consequences of an accident. This item is considered closed since the 9/26/84 submittal confirmed that the valve is not a safety-related item.

10. <u>Pump Auxiliary Feedwater - BOP (Item Number 1AFO-1PB-1) and its Diesel Driver (Model 16V-14971'"V")</u>

a. At the November 1983 audit the PVORT noted that the diesel drive for this pump was undergoing qualification tests at Southwest Laboratories under the auspices of the owners group.

b. Although all of the pump documents reviewed bore stamps indicating review and approval by the A & E (Sargent and Lundy) it was noted during the plant walkdown that the pump ASME "N" stamp could not be located. There were "N" stamps at the nameplates of the heat exchangers associated with this pump, but none were found on the nameplate of the pump itself. Verification of the pump "N" stamp requirement and stamping was submitted and approved by the NRC previously. This item is considered closed.

This pump has satisfied all the requirements for operability assurance. This item is closed.

Conclusion

Based on the results of the site reviews performed at Byron 1 (September 13-17, 1982 and November 7-8, 1983), and the subsequent submittals by the applicant to resolve issues identified from the site reviews, it has been concluded that a marked improvement in plant pump and valve operability qualification has been achieved by the licensee.

Staff concludes that an appropriate pump and valve operability qualification program has been established. The continuous implementation of this overall program should provide adequate assurance that the safety-related functions will be performed as needed.

3.11 Environmental Qualification of Electric Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

Equipment which is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement, which is embodied in General Design Criteria 1 and 4 of Appendix A, and Sections III, XI, and XVII of Appendix B to 10 CFR 50, is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants;" NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements IEEE Standard 323; and various NRC Regulatory Guides and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews. The positions contained in this report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods which are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC requested certain near term Operating License (OL) applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs comply with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements

for operating reactors. This bulletin and its supplements were provided to OL applicants for consideration in their review.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, Section 50.49 of 10 CFR Part 50, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In accordance with 10 CFR 50.49, electrical equipment in the Byron Station may be qualified in accordance with the acceptance criteria specified in Category 1 of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A & B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

In order to document the degree to which its environmental qualification program complies with the NRC's environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated June 17, 1982; January 14, 1983; April 14, 1983; May 6, 1983; December 6 and 30, 1983; April 23, July 3 and September 10, 18 and 27, 1984 and October 18, 1984 to supplement the information contained in Section 3.11 of the FSAR.

3.11.2.1 Purpose

The purpose of this SER is to evaluate the adequacy of the Byron environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and for safety-related mechanical equipment. The staff position relating to open items, as well as any unresolved issues, is provided in this report.

3.11.2.2 Scope

The scope of this report includes an evaluation of the completeness of the list of systems and equipment to be qualified, the environments in which they must function, and an assessment of the qualification documentation for equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

3.11.3 Staff Evaluation

The staff evaluation of the applicant's environmental qualification program included an onsite examination of equipment, audits of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria described in NUREG-0800, Section 3.11, Rev. 2, NUREG-0588 Category I, and 10 CFR 50.49 form the bases for the staff evaluation of the adequacy of the applicant's qualification program.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on June 21-23, 1983. The audit consisted of a review of eleven files containing information regarding the equipment

qualification. The staff's findings during the audit are discussed in detail in Section 3.11.4.2.

3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment which are required to be qualified in accordance with the provisions of the rule:

- Safety-related electrical equipment, i.e., equipment relied upon to remain functional during design basis events.

- Nonsafety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment.

- Regulatory Guide 1.97 Rev. 2, Category 1 and 2 post-accident monitoring equipment.

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of DBAs and with components located in a harsh environment were compared to Table 3.2-1 of the FSAR, "Safety Category and Quality Group Classifications for Structures and Components." Omission of systems from the harsh environment program were adequately justified by the applicant (such as all equipment located in a mild environment). Table 3.11-4 lists the systems identified and their Class 1E function.

To address conformance with 10 CFR 50.49(b)(2) concerning non-safety-related equipment whose failure under postulated accident conditions could prevent the satisfactory accomplishment of safety functions, the applicant referred to staff reviews of the responses to IE Information Notice 79-22, "Qualification of Control Systems." In addition, the staff has reviewed and evaluated the applicant's conformance with RG 1.75, "Physical Independence of Electric Systems," and found it acceptable.

On the basis of this, the staff concludes that the applicant's conformance to 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2 instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated that all such equipment is included in the qualification program. However, in addressing conformance with RG 1.97, the applicant has identified a number of exceptions. The staff will determine the acceptability of these exceptions as part of its review for conformance with RG 1.97. This review may result in the addition of equipment to the environmental qualification program.

3.11.3.2 Qualification Methods

3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed procedures for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in this NUREG are also applicable to other equipment important to safety defined in 10 CFR 50.49. Type testing of equipment in a sequence consisting of pre-aging (thermal, radiation, and mechanical), seismic and dynamic loading, and exposure to LOCA/HELB conditions (where applicable) is the principal method of qualification:

3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, General Design Criteria 1, "Quality Standards and Records," and 4, "Environmental and Missile Design Bases;" Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," Sections 3.11, Revision 1 contain the following requirements related to equipment qualification:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with loss-of-coolant accidents.
- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.
- Design control measures shall be established for verifying the adequacy of design.
- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, qualification documentation for three items of safety-related mechanical equipment has been submitted by the applicant and has been reviewed by the staff. The staff review has verified that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed except for three components identified in the applicant's July 3, 1984 letter. The applicant has provided acceptable justification for interim operation (JIO) for two components.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be utilized for determining the environmental conditions associated with loss-of-coolant accidents or high energy line breaks, inside or outside containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the conditions established by the applicant.

3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside Containment

The applicant provided the LOCA/MSLB profiles used for equipment qualification. The peak values resulting from these profiles are as follows:

	Maximum Temperature, °F	Maximum Pressure, psig	Humidity, %
LOCA	265°F	50 psig	100%
MSLB	330°F	38 psig	100%

The staff has reviewed these profiles and finds them acceptable for use in equipment qualification; i.e., there is reasonable assurance that the actual pressures and temperatures will not exceed these profiles anywhere within the specified environmental zone (except in the break zone).

3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside Containment

The applicant has provided the temperature, pressure, and humidity conditions associated with high energy line breaks outside containment. The criteria used to define the size and location of breaks are described in FSAR Section 3.6 and response to Question 010.40. The following areas outside containment are subject to a harsh environment following a high energy line break:

- Auxiliary Building
- Steam Tunnel

Recently the staff has reviewed the methodology submitted by Westinghouse for computing mass and energy releases for postulated main steam line break accidents. This methodology, when applied to plant specific analyses, may predict higher thermal environments than previously prescribed for environmental qualification of safety-related equipment. However, it is the staff's opinion that a main steam line break during operation up to 5% of full power will not result in a more severe environment than currently predicted. Therefore, prior to exceeding 5% of full power operation a justification for interim operation should be provided.

3.11.3.3.3 Submergence

The maximum submergence levels have been established by the applicant for various plant areas. Inside containment, an elevation of 382 feet 2 inches, or approximately five feet above the containment floor, is postulated as a result of transferring the volume of the refueling water storage tank to the containment. Equipment which is required post-LOCA and subject to submergence is or will be qualified for this condition.

The outside containment flooding analysis is discussed in Section 3.6 of the FSAR and the response to Question 010.47. It has been reviewed and evaluated in Section 3.6.1 of Supplement No. 2 to the Byron SER.

3.11.3.3.4 Chemical Spray

Chemical spray may be utilized during an accident for containment heat removal. The applicant has included this parameter in the evaluations of equipment located inside containment.

3.11.3.3.5 Aging

The aging program requirements for Byron electrical equipment are defined in Section 4, Category 1 of NUREG-0588. The degrading influences of temperature, radiation, vibration, and electrical and mechanical stresses should be considered and included in the aging program. Any justifications for excluding pre-aging of equipment in type testing should be established based on equipment design and application, or on state-of-the-art aging techniques. A qualified life is to be established for each equipment item. In addition to the above, a maintenance/surveillance program should be implemented to identify and prevent significant age-related degradation of electrical and mechanical equipment. The applicant has committed to follow the recommendations in Regulatory Guide 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American National Standard ANS-3.2/ANSI N18.1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," in the FSAR. This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include a) utilizing experience with similar equipment, b) revising and updating the program as experience is gained with the equipment during the life of the plant, c) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and d) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate. The applicant has stated that a maintenance/surveillance program is in effect at Byron.

3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values for the radiation levels postulated to exist following a LOCA. The application and methodology employed to determine these values were presented to the applicant in NUREG-0588 and NUREG-0737, "Clarification of TMI Action Plan Requirements." The staff review determined that the values to which equipment was qualified enveloped the requirements identified by the applicant.

The values specified for use in equipment qualification in the containment is an integrated dose of 2×10^8 rads. In the auxiliary building, doses of up to 10^7 rads were used in areas with recirculating fluid lines. These values are acceptable for use in the qualification equipment.

3.11.3.4 Outstanding Equipment

For safety-related items not having complete qualification documentation, the applicant has provided commitments for corrective action and schedules for completion. For items not expected to have full qualification, analyses must be performed in accordance with paragraph (i) of 10 CFR 50.49 to ensure that

the plant can be operated safely pending completion of environmental qualification. These analyses have been submitted for consideration. The staff has reviewed the justification for interim operation and has concluded that reasonable assurance has been provided that the Byron plant can be operated safely pending completion of environmental qualification.

3.11.4 Qualification of Equipment

The following subsections present the staff's assessment of safety-related electrical equipment based on the applicant's submittal, audits of documentation at the plant site, and previous staff evaluations of equipment in other plants.

3.11.4.1 Safety-Related Electrical Equipment

The staff has separated the electrical equipment in a harsh environment into three categories: (1) equipment requiring replacement prior to plant startup, (2) equipment requiring additional qualification information or corrective action, and (3) equipment considered acceptable. An appendix listing equipment in each of these categories is provided.

3.11.4.1.1 Equipment Requiring Replacement Prior to Plant Startup

Table 3.11-1 identifies equipment which the staff review has determined requires replacement prior to plant startup. There is no equipment in this category for the Byron Station.

3.11.4.1.2 Equipment Requiring Additional Information and/or Corrective Action

Table 3.11-2 identifies equipment in this category. Corrective action or deficiencies are noted by a letter relating to the legend identified below.

<u>Legend</u>

A - material-aging evaluation; replacement schedule; ongoing equipment surveillance
AC - accuracy
CS - chemical spray
EXN - exempted equipment justification inadequate
H - humidity
I - HELB evaluation outside containment not completed
M - margin
P - pressure
QI - qualification information being developed
QM - qualification method
QT - qualification time
R - radiation
RPS - equipment relocation or replacement, schedule provided
RTS - retest, schedule provided
S - submergence
SEN - separate effects qualification justification inadequate
T - temperature
AC - accuracy

The deficiencies have been determined on the basis of all the information available to the staff at the time of review and do not necessarily mean that the equipment is unqualified. However, the deficiencies are cause for concern and require further case-by-case evaluation. The applicant has stated that all of the concerns identified have been reviewed and all deficiencies identified have been adequately resolved and are auditable. In accordance with 10 CFR 50.49(i) acceptable justifications for interim operation have been submitted for equipment items not having complete qualification.

3.11.4.1.3 Equipment Considered Acceptable

Based on the staff review, the items identified in Table 3.11-3 have been determined to be acceptable.

3.11.4.2 Environmental Qualification Audit

The staff and EG&G Idaho personnel conducted an audit of the Byron plant qualification files and installed equipment on June 21-23, 1983. The following observations and conclusions and their subsequnt resolutions were made as a result of the audit:

- Not all essential equipment potentially exposed to flooding has been identified. For example, it was observed during the plant walkdown that the junction box for a valve motor operator required to operate post-LOCA was located below the flood level in containment but had not been reviewed for submergence qualification. The applicant must therefore conduct a plant walkdown to identify all equipment and interfaces (junction boxes, splices, etc.) which are below the postulated flood levels and either relocate these items or demonstrate qualification for submergence. The applicant has subsequently informed the staff that all essential equipment have been relocated above flood level.

- In several of the equipment reviews, it was determined that insufficient attention had been given to the acceptance criteria for qualification tests and their applicability to plant specific requirements (see discussions of Marathon terminal blocks and Conax penetrations below). The acceptance criteria for all equipment in the program should therefore be reviewed. The applicant has subsequently reviewed the acceptance criteria for all equipment and has provided the status of all files in their revised submittal.

- A number of discrepancies existed between the qualification summary sheets supplied with the environmental qualification submittal and the information in the plant files, most of which were satisfactorily addressed during the audit. The summary sheets were furnished to the staff on June 17, 1982 and did not reflect the most recent qualification data. The applicant has since provided the revised and updated submittal.

In the review of individual items of equipment during audit, several questions could not be satisfactorily resolved. These are listed below and must be addressed by the applicant prior to licensing.

- Anchor/Darling Main Steam Isolation Valve - the audit team was unable to resolve questions concerning the correct values for postulated pressure and temperature during a DBA, the required operability time, and time period after an accident during which failure may not occur. In addition, the failure modes and effects analysis and identification of valve accessories should be clarified. Since then, the applicant has submitted the revised file for the equipment. The staff has reviewed the file and found it acceptable.

- Marathon 1600 Series terminal blocks - the staff reviewed this item for instrumentation applications. The acceptance criteria specified included only the ability to withstand an applied voltage and current and to not exceed a specified level of leakage current during exposure to LOCA conditions. Insulation resistance values were specified in the design specification but were not measured during LOCA exposure. In addition, the leakage current tests results indicated that insulation resistance, although not directly measured, was probably less than the value required for instrumentation circuits. The applicant stated that the test results can apply to control circuits only and has replaced terminal blocks with splices in this application as a result of the review.

- Conax electrical penetrations - the qualification file did not contain results of insulation resistance measurements during exposure to LOCA conditions, as required by IEEE 317-1976. The checklist in the file did not address this omission and accepted the existing incomplete test data as sufficient. The applicant contacted the vendor during the audit and determined that these data were available and demonstrated the acceptability of the instrumentation penetrations for this application. The applicant has received the information from Conax and incorporated it into the EQ file. The applicant also committed to providing information on surveillance to be used to monitor the condition of the penetrations during the life of the plant. The applicant has since provided the surveillance information to the staff. The staff finds the information acceptable.

- Rosemount 1153B transmitter - the applicant should confirm that the transmitter will be replaced at proper intervals. Since then, the applicant has confirmed the replacement interval, thus resolving the staff's concern.

- Reliance fan motor for RCFC - the comparison of postulated chemical spray conditions versus tested conditions should be furnished to the staff for review. Since then the applicant has provided the analysis to demonstrate that the test condition exceeded the postulated condition. The staff finds the applicant's response acceptable.

- Okonite and Dekorad cables - the applicant committed to provide information on surveillance techniques to be utilized for cables inside containment. The applicant has stated that Byron cables are not susceptible to any significant age related degradation. The existing maintenance and surveillance program will identify any age related problem. The staff finds the applicant's response acceptable.

3.11.5 Conclusions

The staff has reviewed and evaluated the Byron Station program for the environmental qualification of electrical and mechanical equipment. This review has been performed to assure that the systems selected for qualification, the environmental conditions resulting from design basis accidents, and the methods used for qualification are in compliance with applicable regulations and standards.

The following License Conditions should be incorporated into the Byron Unit 1 License:

(1) Prior to exceeding 5% of full power operation, the licensee shall provide justification for interim operation regarding the issue of steam superheat caused by high energy line break outside containment. Final resolution of this issue shall be based on the Westinghouse Owners Group findings.

(2) All electrical equipment within the scope of 10 CFR 50.49 must be environmentally qualified by November 30, 1985.

Based on the results of our review and evaluation, and upon satisfactory completion of the confirmatory item identified above, we conclude that the applicant's environmental qualification program is acceptable and that adequate justification has been provided to authorize operation up to 5% of full power. Therefore, pending resolution of License Conditions (1) and (2), the staff concludes that the applicant has demonstrated conformance with the requirements for environmental qualification as detailed in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections III, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria specified in NUREG-0588.

Table 3.11-1

EQUIPMENT REQUIRING REPLACEMENT
PRIOR TO PLANT STARTUP
(SECTION 3.11.4)

No equipment in this category

Table 3.11-2

EQUIPMENT REQUIRING ADDITIONAL INFORMATION OR CORRECTIVE ACTION (SECTION 3.11.4.1.2)

Component	Manufacturer	Model Number	Deficiency/ Corrective Action
Valve Operator (1CC 9416 9413 A/B, 9414)	Limitorque	SMB 0010	Replace
Containment Purge Valve Operators	Borg-Warner	85450/84560	QI
Pressure Switches	United Electric	J302-S164	QI
Main Steam Atmospheric Relief Valve Operators	Borg-Warner	85280	QI
Differential Pressure Switch (1LS-CS 046A/046B)	Barton	288A	Replace
Incore Thermocouples, Connectors, Adapters	Westinghouse	--	QI
Inadequate Core Cooling Instrumentation	CE	--	QI
Differential Pressure Indicating Switches (1RH-610/611)	Barton	288A	Replace
Flow Indicating Switches (1FIS-CC063/064)	Barton	288A	Replace

Table 3.11-3

EQUIPMENT CONSIDERED ACCEPTABLE
(SECTION 3.11.4.1.3)

Component	Manufacturer	Model No.
Limit Switch	Namco	EA180
Limit Switch (O/C)	NAMCO	EA170
Solenoid Operated Valve	ASCO	NP Series
Electrical Penetration	Conax	-
Pump Motor	Westinghouse	Frame 5809P, Type LLD
Junction Box	Connectron	NU-2
Pump Motor	Westinghouse	HSDP, VSW1
HVAC Supply Fan Motor	Reliance	Type RB1
Ventilation Fan	Reliance	Type RH
Cooler Fan Motor	Westinghouse	3HP, Class H
RCFC Fan Motor	Reliance	600287-52, FR 5008
Instrument Cables	Samuel Moore	1900 Series
Power Cable	Okonite	Okonite EPR
Electrical Penetration	Bunker Ramo	-
Motor Operator	Limitorque	SMB/SMD/SB
Damper Motor Actuator	ITT General	NH91, NH95
Hydraulic Operator (FW)	Borg Warner	P/N - 38971
Hydraulic Operator (MS)	Anchor/Darling	S/N E-6105
Indicator Light	Westinghouse	EZC
Flow Transmitter	Rosemount	1153 DB8
Selector Switch	Westinghouse	OT2
Temperature Switch	United Electric	C303D-103
1-plex Wire	GE	SIS
Terminal Block (O/C)	GE	CR151B2-NUC
Flow Indicating SW	ITT Barton	581A
High Range Radiation Detector	General Atomic	RD-23
Pressure Switch	BSE	BIT-A48SS
Coax. Cable	Rockbestos	RSS-6-104/109/113
Switch Board Wire	Rockbestos	RSS-400-2
Radiation Detector	General Atomics	RD-10B,RD-8
RTD	Conax	PN 7D78-10000-01
Transmitter	Barton	752/753/764/763
AR - Relay	Westinghouse	AR 440/660/880
Fuse Pullout	Gould - ITE	P-302-C
Junction Box	Borg Warner	-
Pressure Transmitter	Veritrak	76PH-2, 76DP2
RTD	RdF	21204, 21205
Pressure Sensor	Barton	351
Motor Control Center	Westinghouse	Five Star
Neutron Detector	Westinghouse	W/L-24159, 23753
Electrical Seal Assy	Litton/Conax	CIR/N11007
Terminal Block	Marathon	1600
Hydrogen Recombiner	Rockwell International	-

Table 3.11-4

SAFETY RELATED SYSTEMS AND FUNCTIONS
(SECTION 3.11.3.1)

Function	Systems
1. Emergency Reactor Shutdown	Auxiliary Feedwater Chemical and Volume Control Residual Heat Removal Safety Injection Reactor Protection Control Rod Drive
2. Containment Isolation	Reactor Protection Fire Protection and Detection Main Feedwater Main Steam Process Sampling Reactor Building, Containment Equipment Reactor Building, Containment Floor Service Air Steam Generator Blowdown Station Heating Reactor Coolant Pressurizer
3. Reactor Core Cooling	Auxiliary Feedwater Chemical and Volume Control Safety Injection
4. Containment Heat Removal	Containment Spray Residual Heat Removal HVAC Systems
5. Core Residual Heat Removal	Residual Heat Removal
6. Prevention of Significant Release of Radioactive Material to Environment	Containment Spray Hydrogen Recombiner HVAC Systems Process Radiation Monitoring Communication Incore Flux Mapping Low Voltage
7. Support Systems	Auxiliary Feedwater Component Cooling Giesel Generator Diesel Oil Essential Service Water HVAC Systems Chilled Water Auxiliary Power Process Radiation Monitoring Area Radiation Monitoring Battery and D-C Distribution Instrument and Control Power Neutron Monitoring Reactor Cooling

4 REACTOR

4.4 Thermal and Hyraulic Design

4.4.1 Departure from Nucleate Boiling Methodology

In the original SER, the staff stated that the thermal-hydraulic design methodology using the Westinghouse improved thermal design procedure (ITDP) is acceptable; however, the acceptability of the Byron design DNBR limit required further plant-specific review regarding the uncertainties, variances and distributions of the pertinent parameters used in the ITDP. This SER supplement addresses the staff findings resulting from the Byron plant-specific review.

The applicant, by letter dated May 5, 1982, submitted a Westinghouse response to a staff question regarding the ITDP parameter uncertainty distributions and their effects on the design DNBR limit. This response also references a Westinghouse generic report which provides a detailed breakdown of the instrumentation error components and a description of the statistical method used in combining these instrumentation errors to determine the measurement uncertainties of the pertinent ITDP parameters such as pressurizer pressure, reactor coolant temperature, RCS flow rate and reactor power. The error components in a measurement channel are combined statistically if they are independent. Error components which are not independent are added arithmetically into groups, and the independent groups are then combined statistically. This method of calculating the measurement uncertainties has been previously found acceptable. The instrument uncertainty values assigned to the Westinghouse report are a conservative bounding set of instrument uncertainties for standard Westinghouse instruments. These values have been reviewed previously for V. C. Summer Nuclear Station, Unit No. 1 in NUREG-0717, Supplement No. 4. Attachment 1 to the May 5, 1982 letter indicated that the Byron uncertainties for pressurizer pressure and core coolant temperature are identical to the Westinghouse generic values since the sensors, process racks, and computer and readout devices are standard Westinghouse supplied NSSS equipment. Therefore the measurement uncertainties for the pressurizer pressure and reactor coolant temperature are acceptable.

The reactor power is measured periodically by a secondary side power calorimetric, i.e, the reactor power is the product of the feedwater flow rate and the enthalpy rise across the steam generator. Only the feedwater pressure and temperature are measured with non-Westinghouse supplied instruments. The error allowance for these instruments vary slightly from the Westinghouse generic value. In the feedwater flow measurement, the uncertainty associated with crud buildup in the feedwater venturi is not taken into account. However, since venturi fouling would result in higher measured feedwater flow and higher indicated value of reactor power, neglecting venturi fouling for power measurement is acceptable.

The RCS flow is measured periodically with the elbow taps in the cold legs to verify that the RCS flow does not violate the acceptable limit during power operation. The elbow tap flow measurements are normalized against a precision

flow calorimetric measurement which will be performed at the beginning of each fuel cycle. Therefore, the overall uncertainty of the RCS flow measurement consists of the uncertainties associated with the precision flow calorimetric and the elbow tap flow measurements.

In the determination of the flow calorimetric uncertainty, several interdependent error components are combined statistically, and thus violate the independence requirement. For example, the venturi thermal expansion factor, feedwater density and enthalpy are all dependent upon the feedwater temperature; the feedwater density and steam enthalpy are both dependent on steam line pressure because the feedwater pressure is calculated from the steam line pressure; and the hot leg and cold leg enthalpies are both dependent on the pressurizer pressure. However they are treated as independent quantities because the magnitude of the uncertainties of these interdependent error components are so small compared to the dominant error components, such as the hot leg temperature stratification uncertainty, that the use of the statistical treatment of these components has no significant effect on the final result. In a letter dated August 13, 1984, the applicant provided several examples treating these interdependent error components both statistically and deterministically to demonstrate the minimal effect on the final results. In addition, the uncertainty values used in the analysis are the bounding conservative values which can offset the small error resulting from the statistical treatment of these interdependent error components. Therefore, the statistical treatment of these error components is acceptable.

Drift effect of the measurement instrumentation is not included in the analysis except where necessary due to sensor location. The applicant indicates that the Byron plant procedures will include provisions to ensure that the performance of calorimetric RCS flow measurement will require calibrations within seven days of the flow measurement for instruments used in determining the RCS flow. Therefore, neglecting the drift effect in the error analysis is acceptable. The requirement of the calibration of the calorimetric flow measurement instrumentation has been incorporated in the Technical Specifications.

The fouling effect due to crud buildup in the venturi is not taken into account in the feedwater flow measurement. Since the venturi fouling is a bias which will result in a higher measured feedwater flow as well as RCS flow than the actual values, neglecting venturi fouling effect on RCS flow measurement is not acceptable. However, the Byron Technical Specification has included a provision of 0.1% error to be added to the overall RCS flow error to account for the RCS flow measurement error due to venturi fouling. The applicant has indicated that the venturis will be cleaned at the start of the first cycle when the precision secondary plant calorimetric measurements will be performed. Therefore, negligible uncertainty will be introduced into the RCS flow calculation for the first cycle and the 0.1 percent error provision is appropriate. The applicant has also committed to institute, prior to full power operation, a monitoring and trending program that will be performed to detect venturi fouling. If venturi fouling is detected, the venturi will be cleaned prior to the performance of the flow calorimetric measurement or the degree of fouling will be assessed and included as a penalty on determining the RCS flow. If it is determined that the trending program is not capable of detecting 0.1 percent venturi fouling, the Technical Specification will be modified to provide a venturi fouling error corresponding to the achievable detectable value. Since

an all volatile chemical treatment and the strict chemical control will be utilized in the secondary plant, significant venturi fouling would not be expected for many years. However, since venturi fouling, if it should occur, would result in non-conservative RCS measurement, the staff has imposed a licensing condition to be resolved prior to completing the startup program. This condition requires that the capability of the trending program to detect 0.1% venturi fouling be verified or the Technical Specifications be revised with the appropriate value of venturi fouling uncertainty and the design DNBR limits be modified accordingly.

Excluding the venturi fouling uncertainty, the uncertainty of 2.1 percent for the RCS flow measured by the elbow taps, which are normalized with the calorimetric flow measurement, is acceptable. With the inclusion of 0.1 percent for venturi fouling, the overall RCS flow uncertainty of 2.2% is acceptable subject to the license condition described above.

The design model DNBR limits for the typical cell and the thimble cell are calculated using the approved ITDP and WRB-1 CHF correlation. Only the application of the plant-specific uncertainty values and the sensitivity factors on DNBR of the pertinent ITDP parameters to derive the design limit DNBR values required review. The applicant provided a detailed calculation of the design DNBR limits in the May 5, 1982 letter. It stated that the sensitivity factors and the ranges of applicability of the Byron ITDP parameters are the same as those used in WCAP-9500 with the exception of the range of vessel flow. However, the sensitivity factors of DNBR with respect to core power used for the Byron typical cell and thimble cell are in reverse order compared to the values used in WCAP-9500. The applicant indicated in the August 13, 1984 letter that the values applied to the Byron units are correct whereas the values given in WCAP-9500 are reversed. However, the use of the incorrect DNBR/power sensitivity factors in the determination of WCAP-9500 DNBR limits has a negligible effect on the final calculated DNBR limit values.

Using the plant-specific uncertainty values of the ITDP parameters with the uncertainty value of 2.2% for the RCS flow, the staff independent calculations agree with the DNBR limits provided in the applicant's response, i.e., the design DNBR limits are 1.336 for the typical cell and 1.317 for the thimble cell. Therefore, the design DNBR limits of 1.34 and 1.32, respectively, for the typical cell and the thimble specified in the FSAR are acceptable. The Byron design safety analysis use plant-specific safety DNBR limits of 1.49 and 1.47, respectively, for the thimble cells. Therefore, there is about 10.0 percent margin available for both typical and thimble cells to provide flexibility in the design, operation and analysis of the Byron units. The staff concludes that the DNBR calculation for the Byron units is acceptable.

4.4.2 Fuel Rod Bowing

Subsequent to issuance of the original SER, the Westinghouse topical report WCAP-8691, Revision 1, "Fuel Rod Bow Evaluation", has been approved by the staff. This rod bow penalty evaluation method applies statistical convolution of the critical heat flux test data and inter-fuel rod gap closure data to derive the rod bow penalty on DNBR. The use of this method results in a significantly lower rod bow penalty compared to the interim method previously used.

The applicant has submitted a table of rod bow penalty as a function of fuel burnup calculated with the approved Westinghouse method.

Since rod bow and gap closure increase with fuel burnup, the rod bow penalty on DNBR increases with burnup. However, even though the plant may be operated at higher burnup, the maximum fuel burnup used for the rod bow penalty calculation is 33,000 MWD/MTU. The reason for using 33,000 MWD/MTU as a cutoff point is because the physical burndown effect of the high peaking fuel rod will exceed the rod bow effects at higher burnup. By the time the fuel exceeds a burnup of 33,000 MWD/MTU, it is not capable of achieving limiting peaking factors due to the decrease in fissionable isotopes and the buildup of fission product inventory. Therefore, the rod bow penalty value of less than 3% DNBR at 33,000 MWD/MTU represents the maximum rod bow penalty for Byron plants having 17x17 optimized fuel assemblies. Since the use of the plant-specific design limit DNBR of 1.49 and 1.47 for the typical and thimble cells, respectively, has an inherent thermal margin of about 10.0%, the rod bow penalty can be accommodated by the available thermal margin. Therefore, no rod bow penalty is required for the Byron plant. A description of the available thermal margin and the rod bow penalty that is compensated by the thermal margin is included in the Basis of the Technical Specifications to avoid a multiple usage of the available margin.

4.4.7 Inadequate Core Cooling (ICC) Instrumentation

4.4.7.1 Clarification of Requirements

A clarification of requirements for inadequate core cooling instrumentation (ICCI) which is to be installed and operational prior to fuel load was provided in Item II.F.2 of NUREG-0737 "Clarification of TMI Action Plan Requirements." On November 4, 1982, the Commission determined that an instrumentation system for detection of inadequate core cooling (ICC) consisting of an upgraded subcooling margin monitor, core exit thermocouples, and a reactor coolant inventory tracking system is required for the operation of pressurized water reactor facilities.

4.4.7.2 Inadequate Core Cooling Detection System Design

In response to NUREG-0737 requirements, the Byron applicant has transmitted letters dated June 7, 1982, August 13, 1982, February 8, 1983, December 27, 1983 and July 6, 1984.

The applicant has selected an ICCI package for use in Byron consisting of three instrumentation subsystems: (1) Subcooled Margin Monitor to measure saturation/ superheat margin, (2) Heated Junction Thermocouples to monitor level/temperature in the upper region of the reactor vessel, and (3) Incore Instrumentation Thermocouples to measure temperature at the core exit.

The processing and display hardware includes two sub-systems of hardware - a qualified, safety related sub-system of ICC instrumentation and an unqualified, non-safety sub-system of ICC instrumentation. The backup displays for reactor level and core exit temperature are safety grade while the primary displays are nonsafety grade. Human factors engineering reviews have been applied to both types of display.

Plant specific procedures will be prepared based on the NRC approved Westinghouse Owner's Group guidelines. Minor departures from these guidelines will be necessary because the Byron heated junction thermocouple instrumentation covers a level range different from the standard differential pressure instruments.

Byron Unit 1 ICC instrumentation system will be operational by fuel load.

4.4.7.2.1 Subcooled Margin Monitor (SMM)

The primary display for the subcooling margin monitor (SMM) is the plant computer (CRT) which is mounted on the main control board. The plant process computer will compute the degrees of subcooling for saturation and output this number in digital form on the Safety Parameter Display System (SPDS) iconic display (CRT). Subcooling is determined from two wide range reactor coolant pressure instrument channels and sixty-five core exit thermocouples (CET). The display range is 0-3000 psig for pressure channels and 200-2300°F for CETs. The SMM is displayed on a control board indicator and can also be displayed on any of the various process computer output devices. Two digital CET monitors are provided as backup displays. The two thermocouple monitors are each powered from a separate ESF bus. There are 33 thermocouples on one monitor and 32 on the other. The thermocouples have been grouped so that either monitor can display representative temperatures across the entire core cross section.

The process computer system is a highly reliable system with four separate Central Process Units (CPUs). One CPU serves as a backup for any other CPU which may fail. The computer system is powered from either of the two independent AC sources with an automatic DC battery backup capability. The availability of the process computer is expected to be at least 99%. All signals to the computer are isolated from safety-related instrument channels by the qualified isolators.

The backup method to determine the subcooling margin is from two separate safety-related wide range reactor coolant pressure indicators and two separate safety-related core exit thermocouple monitors (which provide the average of the 10 highest CET temperature inputs). The operator reads the wide range pressure indicator to determine the allowable saturation curve and compares this temperature with the core exit thermocouple monitor reading (i.e., the average of the ten highest thermocouple temperatures) to obtain the subcooling margin. The operator also monitors the four containment pressure indicators and the two radiation monitors to determine whether the containment is at normal or adverse conditions (for use of the correct saturation curves). The adverse containment condition is defined as: (1) containment pressure greater than 5 psig or (2) containment radiation greater than 10^4 R/Hr.

The staff concludes that the proposed SMM display system will satisfy the NUREG-0737 Item II.F.2 requirements provided that the ability to trend the temperature input to the backup SMM is available by startup following the first refueling outage. This can be satisfied by adding a recorder or providing an acceptable alternate procedure for trending subcooling margin with the primary display unavailable. This will be addressed as part of the post-implementation review of the ICC instrumentation.

4.4.7.2.2 Core Exit Thermocouple System

The design of the in-core instrumentation system includes 65 Type K (Chromel-Alumel) thermocouples. The thermocouples are installed into guide tubes which penetrate the reactor vessel head and terminate at the exit flow end of selected fuel assemblies. The CET system is seismically and environmentally qualified to the requirements of IEEE 344-1975 and IEEE-323-1974, respectively. The isolation devises in the CET processors are accessible for maintenance following an accident.

The processing equipment for the CET will perform the following functions:

1. Process all core exit thermocouple inputs. Processing of 33 CET inputs will be performed by Channel A and 32 CET inputs by Channel B.

2. Provide 33 Channel A and 32 Channel B thermocouple outputs (8 per quadrant), respectively, to the backup displays.

3. Provide data link outputs to the process computer for all 65 thermocouple inputs. These outputs are isolated signals.

The primary displays for ICC detection are generated by the plant process computer using isolated outputs from the HJTC and CET processor cabinets and NSS protection system cabinets (for reactor coolant loop pressures). The main control room primary displays for ICC detection are part of the Safety Parameter Display System (SPDS). The primary display for CET is on SPDS. Additional displays include a spatially oriented core map indicating the temperature at each of the CET locations, a core exit temperature representative of the CET inputs, and trends of core exit temperature.

The backup displays for HJTC and CET are driven by a two channel system. Both the HJTC and CET systems use microprocessor-based designs for the signal processing function in conjunction with main control room indication, digital and analog, respectively. Each channel will accept and process ICC input signals and provide outputs to the channel related indicator and the plant process computer. Selectable temperatures from 65 core exit thermocouples, 33 for Channel A and 32 for Channel B are available on the backup displays.

4.4.7.2.3 Heated Junction Thermocouple System

Two identical HJTC probe assemblies are installed in each of the Byron units. These probe assemblies are identical to System 80 probe assemblies. There are eight heated/unheated thermocouple pairs (sensors) in each probe assembly. The HJTC sensor arrangement for the Byron units has two sensors located in the upper head and six sensors in the upper plenum. Only two sensors are placed in the upper head because once the water level falls below the top of the RCCA guide thimbles, the upper head inventory no longer communicates with the upper plenum and reactor core.

The processing equipment for the HJTC performs the following functions:

1. Determines if liquid inventory exists at the HJTC position.

2. Processes all inputs and calculated outputs for display.

3. Provides an alarm output to the plant annunciator system when any of the HJTC detects the absence of liquid level.

4. Provides control of heater power for proper HJTC output signal level.

5. Provides an input to the process computer for percent liquid inventory above the fuel alignment plate.

The primary display provides liquid level inventory above the fuel alignment plate and trends of liquid level inventory. The backup HJTC display provides percent liquid inventory level above the fuel alignment plate derived from the eight discrete HJTC positions, unheated junction temperature at eight positions, and heated junction temperature at eight positions.

4.4.7.3 Evaluation

The staff has reviewed the applicant's submittals and concludes:

1. The documentation in accordance with NUREG-0737 Item II.F.2 and the committed schedule for implementation of final ICC instrumentation are acceptable for an operating license. However, review of the final design for acceptability will not be complete until after the installation and preoperational testing of the HJTC level monitoring system is complete. An Implementation Letter Report is required to complete the review for implementation approval of the installed HJTC system;

2. The ICC system consisting of the final CET and HJTC instrumentation is acceptable for operation;

3. The modified emergency procedures for operation of the final ICCI must conform to generic EOP guidelines relating to use of the HJTC system or deviations must be identified and explained prior to 5% power; and

4. A means for trending subcooling margin with the primary display unavailable should be established prior to startup following the first refueling outage.

5 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 RCPB Inservice Inspection and Testing

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

5.2.4.3 Evaluation of Compliance of Byron Unit 1 with 10 CFR 50.55a(g)

This evaluation supplements conclusions in this section of the original SER which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g).

The Preservice Inspection (PSI) Program complies with the requirements of the 1977 edition of the Code, including Addenda through Summer 1978, except where specific relief is requested. In letters dated March 1, 1983, August 26, 1983, December 6, 1983, December 14, 1983, February 17, 1984, and April 18, 1984, the applicant submitted revised weld examination tables for the PSI Program along with notes clarifying the extent of examinations performed on particular items and requests for relief from ASME Section XI Code requirements which the applicant has determined not to be practical. The relief requests were supported by information pursuant to 10 CFR 50.55a(a)(2)(i). The staff evaluated the ASME Code required examinations that the applicant determined to be impractical and, pursuant to 10 CFR Part 50, Section 50.55a(a)(2), has allowed relief from the impractical requirements that, if implemented, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Based on the granting of relief from these preservice examination requirements, the staff concludes that the preservice inspection program for Byron Station Unit 1 is in compliance with 10 CFR Part 50, Section 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix I to this report.

By letter dated August 13, 1984, the applicant has committed to submit the initial inservice inspection program within six months after issuance of the operating license. Thus, License Condition 3 is no longer needed. This program will be evaluated after the applicable ASME Code Edition and Addenda can be determined based on Section 50.55a(b) of 10 CFR Part 50, but before the first refueling outage when inservice inspection commences.

5.2.4.4 Evaluation of Compliance of Byron Unit 2 with 10 CFR 50.55a(g)

The PSI Program for Byron Station Unit 2 has not been submitted and will be evaluated by the staff after the Applicant makes a decision on the applicability of the Unit 1 program to Unit 2.

5.4 Component and Subsystem Design

5.4.2 Steam Generators

5.4.2.2 Steam Generator Tube Inservice Inspection

5.4.2.2.2 Evaluation of the Inspection Program

In the original SER, the staff identified a generic problem concerning a potential for tube degradation caused by flow-induced vibration in the preheater section of Westinghouse Model D steam generators. The staff evaluation of the information submitted by the Commonwealth Edison Company with their letter of December 16, 1983, relative to the changes being made to the Byron steam generators to minimize tube vibration, is as follows.

The potential for tube well degradation due to flow induced vibration in Westinghouse Models D4 and D5 steam generators has been thoroughly evaluated and documented in NUREG-1014, "Safety Evaluation Report Related to Model D4/D5 Steam Generator Design Modification."

The primary cause of tube vibration in heat exchangers is hydrodynamic excitation due to secondary fluid flow on the outside of the tubes. In the range of normal steam generator operating conditions, the effects of primary fluid flow inside the tubes and mechanically induced tube vibration are considered to be negligible.

To evaluate flow induced tube vibration in the preheater region of the tube bundle, Westinghouse undertook an extensive program employing data from operating plants, full and partial scale model tests, and analytical tube vibration models. Operating plant data consisted of tube wear data from tubes removed from steam generators, eddy current tests and tube motion data from accelerometers installed inside selected tubes. Model testing generated tube wear data, flow velocity distributions, tube motion parameters, and flow-induced tube vibration forcing functions. The tube vibration analyses applied the forcing functions to produce tube motion data. The results of these evaluations were consistent with the early operating experience of preheat steam generators.

On the basis of the above extensive model test and analysis program, Westinghouse designed, verified, and implemented a modification to the steam generator to reduce tube vibratory response to preheater inlet flow excitation. Additionally, the magnitude of the flow forcing function was reduce through implementation of a preheater flow bypass arrangement in the feedwater system. The vibration of the performance of the modifications in reducing tube excitation and response was done with input from a full-scale test under simulated conservative flow and tube support conditions.

The above design modifications developed by Westinghouse for the preheater section of Models D4 and D5 steam generators provide a substantial reduction in tube vibration. As a result, the potential for tube wear has been reduced to within acceptable levels.

In the Model D4/D5 steam generators in Byron Units 1 and 2, the modifications consist of pending selected tubes into the baffle plates in the preheater, and splitting the feedwater flow through the auxiliary feedwater nozzle. The close support condition, resulting from tube expansion at the supports, significantly

changes the response frequency and also the G-Delta value (product of the peak to peak acceleration and root-mean-square, RMS, displacement). The G-Delta parameter provides a measure of tube wear due to vibration. A reduced value of G-Delta is indicative of diminished potential for tube wear. The split feed-water flow reduces the mass flow and velocity of the fluid in the preheater section. Both modifications combine to provide a substantial improvement by reducing the potential for tube wear.

The design modifications and their consequences for steam generators and plant performance were reviewed extensively by the NRC Staff and an independent panel of experts. In NUREG-1014, the staff concluded that the proposed modification assures substantial improvement by reducing the potential for tube wear to within acceptable levels. This conclusion was reached after a thorough review of the test models and testing results as well as evaluation of analytical models and analytical results.

Fatigue of the tubes in the preheater region which are subject to flow-induced excitation is not a concern since the maximum resultant stresses in the tube are below the endurance limit of the material.

For areas of the tube bundle other than the preheater, parallel flow analyses were performed to determine the vibratory deflections. These analyses indicate that the flow velocities are sufficiently low such that they result in negligible fatigue and vibratory amplitudes. The support system, therefore, is deemed adequate with regard to parallel flow excitation.

To evaluate crossflow at the exit of the downcomer, flow to the tube bundle and at the top of the bundle of the U-bend area, Westinghouse performed an experimental research program of crossflow in tube arrays with the specific parameters of the Model D4/D5 steam generator. Air and water model tests were employed. The results of this research indicate that these regions of the bundle are not subject to the vortex shedding mechanisms of tube excitation. Vortex shedding was found not to be a significant mechanism in these two regions for the following reasons:

a. Flow turbulence in the downcomer and tube bundle inlet region inhibit the formation of Von Karman vorticies.

b. Both axial and crossflow velocity component exist on the tubes. The axial flow component disrupts the Von Karman vorticies.

This research program was also the basis for evaluation of the fluid elastic mechanism associated with cross flow at the tubesheet. The evaluation showed the adequacy of the tube support arrangement.

Flow turbulence can result in some tube excitation in these regions. This excitation is of little concern, however, since:

a. Maximum stresses in the tubes are at least an order of magnitude below the fatigue endurance limit of the tube material, and

b. Tube support arrangements preclude significant vibratory motion.

In summary, tube vibration has been thoroughly evaluated. Mechanical and primary flow excitation are considered negligible. Secondary flow excitation has been evaluated. From this evaluation, the staff has concluded that the proposed expansion of selected tubes and splitting the feedwater flow through the auxiliary feedwater nozzle provides a reduction in tube vibration and in the potential for tube wear to within acceptable levels. Any tube wear resulting from the tube vibration would be limited and would progress slowly. This allows use of a periodic tube inservice inspection program for detection and followup of tube wear. This inservice inspection program, in conjunction with tube plugging criteria, provides for safe operation of the Model D4/D5 steam generators. Thus, Outstanding Item 10 is considered closed.

5.4.3 Residual Heat Removal System

The original SER stated that applicant had to perform the natural circulation test required by BTP RSB 5-1 prior to startup following the first refueling outage if the Diablo Canyon tests are not satisfactorily completed. In FSAR Amendment 39, Question 212.154, the applicant made a commitment acceptable to the staff. Therefore, License Condition 12 is no longer necessary.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.5 Minimum Containment Pressure Analysis for Performance Capability Studies on the ECCS

Appendix K to 10 CFR Part 50 requires that the value of containment pressure in evaluating the cooling effectiveness of the emergency core cooling water during core reflood shall not exceed a pressure calculated conservatively for that purpose. Also, the calculation must include the effect on operation of all installed containment pressure reducing systems and processes.

The staff stated in the original SER that the applicant's analysis was acceptably conservative and in conformance with the provisions of BTP CSB 6-1, "Minimum Containment Pressure Model for PWR ECCS Performance Evaluation," with three exceptions. These exceptions have, subsequent to the publication of the SER, been resolved, as described below.

1. The applicant assumed an essential service water (ESW) temperature of 100°F for calculating the heat removal capacity of the reactor containment fan coolers (RCFCs). BTP CSB 6-1 states that the minimum cooling water temperature be used to maximize the heat removal capacity of the RCFCs. The applicant has redone the analysis (see response to Question 022.24, FSAR Amendment 43) assuming an ESW temperature of 45°F, which is acceptable.

2. The applicant assumed a 40-second delay in RCFC initiation, whereas other information provided by the applicant indicated that the delay time could be as short as 17 seconds. For the reanalysis performed in response to Question 022.24, FSAR Amendment 43, the applicant assumed an initiation time of 15 seconds, which is acceptable.

3. The applicant did not consider the effect of miniflow purge system operation at the onset of a LOCA on the containment pressure response. The applicant has provided an analysis of this effect (See response to Question 022.23, FSAR Amendment 39). The applicant assumed the system isolation valves would be fully closed 7.62 seconds after onset of the accident; this time is based on the time required to reach the isolation set point, the signal delay time, and a 5-second valve closure time. Discharge of containment atmosphere through the supply and exhaust lines was assumed for the entire 7.62 seconds; flow resistance effects and the reduction in flow area due to the closing of the valves were conservatively ignored in calculating the containment atmosphere release. The applicant calculated a containment pressure drop of less than 0.05 psi, and estimated that the peak fuel clad temperature would increase by approximately 1°F. Therefore, the staff concludes that the effect of operation of the miniflow purge

system on the minimum containment pressure analysis is insignificant and may be ignored.

In conclusion, the applicant has provided a reanalysis of the minimum containment pressure transient which is in accordance with the provisions of BTP CSB 6-1 and which resolves previous staff concerns. The FSAR has been revised to reflect the effect the revised minimum containment pressure transient has on the ECCS performance capability. Therefore, the staff considers Confirmatory Issue 19 to be resolved.

6.2.5 Combustible Gas Control System

The staff stated in the original SER that the two hydrogen recombiners at the Byron site, including their associated piping and valves, will perform the intended hydrogen control function assuming any single active component failure coincident with loss of offsite power. The acceptability of this statement, however, was contingent on the incorporation of a design modification whereby the suction and discharge valves associated with a recombiner would receive electrical power from the same Class 1E power supply that serves the recombiner. This will preclude the loss of both recombiner trains in the event of a loss of one of the two Class 1E power supply divisions, assuming the suction and discharge valves are normally closed. The SER also stated that the applicant committed to make the design change described above prior to initial fuel loading. By letter dated February 22, 1984, the applicant informed the staff that the present recombiner system design differs from that described in the SER with respect to the power supplies serving the valves; the applicant also provided justification for the design, as discussed below.

There are two hydrogen recombiners permanently installed at the station. Through the use of cross-tie piping, either recombiner may be used on either unit. The suction and discharge valve operators are powered from opposite division Class 1E power supplies. Specifically, recombiner 1 and the suction line valve are powered from Division E11, and the discharge line valve is powered from Division E12. Recombiner 2 and the suction line valve are powered from Division E12, and the discharge line valve is powered from Division E11. Also, the discharge line valves are normally kept open. The suction and discharge valves are not powered from a common power supply because certain single failures in that configuration could compromise recombiner system effectiveness.

The present electrical division assignments prevent backflow through a failed recombiner. As presently arranged, both hydrogen recombiners operate in parallel, using the same suction and exhaust piping from each containment. With a Class 1E power supply failure, sufficient redundancy exists to operate at least one recombiner at design capacity. If each recombiner and its suction and discharge valves were powered from the same supply, a single failure of either Class 1E power supply could prevent isolation of the associated recombiner piping circuit. Flow from the redundant recombiner would follow the path of least resistance and backflow through the failed recombiner; the design flow rate of air from the containment would not be achieved.

The applicant's hydrogen recombiner system design eliminates the potential for backflow as discussed above, and is, therefore, an improvement on the design described in the SER. This is, however, contingent on the recombiner discharge valves being kept open during normal operation; the applicant must assure that

appropriate administrative controls are instituted to maintain the discharge valves open. The applicant has committed to satisfy this requirement.

Based on the above discussion, the staff concludes that the applicant's recombiner system design is acceptable.

6.2.6 Containment Leakage Testing

Fluid systems penetrating containment which may be opened to the containment atmosphere under post-accident conditions must, in general, be vented and drained during containment integrated leakage rate (Type A) testing to ensure exposure of the system containment isolation valves to the test medium (containment air) and test differential pressure. In so doing, potential containment atmosphere leak paths will be included in the Type A test. Certain exceptions are allowed, as noted in paragraph III.A.1(d) of Appendix J to 10 CFR 50.

As stated in the original SER, the applicant had not finished preparing the Type A test procedures concerning venting and draining, but did commit to comply with the appropriate requirements of Appendix J. The staff stated that, once the applicant's procedures had been completed, the staff would confirm that proper venting and draining provisions would be employed.

By letter dated April 19, 1983, the applicant submitted information describing the venting and draining provisions. Fluid systems penetrating containment will be vented and drained during type A tests, with the following exceptions:

> Paragraph III.A.1(d) of Appendix J states, in part, that those portions of the fluid systems that are part of the reactor coolant pressure boundary and are open directly to the containment atmosphere under post-accident conditions and become an extension of the boundary of the containment shall be vented to the containment atmosphere during Type A tests. It further states that portions of closed systems inside containment that penetrate containment and rupture as a result of a LOCA shall be vented to the containment atmosphere. The applicant submits that the main steam lines, the main feedwater and auxiliary feedwater lines, and the component cooling system excess letdown heat exchanger inlet and outlet lines do not fall into either category. These lines are not part of the reactor coolant pressure boundary, and are not postulated to rupture during a LOCA, since they satisfy the design provisions of Section II.o. of SRP 6.2.4, "Containment Isolation System," for closed systems inside containment. Therefore, the staff concludes that these lines need not be vented and drained during Type A tests.
>
> Paragraph III.A.1(d) of Appendix J also states that systems required to maintain the plant in a safe condition during the test shall be operable in their normal mode, and need not be vented, and systems normally filled with water and operating under post-accident conditions need not be vented. The applicant submits that the residual heat removal system suction lines, the fire protection system lines, and the chemical and volume

control system (CVCS) charging and loop fill headers are required to maintain the plant in a safe condition during the test. Also, the containment isolation valves in the CVCS charging and loop fill headers will be isolated post-accident and sealed by high-pressure water from the centrifugal charging pumps, and therefore do not constitute a potential leak path for containment atmosphere. Therefore, the staff concludes that the above lines need not be vented and drained during Type A tests.

The applicant submits that the essential service water lines to the reactor containment fan coolers, the safety injection system injection lines, and the chemical volume and control system seal injection lines are normally filled with water and operating under post-accident conditions. The staff concurs, and concludes that these lines need not be vented and drained during Type A tests.

In summary, the staff concludes that the lines specified in the applicant's letter dated April 19, 1983, and discussed above, need not be vented and drained during the performance of Type A tests. This resolves Confirmatory Issue 20.

6.3 Emergency Core Cooling System

6.3.4 Testing

6.3.4.1 Preoperational Tests

The original SER indicated that the staff would confirm the sump design by reviewing the results of ECCS testing. Staff review of the test results is documented in Inspection Report No. 50-454/84-24 and No. 50-455/84-17, transmitted by letter dated June 12, 1984. It concludes that Confirmatory Issue 21 is closed for Unit 1 only. Since the sump design for Unit 1 and Unit 2 is identical, the staff considers this issue closed for both units.

6.5 Fission Product Removal and Control System

6.5.1 Engineered Safety Feature (ESF) Atmospheric Cleanup System

6.5.1.1 Summary Description

The Byron SER indicated that the applicant had not included either moisture separators or heaters in the non-accessible area exhaust filter system or the fuel handling building exhaust filter system.

In the SER-CP, the staff took the position that relative humidity control to 70% was required for the incoming air to the ESF filter systems. The applicant has submitted two studies. One study provides an analysis showing that moisture separators are not required in the non-accessible area exhaust filter system, while the other study provides an analysis of the relative humidity anticipated in the inlet air to the fuel handling building exhaust filter system and to the non-accessible area exhaust filter system.

Because the staff had not completed its review of the relative humidity analysis at the time of issuance of the Byron SER, the staff had credited the above filter systems with a removal efficiency of 90% for elemental forms of radioiodine and removal efficiencies for organic forms of methyl iodine of 50% and 70% for the non-accessible area and fuel handling building exhaust filter systems, respectively. At that time, the staff indicated in the SER that the adsorber efficiency for organic radioiodines may be increased for the fuel handling building filter system and the non-accessible area exhaust filter system upon completion of the staff's review.

After the Byron SER had been issued, the staff took the position on a licensing action involving another plant that no air filtration unit could be credited as an ESF grade system unless the system included moisture separators. The Byron licensing board was notified that because the filter systems did not meet the specifications in Regulatory Guide 1.52, the charcoal adsorbers could fail to remove the amount of radioiodine assumed in the accident evaluations. Such a failure could result in doses exceeding the criteria of 10 CFR Part 100. The applicant was asked to respond to the staff's concerns about the exclusion of the moisture separators and the applicant has done so in its October 4, 1984 letter.

Since the initial Byron SER was issued, the applicant has amended the Byron FSAR on several occasions. Some of these changes have made it necessary for the staff to review previous conclusions presented in the Byron SER to ensure that those conclusions have not been negated. Some of the changes that the applicant has proposed involve the exceptions to Regulatory Guide 1.52. The applicant's initial conformance to this guide was covered in Section 6.5.1 of the SER. Some of the changes that the applicant has proposed with respect to these exceptions are as follows:

The auxiliary building and fuel handling building exhaust filter housings would not be leak tested to ANSI N509-1976 requirements because (1) the housings are at negative pressure with respect to their surroundings, (2) the housings are located in the auxiliary building general area which is a low airborne radiation area, and (3) any inleakage from the general area will not adversely affect releases. Filter mounting frame leak tests will be performed in accordance with ANSI N510-1980.

The control room emergency makeup air system filter housings would not be tested in accordance with ANSI N509 because the housings are at negative pressure and are located within the control room boundary. Therefore, any in-leakage would be from the control room environment into the housings. No alternative testing was proposed for any of the filter housings, however, filter mounting frame leak tests would be performed in accordance with ANSI N510-1980.

The remaining ESF system's ductwork would not be leak tested in accordance with ANSI N509-1976 because the ductwork is at negative pressure with respect to its surroundings and any in-leakage would be filtered prior to release. No alternative testing for the ductwork in lieu of testing in accordance with ANSI N509 was proposed.

Previously, the staff had accepted that the flow rate through the ESF filter trains would not be recorded because the fans are fixed speed

fans and the applicant has a curve of flow rate versus pressure drop. Since Δp across all HEPA filters was to be recorded and because the applicant was to have a technical specification requirement that would verify flow rate as a function of pressure drop, this was acceptable. In Amendment 42 to the Byron FSAR, the applicant indicated that now only Δp across the HEPA filters, upstream of the charcoal adsorbers, would be recorded.

The applicant has stated that airflow from the non-accessible area exhaust filters and the control room emergency make-up air filters will be continuously sensed and controlled to maintain constant airflow. Therefore, flow rates through the filter trains will not be affected by variations in pressure drops across the filters within the train. High and low fan differential pressure alarms are provided on the main control panel to alert the operator to high or low airflow conditions and airflow indicators are provided on local control panels in accessible areas within the control rooms so that actual flow rates can be obtained. The applicant did not address the recording of flow rates through the fuel handling building filtration unit. The applicant has indicated that the Δp alarms on the upstream HEPA filters will have setpoints which will indicate a deviation of $\pm$ 10% from the rated flow.

The applicant has proposed in an amendment to the FSAR that the recirculation adsorber of the control room be deleted from the Byron Station design because it is not required to mitigate the consequences of a radiological incident or a toxic gas challenge.

6.5.1.2 Evaluation Findings

The staff has evaluated the applicant's analysis on the relative humidity expected in the inlet air to the non-accessible area and the fuel handling building exhaust filter systems. Based upon this evaluation, the staff concludes that the relative humidity expected in the inlet air to the fuel handling building exhaust filter system will be greater than 70%, while that to the non-accessible area exhaust filter system would be less than 70%. The staff concluded that entrained moisture would not be a problem if a fuel handling accident occurred in the fuel handling building; therefore, moisture separators are not required for the filtration unit associated with that building. For the non-accessible area exhaust filter system, the staff concluded, on the basis of the review of the applicant's analysis, that there was adequate dilution of the entrained water resulting from a 50 gpm pump seal failure in one of the non-accessible area cubicles for 30 minutes such that moisture separators are not required for the non-accessible area exhaust filter system either. With these conclusions, the staff has determined that the appropriate removal efficiencies for radioiodine for the non-accessible area exhaust filter system are 95% for both elemental and organic forms of radioiodine and that the allowable methyl iodide penetration for the laboratory test of the charcoal is 1%. For the fuel handling building filter exhaust system, the staff determined that the appropriate removal efficiencies for the elemental and organic forms of radioiodine would be 90% and 30%, respectively, with the allowable penetration for the methyl iodide test being 10%.

The staff has reviewed changes made to the FSAR since the Byron SER was published, including the new and revised exceptions taken to Regulatory Guide 1.52, and the applicant's October 18, 1984 letter. With respect to these exceptions, the following comments apply.

Although it is commonly assumed that all leakage will be inleakage in a negative pressure system, outleakage can occur under some conditions even when the system is operating at its design negative pressure and particularly when the system is down. Therefore, it is important that the filter housings be leak-tight. Any inleakage would be drawn from the particular room or cubicle in which the filtration unit is located.

The applicant has committed to performing a mounting-frame-pressure leak test. A mounting-frame-pressure leak test verifies that there are no leaks through the HEPA filter and adsorber mounting frames or through the seal between the mounting frames and the housing. The test also verifies that there exists no bypassing of the mounting frames through electrical conduits, drains, compressed air connections, and other inadvertent leak paths. Typical sources of leaks are weld cracks and incomplete welds. The staff finds the performance of the mounting-frame-pressure leak test acceptable.

The applicant has indicated that the ductwork will not be leak tested in accordance with ANSI N509-1976 and has not proposed any alternative testing for the ductwork; even the less rigorous testing of ANSI/ASME N509-1980. The staff initially accepted the applicant's exception to leak testing the ductwork because all radioactivity would leak into the ductwork and would be filtered. However, further consideration of this exception has raised other questions.

Obviously, the additional inleakage to the ducts will result in an increase in the quantity of radioactivity released offsite in the event of an accident. However, more importantly, a greater problem exists with respect to the potential degradation of the charcoal in the ESF filter trains due to the unknown transmission of fumes from painting, fires or chemical releases via the leaky ductwork. Such a transmission could be chronic and plant personnel may never laboratory-test the charcoal until the scheduled refueling outage. In the intervening months, the plant may have been operating with charcoal incapable of performing at the efficiency assumed in the staff's SER. The staff is also concerned that the relative humidity seen by the charcoal adsorbers may be altered due to the variation in the flow rate brought about by this ductwork inleakage from the various sources to the filtration units and that the analyses presented by the applicant justifying the exclusion of electrical heaters may be invalidated.

In a meeting with the applicant, the staff was told that because of the duct routing, the direction of airflow from clean to dirty, and system operation; leakage into the accessible or non-accessible area exhaust ductwork in the general access areas will be clean, and in relation to the overall flow rates, should be a relatively small quantity. In addition, inleakage into the non-accessible area ductwork, along with the exhaust from other non-accessible cubicles, will be monitored by radiation monitors located in branch ducts at the inlet to the filter plenums. This exhaust air will then be directed to charcoal adsorbers if levels exceeded monitor setpoints. In addition, plant vent stack radiation monitors measure and record particulate, noble gas and iodine concentrations and alarm conditions when they exceed monitor setpoints.

With respect to degradation of the carbon adsorber due to unknown transmission of fumes, the applicant stated that the charcoal adsorbers would not be in the airflow path unless airborne radioactive material was present in the non-accessible area exhaust in excess of monitor setpoints. The applicant indicated that leakage into the ductwork would not result in any significant increase in transmission of chemical fumes to the adsorbers. If a release did occur in the general area of the auxiliary building, the fumes would end up on the adsorbers even if there were no inleakage due to the general layout of the building, the principle air movement pattern in the building (i.e., direction of airflow from general areas to cubicles), the open hatches and stairwells throughout the building, and the existence of natural thermal ducts through the general area. Therefore, it has to be assumed that a release in any area, other than inside an accessible cubicle, could end up on the charcoal adsorbers if it is not removed by other means (i.e., plate out or other absorption mechanisms). The applicant also stated that since gross leakage will be detected through the duct inspection and testing and balancing, the remaining leakage for the type of duct construction at Byron will result in very insignificant leakage compared to the total system flow rate. The applicant also indicated that the correlation of audible leaks with actual measurements of leakage has led to the conclusion that by eliminating all audible leaks, the total leakage will be less than 1% of the system capacity. ANSI N509-1980 requires the sealing of all audible leaks. The applicant has stated that all ESF system ductwork will be visually inspected and audibly checked for leaks and that all audible leaks will be sealed.

While the technical specifications will require that the adsorber material be tested following painting, fire or chemical release, the staff is concerned that the transmittal of such fumes may proceed undetected through such pathways as inleakage through the ductwork. In addition, it is likely that such fumes may proceed to the adsorbers through damper leakage. Therefore, the applicant will post signs throughout the auxiliary building and control room envelope stating that, prior to any painting, the control room operator shall be contacted to determine whether the adsorbers are operating. The sign will also state that, following any fire or chemical release event, the control room operator or individual cognizant of the technical specification surveillance requirements be contacted and a determination made whether the integrity of the adsorber material could have been compromised.

The applicant performed an analysis to determine whether inleakage into the ductwork resulted in a change in the relative humidity of the air in the various non-accessible area cubicles and, thus, negated a previous analysis provided by the applicant which justified the exclusion of electrical heaters. In this analysis, the applicant assumed 10% inleakage into the exhaust ducts in the general area, adjusted the flow rates assumed in the moisture content calculations accordingly, and assumed that the inleakage air was at 100% RH. The applicant calculated that the relative humidity would be increased from 51% to approximately 59% and that leakage rates up to 30% of the airflow rate could be tolerated and still the exhaust air relative humidity would be below 70%. Based upon this analysis, the staff concluded that the inleakage associated with the ductwork would not result in the negation of the applicant's previous submittal justifying the exclusion of electrical heaters.

The staff finds the applicant's method for ensuring that the flow rate in the non-accessible area exhaust filters systems and the control room emergency

make-up air filters is maintained within ± 10% of its design flow acceptable provided the Δp alarm setpoints on the upstream HEPA filters are established to indicate a deviation in flow of ± 10%.

One item which needs clarification is the efficiencies assumed for the calculation of doses to the control room operator. Section 6.4 of the Byron SER found the doses to the control room operator acceptable, based upon supplying 6000 cfm of makeup air through the control room HVAC emergency makeup air filter units and filtering this air and 45,000 cfm of recirculated control room air through a prefilter and a two inch impregnated charcoal adsorber. The applicant had indicated in an amendment to the FSAR that the recirculation adsorber is only required at Braidwood, not Byron, for mitigating either high chlorine levels or high radioactivity levels, or for smoke control. This recirculation adsorber was not addressed in Section 6.5.1 of the Byron SER, but the staff concluded that this adsorber is required for the Byron Station to meet the dose criteria associated with GDC 19. The staff assumed a charcoal adsorption efficiency of 95% for elemental and organic iodide for the recirculation adsorber and 99% for particulate, elemental, and organic forms of radioiodide for the control room HVAC makeup air filter units. This allowed the staff to conclude, in Section 6.4 of the Byron SER, that GDC 19 was met. Therefore, it is the staff's position that the recirculation charcoal adsorber must not be removed from the Byron Station control room HVAC system. Technical specifications covering its operability are required.

However, the applicant is investigating other alternatives to operation of the recirculation charcoal adsorber, including some design modification. Therefore, the staff will condition the license so that, prior to exceeding 5% power, the applicant must demonstrate that the radiological exposure to the control room operators during postulated accidents will be within the limits specified in General Design Criterion 19 and implement any necessary modification prior to exceeding 25% power.

Thus, with the exception of this License Condition, Outstanding Issue 18 is considered closed.

The staff has determined that an exemption from GDC-19 of Appendix A is needed. GDC-19 requires that the control room have adequate radiation protection to permit access and occupancy under accident conditions. Operation at or below 25% power will not generate fission products such that, with the present control room design, the control room operators would be exposed to doses in excess of those prescribed in GDC-19 in the event of an accident. The license condition requires that the applicant implement prior to exceeding 25% power any modifications needed to meet GDC-19. Therefore, the staff concludes that the exemption from the requirement of GDC-19 will not endanger life or property or the common defense and security and is otherwise in the public interest.

6.6 Inservice Inspection of Class 2 and 3 Components

This section was prepared with the technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

6.6.3 Evaluation of Compliance of Byron Unit 1 with 10 CFR 50.55a(g)

This evaluation supplements conclusions in this section of the original SER which addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g).

The PSI Program complies with the requirements of the 1977 Edition of the Code including Addenda through Summer 1978, except where specific relief is requested. In letters dated March 1, 1983, August 26, 1983, December 6, 1983, December 14, 1983, February 17, 1984, and April 18, 1984, the applicant submitted revised weld examination tables for the PSI Program along with notes clarifying the extent of examinations performed on particular items and requests for relief from ASME Section XI Code requirements which the applicant has determined to be not practical. The relief requests were supported by information pursuant to 10 CFR 50.55a(a)(2)(i). The staff evaluated the ASME Code required examinations that the applicant determined to be impractical and, pursuant to 10 CFR Part 50, Section 50.55a(a)(2), has allowed relief from the impractical requirements that, if implemented, would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Based on the granting of relief from these preservice examination requirements, the staff concludes that the preservice inspection program for Byron Station Unit 1 is in compliance with 10 CFR Part 50, Section 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix I to this report.

By letter dated August 13, 1984, the applicant has committed to submit the initial inservice inspection program. Thus, License Condition 3 is no longer needed. This program will be evaluated after the applicable ASME Code Edition and Addenda can be determined based on Section 50.55a(b) of 10 CFR Part 50, but before the first refueling outage when inservice inspection commences.

6.6.4 Evaluation of Compliance of Byron Unit 2 with 10 CFR 50.55a(g)

The PSI Program for Byron Station Unit 2 has not been submitted and will be evaluated by the staff after the applicant makes a decision on the applicability of the Unit 1 program to Unit 2.

7 INSTRUMENTATION AND CONTROL

7.6 Interlock Systems Important to Safety

7.6.2 Specific Findings

7.6.2.7 TMI Action Plan Item II.K.3.1, Installation and Testing of Automatic Power-Operated Relief Valve Isolation Sytem

By letter dated December 27, 1983, the applicant referred to a Westinghouse generic report (WCAP-9804) in addressing NUREG-0737 Item II.K.3.2, "Report on Overall Safety Effect of Power-Operated Relief Valve (PORV) Isolation System."

The applicant asserted that the generic report was applicable to Byron Station, Units 1 & 2. The staff has made an independent assessment of the frequency of a small-break loss-of-coolant accident (SBLOCA) due to a stuck-open PORV or safety valve (SV). Based on the similarity of the safety valves (Crosby Model HP-BP-86) that used by many other Westinghouse plants, and based on the EPRI test results (see EPRI-2628-SR), the staff estimates the failure rate of the Byron SVs to be similar to that of other Westinghouse plants, 1×10^{-2}/demand. Because the design and operation of Byron is similar to that of Zion, the staff expects a similar SV challenge frequency at Byron to that at Zion. Therefore, the staff estimate of SBLOCA frequency due to a stuck-open SV is 3×10^{-4}/reactor year, the same as for Zion.

Based on the similarity of the PORVs to that used by Zion, and the similarity in design and operation of the two plants, the staff estimates a SBLOCA frequency due to a stuck-open PORV of 1.5×10^{-3}/reactor-year. The SBLOCA frequency is within the range of the SBLOCA frequency of 10^{-4} to 10^{-2} per reactor-year given in WASH-1400. The staff has therefore determined that the requirements of NUREG-0737 Item II.K.3.2 are met with the existing PORV, SV, and high-pressure reactor trip setpoints. According to the criteria set forth in the clarification of Item II.K.3.2 in NUREG-0737, there is no need for an automatic PORV isolation system. Therefore, Confirmatory Item 28, TMI Item II.K.3.1, is considered closed.

9 AUXILIARY SYSTEMS

9.1 Fuel Handling and Storage

9.1.5 Overhead Heavy-Load Handling Systems

As a result of Generic Task A-36, "Control of Heavy Loads Near Spent Fuel," NUREG-0612, "Control of Heavy Loads at Nuclear Plants" was developed. Following the issuance of NUREG-0612, a generic letter dated December 22, 1980 was sent to all operating plants, applicants for operating licenses and holders of construction permits requesting that responses be prepared to indicate the degree of compliance with the guidelines of NUREG-0612. The responses were to be made in two stages. The first response (Phase I, Section 5.1.1 of NUREG-0612) was to identify the load handling equipment within the scope of NUREG-0612 and to describe the associated general load handling operations such as safe load paths, procedures, operator training, special and general purpose lifting devices, the maintenance, testing and repair of equipment and the handling equipment specifications. The second response (Phase II) was intended to show that either single-failure-proof handling equipment was not needed or that single-failure-proof equipment had been provided. This safety evaluation report contains the staff's evaluation of Phase I. An evaluation of Phase II will be the subject of future correspondence.

By letter dated December 22, 1980, Commonwealth Edison Company was requested to review their provisions for handling and control of heavy loads at Byron to determine the extent to which the guidelines of NUREG-0612 are satisfied and to commit to mutually agreeable changes and modifications that would be required in order to fully satisfy these guidelines.

The staff and its consultant, Idaho National Engineering Laboratory (INEL) have reviewed the applicant's submittals for Byron/Braidwood Stations. As a result of its review, INEL has issued the attached TER (Appendix J). The staff has reviewed the TER and concurs with its findings that the guidelines of NUREG-0612, Section 5.1.1 have been satisfied.

Consequently the TER is incorporated as a part of this SSER. The staff concludes that Phase I of NUREG-0612 for Byron is acceptable. The staff review of Phase II of NUREG-0612 for Byron will be the subject of a future evaluation. Until that review is complete, the following condition shall be included in the Byron operating license: Prior to startup following the first refueling outage, the licensee shall have made commitments acceptable to the NRC regarding the guidelines of Sections 5.1.2 through 5.1.6 of NUREG-0612 (Phase II-nine-month response to the NRC generic letter dated December 22, 1980).

9.2 Water Systems

9.2.2 Reactor Auxiliaries Cooling Water Systems

The original SER indicated that during the limiting mode of plant operation, a simultaneous LOCA in one unit and safe shutdown of the other, the component

cooling water system (CCWS) is split on receipt of an engineered safety features actuation signal (ESFAS). For purposes of clarification, this splitting is performed manually by the operator sometime after receipt of an ESFAS. The staff's original approval was based on this design.

9.3 Process Auxiliaries

9.3.2 Process and Post Accident Sampling System

TMI Action Item II.B.3 Postaccident Sampling Capability

By Amendment 38 and letters dated August 26, and October 26, 1982, the applicant provided a description of systems, equipment, and procedures to be used for sampling the reactor coolant and the containment atmosphere following an accident resulting in core degradation. The applicant has also provided information on methods of transporting samples for off-site analyses. The post-accident sampling system (PASS) provides the capability to obtain and analyze samples within three hours of the time a decision is made to sample. Samples can be obtained from the reactor coolant system, containment sumps and containment atmosphere under accident conditions. Provisions are incorporated to obtain grab samples for offsite analyses.

The applicant also provided a description of radiochemical analyses capabilities including provisions to identify and quantify radioactive isotopes (noble gases, iodine and cesium isotopes and nonvolatile isotopes). Analyses capabilities are also incorporated for dissolved gases, chloride, and boron concentrations in liquid samples. The PASS also provides the capability to measure hydrogen concentration in the containment atmosphere. Sample lines are routed to an accessible area and shielded to protect operators. An isolated auxiliary system is not required to be operational in order to use the PASS. Furthermore, all valves in the High Radiation Sampling System are designed for the environment in which they need to operate. The PASS is also capable of performing inline analysis of hydrogen, dissolved oxygen, and chloride in the primary coolant during normal and accident conditions. Provisions will also be made to purge the sample lines for reducing plate out, for minimizing sample loss or distortion, for preventing blockage of sample lines for disposal of samples, and for passive flow restrictions. Sufficient shielding will be provided to meet the requirements of GDC 19 in Appendix A to 10 CFR Part 50, assuming the source term defined in Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss-of-Coolant Accident for Pressurized Water Reactors." The applicant provided an alternative backup power source to the PASS for use during loss of off-site power. In addition, inline monitoring of dissolved oxygen at less than 0.1 ppm can be made if the reactor coolant chlorides concentration is greater than 0.15 ppm. Based on review of Amendment 38 and the August 26, 1982 and October 26, 1982 letters, the staff concludes that the postaccident sampling system is acceptable, except for the Clarification Items (2), (10), and (11) identified in NUREG-0737 Item II.B.3.

By letters dated December 11, 1983, January 5, 1984 and May 4, 1984 the applicant provided additional information regarding Clarification Items (2), (10) and (11) in NUREG-0737.

The applicant provided a procedure for estimating the degree of reactor core damage based on the Westinghouse Owners Group generic methodology, Revision 1,

dated March 1984, using measured and predicted post-accident radionuclide concentration from failed fuels.

The procedure takes into consideration other physical parameters such as reactor core temperature data, reactor water level, sample location, and containment radiation levels and hydrogen concentrations. The staff concludes that these provisions meet Clarification Item (2) and are, therefore, acceptable.

The range, accuracy, and sensitivity of the radiological and chemical analysis was given by the applicant. Information was provided on the applicability of these procedures and instruments in the postaccident water chemistry and radiation environment. Containment atmosphere will be sampled and analyzed for hydrogen, oxygen, and gamma spectrum every six months. The postaccident sampling system is the same as the one used for routine sampling operations. The applicant has developed a special retraining program for all radiation-chemistry technicians for every six months. The staff concludes that these provisions meet Clarification Item (10) and are, therefore, acceptable.

The licensee has addressed provisions for purging to ensure samples are representative, size of sample line to limit reactor coolant loss from a rupture of the sample line, and ventilation exhaust from PASS filtered through charcoal absorbers and HEPA filters. The containment atmosphere sample line is heat traced to aid in obtaining representative samples. The staff concludes that these provisions meet Clarification Item (11) of Item II.B.3, and are, therefore, acceptable.

The staff concludes that all eleven Clarification Items are met and the postaccident sampling system is acceptable. Furthermore, by letter dated August 13, 1984, the applicant committed to have the postaccident sampling system operational prior to initial criticality. Therefore, License Condition 11 is no longer needed.

9.3.5 III.D.1.1 - Integrity of Systems Outside Containment Likely to Contain Radioactive Material

9.3.5.1 Summary Description

The applicant has provided a description of the program designed to reduce leakage from systems outside containment that would or could contain primary coolant or highly radioactive fluids during a serious transient or accident. The applicant's program will be initiated during the preoperational test phase.

The applicant has indicated that, prior to fuel load, all systems or portions of systems constructed in accordance with ASME Section III will be hydrostatically tested to 125% of the system's design pressure. In the case of gaseous systems, a pneumatic type pressure decay test at 125% of system's design pressure will be performed. All systems in the leak reduction program will be tested prior to initial plant startup during the Pre-Operational Test Program. During these tests, system walkdowns will be conducted by the System Test Engineer and deficiency reports will be generated for leakage and defective components. In addition to the individual system tests, integrated type tests such as Integrated Hot Functional (IHF) and Emergency Core Cooling System (ECCS) Full Flow Tests will be conducted. During these integrated tests, additional system walkdowns will be conducted for vibrational testing and inspection of

piping thermal expansion. Deficiency reports will also be generated during these walkdowns.

The applicant has indicated that, at the time Unit No. 1 reaches full power operation, a report will be submitted to the NRC staff detailing all recorded leakage and, as the direct result of the evaluation of this leakage, all preventive maintenance performed. The report will also identify general leakage criteria to be applied during the first fuel cycle as the basis for instituting corrective action in the form of preventive maintenance. Levels of leakage will be kept as low as practicable through this program's commitment to generate work requests for all practicable repairable leakage problems. The applicant has committed to reviewing leakage problems presenting ALARA concerns and to refine the leakage criteria over time as more information is accumulated through inspections. Thus, the criteria can be revised to incorporate new modifications and techniques designed to keep leakage as low as practicable. Prior to the start of the second fuel cycle, the applicant has committed to revising the general criteria based on the experience gained during the first operating cycle on Unit No. 1. These revised criteria will be used as the basis for the long term leakage monitoring program on Units 1 and 2.

The applicant has committed to leak testing the following systems or portions of a system which could contain highly radioactive gases or fluids:

(1) Chemical and Volume Control;
(2) Containment Spray;
(3) Radioactive Waste Gas;
(4) Offgas, including Hydrogen Recombiners;
(5) Residual Heat Removal;
(6) Safety Injection;
(7) Fuel Pool Cooling and Cleanup;
(8) Process Sampling; and
(9) Auxiliary Building Equipment Drains and Floor Drains.

The applicant has committed to performing integrated leak tests at least during each refueling outage on each system, or portions of systems, which could potentially contain highly radioactive fluids or gases. Station surveillance and procedures will be used to:

(1) monitor the leak testing of piping so that the appropriate lines are examined at the required intervals;

(2) direct leak tests examinations such that systems are tested at approximately operating pressures or higher;

(3) align systems such that all piping tested is properly pressurized;

(4) identify lines which contain gases that require pressure decay and/or metered make-up testing;

(5) quantify results of leakage examinations; and

(6) initiate corrective action.

Systems or portions of systems which will be excluded from the leak reduction program include:

(1) Chemical and volume control;

(a) chemical mixing tank and associated piping,

(b) boric acid addition portion of the system,

(c) resin fill tank and associated piping,

(2) Containment spray;

(a) spray additive tank and associated piping,

(b) six inch recirculation line from containment spray pumps back to refueling water storage tank,

(3) Radioactive waste gas;

(a) drain lines from gas decay tanks,

(b) relief lines from gas decay tanks,

(c) Unit 2 tie-ins until these lines come into service,

(4) Off-gas;

(a) calibration lines to H_2 analyzers,

(b) steam system portion,

(c) Unit 2 tie-ins until these lines come into service,

(5) Safety injection;

(a) refueling water storage tanks and associated piping,

(b) accumulator fill lines,

(c) leakoff lines from recirculation line isolation valve caps,

(6) Boric acid processing;

(7) Boron thermal regeneration;

(8) Unit 2 fuel pool cooling and cleanup tie-ins until such time as they become operational;

(9) Process radiation monitoring;

(10) Process sampling except for;

(a) pressurizer steam and liquid sample lines, reactor coolant sample lines and residual heat removal heat exchanger sample lines,

(b) chemical and volume control system demineralizer outlet sample line,

(c) letdown heat exchanger sample line,

(11) Reactor building equipment drains except for a line which extends from the reactor coolant drain tank to the waste gas compressor;

(12) Reactor building floor drains;

(13) Primary containment purge line;

(14) Auxiliary building equipment drains and floor drains except for casing drain lines from:

(a) containment spray pumps,

(b) safety injection pumps,

(c) residual heat removal pumps, and

(d) chemical and volume control pumps,

(15) Solid radwaste disposal; and

(16) Chemical radwaste disposal.

In addition to the leak reduction program, the applicant has stated that all Class 1, 2 and 3 systems will be leak tested at prescribed intervals, in accordance with the requirements of the 1980 Edition, with addenda through the Winter of 1981 Addenda, of Section XI of the ASME Boiler and Pressure Vessel Code, "Rules for Inservice Inspection of Nuclear Power Plant Components," as described by Byron Station's "Inservice Inspection and Testing Program Plan." Portions of Class 1, 2 and 3 systems excluded from this leakage program will be leak tested through the Inservice Inspection Program.

The applicant has committed to documenting leakage observed during the performance of inservice tests and to preparing a work request to repair this leakage. Work requests of this type will be assigned a high priority by the applicant and designated as an ALARA concern. A review for possible modification to reduce leakage in the future will be initiated.

Piping and components which make up the containment penetrations will be tested every outage as part of the 10 CFR 50, Appendix J leakage testing program for Type A and Type B testing. Type C testing will be in accordance with the Technical Specifications.

9.3.5.2 Evaluation and Findings

The staff has reviewed the applicant's leak reduction program. The program as presented meets the requirements of TMI Action Item III.D.1.1 except that

initial leak-test results have not been provided. With their submittal, the program will conform to III.D.1.1.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection Program

9.5.1.1 General

Fire protection site audits were conducted between July 12-15, December 21-23 and December 27-30, 1983. As a result, several determinations were made regarding the adequacy of the fire protection program. In addition, a number of concerns/questions were expressed pertaining to previous applicant commitments; the justification for particular fire protection designs; and the degree of compliance with the fire protection criteria.

By letters dated September 20 and December 14, 1983, June 20, July 6, August 20, 1984, October 11, 1984, October 15, 1984, and Amendments No. 3 and 4 to the Byron Fire Protection Report, the applicant provided additional information.

9.5.1.4 General Plant Guidelines

Building Design

In the original SER, the staff evaluated the construction of fire area boundaries. During the inspections, the staff observed that in several areas of the plant, structural steel forming a part of or supporting fire barriers was unprotected. There was a concern that a fire could produce elevated room temperatures sufficiently high to cause the failure of such elements, resulting in the loss of integrity of the fire barrier and damage to components/cables of redundant shutdown divisions located within the same floor elevation or on vertically adjoining elevations.

By letter dated August 20, 1984, the applicant identified the location of all safety-related areas where unprotected steel structural elements exist, and provided the results of an analysis on the consequences of the failure by fire of those elements, and on the ability to safely shutdown the plant. In those areas where the failure of structural steel might have caused the loss of redundant shutdown divisions, the applicant committed to protect the steel with a listed "fireproofing" material that is rated at 2 hours as defined by the test method of ASTM E-119. This protection is commensurate with the hazard in these locations with conservative margin and provides the staff with reasonable assurance that the steel will retain its integrity until any exposure fire is suppressed by the plant fire brigade. In those areas where failure of structural steel would not result in damage to redundant shutdown divisions, the steel is not coated with a fireproofing material. Because the failure of such steel has no safety consequences, the staff finds this acceptable. The staff, therefore, concludes that the lack of protection of structural steel in certain areas represents an acceptable deviation from the guidelines of Section C.5.a.(1) of BTP CMEB 9.5-1.

During the inspections, the staff observed that the installation of fireproofing for some structural steel elements was incomplete. By letter dated September 20, 1983, the applicant committed to complete most of this work

prior to exceeding 5% power. Completion of this work prior to low power operation is not necessary because only small quantites of radionuclide inventory will exist in the reactor coolant system and therefore will not affect the health and safety of the public. Where protection of structural steel is incomplete, the applicant committed to implement the action statements of the technical specifications. With the implementation of this commitment, this aspect of the fire protection program will conform to the guidelines in Section C.5.a. of BTP CMEB 9.5-1 and is, therefore, acceptable. The staff also observed several locations within the Auxiliary Building where floor/ceiling structural assemblies such as at open stairways were not completely fire rated. There was a concern that if a fire occurred on one elevation, smoke, flame and hot gases would propagate upward and damage redundant shutdown systems in vertically adjoining fire zones. In Amendment No. 3 to the Fire Protection Report, the applicant identified all locations where such physical features exist and proposed specific fire protection modifications to protect at least one shutdown division. In some locations, such as between elevations 346 feet and 364 feet in the Auxiliary Building, the applicant committed to install an automatic sprinkler system around the unprotected openings. This protection, coupled with the remaining fire rated floor construction and sealed penetrations, provides the staff with reasonable assurance that the effects of a fire will be largely confined to one elevation and, therefore, one division will remain free of fire damage.

In other locations where protection of floor openings was not practicable, such as in the floor between elevations 364 feet and 383 feet of the Auxiliary Building, the applicant committed, in Amendment 3, to protect one shutdown division by either a 1-hour fire-rated barrier or a 3-hour rated barrier where signficant quantities of combustibles were present. Therefore, if vertical fire propagation occurred, one shutdown division would be free of damage.

In the remaining areas where complete, fire-rated floor/ceiling assemblies were not provided, the fire hazards are negligible and any combustible material is widely dispersed. The areas are completely protected by an automatic fire detection system, partial fire suppression systems over significant hazards, and portable fire extinguishers and manual hose stations. Openings in the floor/ceiling are protected by noncombustible seals and hatches such that a continuous barrier exists between redundant divisions (such as between elevations 414 feet and 426 feet in the Auxiliary Building). The staff therefore, has reasonable assurance that until fire extinguishment is provided, the floor/ceiling assembly will confine the fire effects so that one shutdown division remains free of damage. The staff therefore, concludes that the absence of continuous, 3-hour fire-rated barriers between vertically adjoining fire areas, as delineated in Amendment No. 3 to the Fire Protection Report is an acceptable deviation from the guidelines in Section C.5.a.(1) of BTP CMEB 9.5-1.

By Amendment No. 3 to the Fire Protection Report, the applicant committed to seal fire barrier penetrations with material having a fire resistance rating comparable to the ratings of fire walls and floor/ceiling assemblies. This necessitates that sealant material be installed to an appropriate depth consistent with its U.L. listing. During the site audit, the staff observed that sealant material was installed in the plant in thicknesses greater than the depth of the fire barrier. There was a concern that with the sealant material in this configuration, the fire rating of the penetration seals as installed in the plant, are not equivalant to the rating of the structural assembly.

Although the sealant is installed in greater thickness than the fire barrier, this thickness is necessary to achieve the required fire rating. The material is installed in a metal sleeve which is not prone to fire damage and will assure that the material stays in place until subjected to elevated temperatures in a fire. This configuration was tested in accordance with the test method in IEEE Standard 634. This test demonstrated that the seal would prevent fire propagation for 3-hours when exposed to an ASTM E-119 fire exposure. Therefore, the staff concludes that the installation of the penetration seal in this configuration is acceptable.

In addition, there was a concern that the acceptance criteria for the penetration qualification test was in excess of the 325°F maximum temperature permitted on the unexposed side by ASTM E-119, "Fire Test of Building Construction and Materials." The applicant stated that the acceptance criterion used was a maximum temperature rise on the unexposed surface of the fire stop of 325°F and that the maximum temperature rise on the unexposed side on the outer cable covering was 700°F. Actual fire test results conducted on the penetration seals demonstrated that the 325°F temperature criterion was exceeded on the unexposed side in a narrow zone along the penetration. The staff confirmed in a plant walkdown that no sensitive electronic components or combustible material exist in this zone. Therefore, the staff has reasonable assurance that conductive heat, smoke and hot gases will not be transmitted through the penetration assembly and damage shutdown-related systems on the unexposed side of the fire barrier.

During the site audit, the staff observed that the installation of some penetration seals was incomplete. By letter dated September 20, 1983, the applicant committed to complete most of this work by fuel load. Where the installation of seals is incomplete, the applicant has committed to implement the action statement of the technical specifications. With the implementation of this commitment, this aspect of the fire protection program will conform to the guidelines in Section C.5.a of BTP CMEB 9.5-1 and is, therefore, acceptable.

During the audit, the staff observed that bus ducts pass through certain fire barriers which separate redundant shutdown-related systems. There was concern that in the event of a fire of significant magnitude, the bus ducts would fail, causing fire to propagate to adjoining plant locations and damage both shutdown divisions. However, by letter dated December 14, 1984, the applicant committed to install a fire-rated sealant within bus ducts at the point where they penetrate walls which separate redundant shutdown divisions. The rating of the sealant will be equal to the fire rating of the wall it protects. This protection provides the staff with reasonable assurance that fire-propagation through the bus ducts will not occur, and, therefore, is acceptable.

In the Fire Protection Report, the applicant described the doors that are provided for access through fire barriers. Certain doors are Underwriters Laboratories (U.L) listed. Others are not listed because the particular configuration found in the plant has not been subjected to a standard fire test. However, these doors are constructed of the same materials and to the same standards as the listed doors and the installation of the door assembly in the fire barrier is identical to U.L. listed doors. The deviations from tested configuration were the result of modifications made to satisfy other regulatory guidance, such as plant security. It is the staff's opinion that these modifications

will not significantly diminish the fire resistance of these doors. During the site audit, the staff observed no unmitigated fire hazard that would result in the loss of integrity of the door during a fire exposure. The staff therefore concludes that the absence of a U.L. listing on those doors identified in the applicant's Fire Protection Report is an acceptable deviation from the guidelines in Section C.5.a.(5) of BTP CMEB 9.5-1.

During the audit, the staff observed that the door for the Auxiliary Feedwater Pump Room on elevation 383 feet did not have a U.L. label and was concerned that it was not listed. By letter dated September 20, 1983, the applicant confirmed that this was a U.L. listed door. This door is in conformance with the guidelines and is, therefore, acceptable.

Safe Shutdown Capability

NRC inspections of the Byron Station, Unit 1 identified several concerns regarding compliance with the fire protection and post-fire safe shutdown criteria. In response to the fire protection inspections, the applicant by letter dated June 28, 1984 provided Amendment 3 to the Fire Protection Report. Amendment 3 included a revised safe shutdown analysis which reflects as-built conditions for the plant. Additional information regarding Byron's safe shutdown capability was provided by letters dated July, 1984 which provided Amendment 4 to the Fire Protection Report; August 2, 1984; August 20, 1984; October 11, 1984; and October 15, 1984.

By Amendment 3 to the Fire Protection Report, the applicant revised the list of equipment necessary for post-fire safe shutdown of the plant. For hot standby, at least one train of the following systems would be available: (1) the charging system utilizing the refueling water storage tank; (2) the auxiliary feedwater system including the condensate storage tank, the steam generator safety valves, and the steam generator atmospheric relief valves; (3) the emergency diesel generators and essential switchgear; (4) the essential service water system including cooling tower fans; (5) instrumentation including pressurizer pressure and level, reactor coolant temperatures, and steam generator pressure and level indications; and (6) various support components including essential ventilation components. These systems in conjunction with at least one train of the following systems would be utilized for plant cooldown to cold shutdown: (1) the residual heat removal system and (2) the component cooling water system.

The applicant performed a cable separation study as part of the safe shutdown analysis to ensure the post-fire availability of at least one train of the above identified systems. Power, control and instrumentation cables were identified for the post-fire shutdown systems. The computerized cable tray data base for all cables of the Byron plant was utilized to correlate fire zones and cable routing. For each fire zone, a list of safe shutdown cables was generated. Conduit routings were manually added to the fire zone list.

For fire zones containing redundant equipment or cabling, the applicant verified that adequate fire protection measures, adequate repair capability, or alternative shutdown capability existed. Repair activities consist of installation of temporary cables for various components of the residual heat removal systems. No repairs are needed for components to achieve post-fire hot standby

conditions. All repair material is stored onsite, and procedures are in place to affect necessary repairs.

Alternative shutdown capability in part, consists of local operation of equipment if the fire results in loss of redundant control capability. Local operations include local start and control of pumps and manual operation of valves and circuit breakers. For all local operation, accessibility of components and time restrictions were considered. These local operations are addressed in various plant procedures. Alternative shutdown capability also consists of utilization of diverse equipment as follows. To monitor reactor coolant hot leg temperature, the applicant ensured the availability of one of the following components, all of which provide an indication of hot leg temperature: reactor coolant wide range hot leg RTD's, core exit thermocouples, or heated junction thermocouples. Alternative shutdown capability also includes use of remote shutdown and instrument panels as discussed below.

The applicant also considered associated circuits by verifying that fire-induced failures in cabling for equipment not required for achieving safe shutdown would not adversely impact safe shutdown. The applicant verified that adequate coordinated circuit protection exists to ensure availability of power supplies necessary for post-fire safe shutdown. Further, the electrical design of the plant ensures that associated cables of redundant divisions do not share common enclosures (cable tray, conduit or raceway).

The applicant also performed a detailed analysis of circuits whose fire-induced spurious operation could adversely impact safe shutdown. This analysis included a review of high-low pressure interfaces. For each fire zone, the applicant's analysis assumed all equipment and circuits located in the fire zone were unavailable and one spurious actuation resulted from the fire. The applicant's analysis demonstrated that through the fail-safe design of air-operated valves or with manual operation of components, post-fire safe shutdown would not be adversely impacted. For the high-low pressure interface of the RHR pump suction lines, the applicant demonstrated that adequate separation of the valve control circuits and pressure interlock circuits existed to ensure one valve of the redundant valves in series would not spuriously operate due to fire-damage in any one fire area. For the concern of spurious operation of the pressurizer PORV's, the applicant has committed to prevent or mitigate the spurious operation of these valves by either 1) isolating the valves prior to an occurrence of a fire, 2) providing electrical isolation or 3) providing a means to detect and defeat any spurious operations.

Based on the above, the staff concludes that the post-fire safe shutdown capability for Byron complies with the guidelines of SRP Section 9.5.1, Position C.6.b subject to the following condition: "The applicant shall complete the analysis of spurious operation of the pressurizer PORV's and fully implement any necessary modifications prior to exceeding 5% power."

The staff has determined an exemption is required from GDC-3 of Appendix A, which requires that systems and components important to safety be designed to minimize the effect of fires. Due to the low decay heat and fission products in the core at power levels up to 5%, there is sufficient time for operator response to isolate the PORV's. Therefore, the staff concludes that the exemption from GDC-3 up to 5% power will not endanger life or property or the common defense and security and is otherwise in the public interest.

Alternative Shutdown Capability

Section 7.4.1 of the Final Safety Analysis Report (FSAR) describes the remote shutdown panels' design and capability. The design objective of the remote shutdown panels is to provide a central point to control and monitor plant shutdown independent of the control room in the event of an evacuation of the control room. The design of the panels includes the capability to electrically isolate the instrumentation indications and control functions for the shutdown systems from the control room. The auxiliary feedwater system, main steam atmospheric relief valves, and chemical and volume control system (charging pump and letdown line) can be manually controlled from the panels to achieve and maintain hot shutdown independent of the control room. Initiation of the residual heat removal system for achieving cold shutdown is performed at local locations. Support system functions are initiated either at the remote shutdown panels or at local locations.

The design of the remote shutdown system was reviewed to determine compliance with the criteria of SRP Section 9.5.1, Position C.5.c. Reactivity control is accomplished by a manual scram before the operator leaves the control room and boron addition via the chemical and volume control system (charging pumps) utilizing the refueling water storage tank. Reactor coolant makeup is also provided by the charging portion of the chemical and volume control system. Reactor decay heat removal in hot shutdown is provided through the steam generator by the auxiliary feedwater system and main steam atmospheric relief valves, and in cold shutdown by the residual heat removal system, component cooling water system, and essential service water system. Cold shutdown can be achieved within 72 hours following a fire in any plant area.

In addition, the applicant has committed to install a "Fire Hazards Panel". The "Fire Hazards Panel" will contain indication for two channels each of steam generator level and pressure, one channel each of pressurizer pressure and level, four channels each of reactor coolant hot and cold temperature, and one channel of source range neutron flux. The instrumentation and cabling for the "Fire Hazards Panel" will be independent (physically and electrically) of the control room and auxiliary electric equipment room. The design of the panel will utilize replacement of existing reactor coolant hot and cold temperature elements with duel element models. The cables associated with the second element will be routed such that a fire could not disable all temperature indication.

The applicant, in its October 26, 1984 letter, has committed to install the panel and associated modifications prior to exceeding 5% power. In the interim, the applicant will institute a roving fire watch (hourly) in the auxiliary electrical equipment room.

Based on the above, the staff concludes that the alternative shutdown capability complies with the guidelines of SRP Section 9.5.1, Position C.6.c and is, therefore, acceptable subject to the following condition:

> Prior to exceeding 5% power, the applicant shall provide the fire hazards panel and associated instrumentation modifications.

The staff has determined that an exemption is required from GDC-3 of Appendix A, which requires that systems and components important to safety be designed to minimize the effect of fires. Based on the roving fire watch in the auxiliary

electrical equipment room until the fire hazards panel is provided, the staff concludes that the exemption from GDC 3 up to 5% power will not endanger life or property or the common defense and security and is otherwise in the public interest.

The applicant requested three deviations from the guidelines of BTP CMEB 9.5-1 in the area of safety shutdown capability and alternate shutdown capability.

In Amendment 3, the applicant requested a deviation (No. C.1) from the criteria of SRP Section 9.5.1 regarding separation of redundant pressurizer PORV and block valve cables. The applicant indicated that loss of control capability for these valves would not adversely impact safe shutdown. For hot standby, pressurizer overpressure protection would be provided by the pressurizer safety valves. For cold shutdown, primary cooldown and depressurization would be achieved by utilizing the steam generators to remove decay heat in conjunction with the letdown system. Sufficient cooldown and depressurization can be accomplished to allow initiation of the residual heat removal system. Spurious operation of the pressurizer PORV is addressed in the safe shutdown portion of this SER. Based on the above, the staff concludes that the applicant's proposed shutdown capability is acceptable.

In Amendment 3, the applicant requested deviation (No. C.6) from the criteria of SRP Section 9.5.1 regarding separation of redundant reactor coolant cold leg temperature instrumentation. The applicant has committed to modify the cold leg temperature detectors with duel element models. The second element will be separated from the redundant component in accordance with the criteria of SRP Section 9.5.1. In the interim, the applicant will utilize steam generator pressure to infer cold leg temperature. In addition, at least one channel of each of the following instruments will be available: reactor coolant hot leg temperature, steam generator pressure and level, and pressurizer pressure and level. Based on the above, the staff concludes that the applicant's interim measures are acceptable.

In Amendment 3, the applicant requested a deviation (No. C.7) from the criteria of SRP Section 9.5.1 regarding separation of redundant reactor coolant hot leg temperature instrumentation. The applicant has committed to modify the hot leg temperature detectors with duel element models. The second element will be separated from the redundant component in accordance with the criteria of SRP Section 9.5.1. In the interim, the applicant will utilize incore thermocouples to infer hot leg temperature. In addition, at least one channel of each of the following instruments will be available: reactor coolant cold leg temperature, steam generator pressure and level, and pressurizer pressure and level. Based on the above, the staff concludes that the applicant's interim measures are acceptable.

Control of Combustibles

In the original SER, there was a concern that the protection of hydrogen lines in safety related areas would not meet the guidelines of Section C.5.d.(2) of BTP CMEB 9.5-1. However, in the Fire Protection Report the applicant committed to comply with these guidelines. An excess flow valve has been provided at the hydrogen gas storage facility, designed to limit hydrogen concentrations in areas affected by a line break not to exceed 2 percent. Also, the 1-inch hydrogen supply pipe that is routed through the Auxiliary Building is designed to seismic Category 1 requirements between the Volume Control Tank and the control

valve, and is seismically supported throughout the building. This protection conforms with the above referenced guidelines and is, therefore, acceptable.

During the site audit, the staff observed several locations in the Auxiliary Building where seismic supports were incomplete. By letter dated September 20, 1983, the applicant confirmed that this work is now complete. This item is considered closed.

Ventilation

During the site audit, the staff observed that several fire dampers were installed in a "ganged" configuration, such as in the diesel generator room exhaust ducts. There was concern that this configuration is not consistent with the listing of the damper by U.L. By letters dated September 20 and December 14, 1983, the applicant confirmed that no individual damper in a ganged configuration has dimensions greater than the largest damper tested and listed by U.L. This is consistent with the staff guidelines, and therefore is acceptable.

Lighting and Communication

During the inspection, the staff discovered 8-hour battery powered emergency lighting units were not provided per Section C.5.h.(1) of BTP CMEB 9.5-1 in areas where safe shutdown functions are to be performed, and their access paths. By letters dated September 20, 1983, June 20, 1984 and in Amendment No. 3 to the Fire Protection Report, the applicant committed to install additional 3-hour battery powered lighting units. All areas where manual shutdown related activities are to be performed were delineated. Travel routes to these areas were also identified. 8-hour battery powered lighting units were provided for these locations. A plant walkdown was then conducted by the station technical staff to confirm that the level of illumination was sufficient to perform the shutdown function. The above analysis and related modifications provides the staff with reasonable assurance that adequate emergency lighting is available and is, therefore, acceptable.

In the orignal SER, the location of the repeaters used in conjunction with the emergency radio system was not resolved. There was a concern that redundant repeaters would be located in close proximity to one another, and would both be lost during a single fire event. By letter dated June 17, 1983, the licensee committed to provide a third repeater, located remote from the original two. During the site audit, the staff confirmed that the third repeater was located so as not to be damaged by a single fire event. However, the installation of the repeater was not complete. By letter dated September 20, 1983, the applicant confirmed that the work had been completed. Based on this information, this item is now considered resolved.

Fire Detection and Suppression

During the inspections, the staff observed that in some locations the detection systems were adversely affected by features such as physical obstructions, air pockets, and high room ventilation rates. There was a concern that because of these features individual fire detections would not function as designed, resulting in delayed alarm and fire suppression. In Amendment No. 4 to the Fire Protection Report, the applicant provided the results of a complete reanalysis of the fire detection system to the guidelines of NFPA Standard No. 72E. Where

items of nonconformance were observed, the applicant committed to install additional detectors or to modify the system to bring it into conformance. With the implementation of these commitments, the fire detection system will be in conformance with NFPA Standard No. 72E, and Section C.6.a.(3) of BTP CMEB 9.5-1, and is, therefore, acceptable.

Fire Protection Water Supply System

During the site audit, the staff observed that the installation of the electric motor driven fire pump did not comply with NFPA Standard No. 20, which is not consistent with the applicant's commitments in the Fire Protection Report. In Amendment No. 4 to the Fire Protection Report, the applicant provided the results of a complete re-analysis of the fire pumps and related equipment to NFPA 20. With the following two exceptions, the applicant committed to modify the design to bring it into compliance. The work will be done before exceeding 5% power. Implementation of the modifications, described in Amendment No. 4, before low power operation is not necessary because only small quantities of radionuclide inventory will exist in the reactor coolant system and, therefore, will not affect the health and safety of the public.

1. The low voltage control circuit for the pump controller will not be supplied from a stepdown control circuit transformer as specified by NFPA 20. The applicant's design has the control circuit powered from the plant 125V DC system. It is the staff's opinion that this design is more reliable because the source is safety-related.

2. A pilot light will not be provided on the controller to indicate that power is available, as stipulated by NFPA 20. This deviation is acceptable because there are visual alarms for pump running, failure to start, and loss of power transmitted and annunciated in the main control room.

The staff, therefore, concludes that the above described controller design features are an acceptable deviation from Section C.6.b.(6) of BTP CMEB 9.5-1.

During the site audit, the staff observed that a required sectional control valve located at the discharge header of the fire pumps had not been installed. The absence of this valve would adversely affect fire protection during periodic testing of the pumps. By letter dated September 20, 1983, the applicant confirmed that this valve was now in place. The staff consider this item resolved.

Water Suppression and Hose Standpipe Systems

During the site audit, the staff observed that the manual discharge valves for the water-deluge fire suppression systems protecting charcoal filters is located in close proximity to the filters. Because of this feature and the limited access in the area, there was a concern that if a fire occurred in the filters, the resulting high temperatures would prevent access to the valves. However, if a fire should occur, the high temperature alarms are expected to activate and annunciate in the control room, enabling the fire brigade to arrive before significant fire propagation and heat generation occurred. Also, by letter dated December 14, 1983, the applicant committed to develop a pre-fire strategy for these areas to alert the fire brigade as to the location of the valves. Operating personnel will utilize existing manual hose lines and discharge water to cool down the area and to shield the brigade members. These actions provide

the staff with reasonable assurance that the valves for the suppression system can be reached and activated in the event of a fire in the filters. The staff, therefore, finds this condition acceptable.

In the Fire Protection Report, the applicant committed to comply with NFPA Standard No. 13 in the design and installation of automatic sprinkler systems. During the site audit, the staff observed that the ceiling-level sprinklers over the lube oil drain tank were obstructed. By letter dated September 20, 1983, the applicant committed to provide additional sprinkler heads under the obstructions so as to provide complete sprinkler protection for the oil drain tank area. This work will be completed by fuel load. The staff finds this acceptable.

During the site audit, the staff observed that the present location of hose stations would not permit a hose stream to reach all areas of the computer room, cable riser area and battery room on elevation 451 feet. The staff also observed that because of the congested conditions in certain plant areas, such as the cable spreading rooms, it would not be possible to utilize hose streams because of the inability to fully deploy the woven-jacketed fire hose. By letters dated September 20, 1983 and July 6, 1984, the applicant committed to relocate an existing hose station to provide complete coverage for the above referenced areas. Also, in the September 20, 1983 letter, the applicant committed to replace existing woven-jacket fire hose in the upper and lower cable spreading rooms with a hard rubber-type hose. This work will be done by fuel load. The staff find this acceptable.

In the Fire Protection Report, the applicant committed to install the standpipe system in accordance with NFPA Standard No. 14. Section 4-4.2 of this standard requires an approved pressure reducing device where standpipe outlet pressures exceed 100 pounds per square inch (psi). At Byron Station, outlet pressures exceed 100 psi. However, the fire brigade is trained in handling hose lines with nozzle pressures up to 200 psi. In addition, wherever outlet pressures exceeds 150 psi, a caution notice is posted. Because the brigade is trained with higher nozzle pressures; because high pressures on the water distribution system are necessary to support sprinkler system demand; and because the applicant has located sensitive electrical components such that redundant shutdown systems will not be inadvertently damage by water from the hose streams; the staff concludes that the lack of pressure reducers is an acceptable deviation from Section C.6.c.(4) of BTP CMEB 9.5-1.

During the inspection, the staff observed that the installation of fire hose nozzles, hose houses and other manual fire fighting equipment was incomplete. By letter dated September 20, 1983, the applicant committed to complete the installation of this equipment by fuel load. This is in accordance with the staff's guidelines and is, therefore, acceptable.

9.5.1.5 Fire Protection For Specific Plant Areas

Primary Containment

In the Fire Protection Report, the applicant requested approval for several deviations from the guidelines of Section C.5.6.(2) to the extent that it requires redundant shutdown divisions to be separated by 20 feet, free of intervening combustibles. Shutdown divisions not conforming to the separation

criteria are physically separated within containment and outside of the pressurizer cubicles by a horizontal distance of 20 feet or more, with the presence of intervening combustible materials. The intervening combustibles consist of a limited quantity of IEEE 383 qualified cable. The amount of combustible material within containment varies depending on the elevation. Existing fire protection includes ionization-type smoke detectors, manual hose stations; and portable fire extinguishers. Because the combustibles are widely dispersed and sources of ignition are limited, the staff does not expect a fire of significant magnitude or duration to occur. Smoke and hot gases from a postulated fire would be dissipated and cooled through the large open areas of containment. It is the staff's judgment that, under these conditions, a fire would, at most, cause damage to systems from one shutdown division, but would not be able to propagate horizontally and damage the redundant division before self extinguishing or being suppressed by the plant fire brigade. Therefore, the presence of intervening combustible materials within containment is an acceptable deviation from Section C.5.6(2) of BTP CMEB 9.5-1.

For those systems identified in the Fire Protection Report which do not meet the separation criteria, a procedure exists which will enable operators to safely shutdown the plant in the event that a fire in containment causes the loss of redundant divisions. This conforms with the guidelines of Section C.5.c of BTP CMEB 9.5-1 and is, therefore, acceptable.

In the original SER, the provision of an oil collection system for the reactor coolant pumps was an unresolved issue. In the Fire Protection Report and by letter dated August 20, 1984, the applicant committed to install an oil collection system capable of collecting lube oil from all potential pressurized and unpressurized leakage sites and to channel the oil from all four pumps to a vented and closed container. The system is designed and installed such that any failure will not lead to a fire during normal or design basis accident conditions, including the safe shutdown earthquake. This commitment satisfies the guidelines contained in Section C.7.a of BTP CMEB 9.5-1 and is, therefore, acceptable.

Control Room Complex

In the August 16, 1982 revision to the Fire Protection Report, the applicant comitted to comply with Section C.5.d of BTP CMEB 9.5-1 and with Section C.7.b, with the exception that an automatic fire suppression system will not be installed in "offices" in the control room complex. The staff observed that the computer related storage areas adjacent to the control room are not equipped with an automatic fire suppression system, which is not consistent with these commitments. By letter dated December 14, 1983, the applicant stated that the combustible loading in these rooms has been reduced. Fire Zone 2.1-1 (formerly a record storage room) is utilized as an office with a fire load of about 42,300 BTU/ft^2. The other area, Fire Zone 2.1-2 (formerly record storage and toilet room) is used to store paper for control room recorders and has a fire load of about 43,900 BTU/ft^2. Because of the reduced fire hazard and the existing fire protection, which includes automatic fire detection and manual fire fighting equipment, the original conclusion that an acceptable level of fire protection has been provided in these areas is still valid.

The August 16, 1982 revision to the Fire Protection Report identifies equipment located within the Control Room Refrigeration Equipment Rooms being necessary for safe shutdown. There was a concern that if a fire occurred in these rooms, safe shutdown would not be able to be achieved and maintained. By letter dated September 20, 1983, the applicant provided the results of a reassessment of the systems in these rooms. On the basis of this reassessment, the applicant's Fire Protection Report was amended to indicate that this equipment was not necessary for safe shutdown. Because safe shutdown will not be affected by a fire in these rooms, the staff finds that the existing level of fire safety is acceptable.

Automatic smoke dampers that close upon operation of a detection system are not provided in the control room vent ducts. Instead, two 1-1/2-hr-rated fire dampers in series, outside smoke detectors, and motorized isolation dampers are provided. If a fire occurs adjacent to the control room, the installed early warning detection system would provide advance notice of the incipient fire conditions and fire fighting activities would serve to limit the size of the fire. In the event smoke enters the control room before the isolation dampers can be closed, the operators are provided with self-contained breathing apparatus. Because of this, the staff finds this to be an acceptable deviation from its guidelines.

Fire detectors are not provided within all the control room cabinets. Detectors are provided in the main control console, in the vents of the cabinets and at the ceiling of the control room. This level of detection, along with the constant attendance in the control room, provides the staff with reasonable assurance that a fire, if one should occur, would be detected in its incipient stages. Therefore, the absence of detectors in each control room cabinet is an acceptable deviation from Section C.7.b of BTP CMEB 9.5-1.

Carpeting is installed on the floor of the control room. There was a concern that the carpet might represent a fire hazard, if ignited. However, the carpet has been tested in accordance with ASTM E-84. The results of the test demonstrate that the carpet has a flame spread rating of 25. On this basis, guidelines consider this material as noncombustible. The staff, therefore, find that the carpet in the control room is acceptable.

Cable Spreading Room

In the original SER, the fire protection for the cable spreading rooms was not resolved. The applicant proposed to install an automatic halon fire suppression system and a manual carbon dioxide fire suppression system for the upper cable spreading room and an automatic carbon dioxide fire suppression system for the lower cable spreading room. This represents a deviation from the staff's guidelines which calls for a water-type fire suppression system. There was a concern that this design would not be sufficiently reliable to provide reasonable assurance that a potential fire in these areas would be suppressed. However, by letter dated June 17, 1983, the applicant proposed measures which, in the staff's opinion, would significantly enhance system reliability and effectiveness. Specifically, the applicant committed to electrically supervise all interior doors in the cable spreading rooms and to emphasize in the training of the fire brigade that the doors into these areas should remain closed. These measures along with the existing construction of the perimeter walls

and floor/ceilings will provide the staff with reasonable assurance that extinguishing gas concentrations will be maintained. Also, additional detectors will be added to provide two separate detection circuits for the halon system and a second train of actuation logic will be added in parallel to the existing logic train. The existing Halon bottle discharge valve actuators will be replaced with a pair of pilot valves, each connected to one of the two trains of actuation logic, and either of which can actuate the Halon bottle discharge valve. An additional halon storage bottle has been provided to add redundance to the halon supply. Subsequently, there was a concern that the design of the CO_2 systems for the lower cable spreading room was not sufficiently redundant to preclude single failures from adversely affecting the automatic fire suppression capability. By letter dated September 19, 1984, the applicant committed to install redundant valves at the carbon dioxide storage tank and lower cable spreading room zone discharge valves. The installation of these valves will be complete prior to exceeding 5% power. These modifications will not be necessary prior to low power operation because only small quantities of radionuclide inventory wll exist in the reactor coolant system and, therefore, will not affect the health and safety of the public. The design and installation will be in accordance with NFPA 12. These valves are intended to be used to activate the CO_2 systems in the lower cable spreading room zones in the event of a failure of the normal tank or zone dischage valves. The Pre-Fire Plan strategies have been modified to include the use of this additional backup capability, if required. These measures mitigate the concern that a single failure could render the halon and CO_2 systems inoperable. There was also a concern that during periodic maintenance in the cable spreading rooms, the gaseous fire suppression systems would be deactivated and could not readily be reactivated in the event of a fire. However, the design of the systems is such that if it becomes necessary to discharge carbon dioxide into the cable spreading rooms because of a fire, this can be accomplished manually without need of any special tool or device. The staff, therefore, concludes that because of the above referenced modifications, the separation of redundant shutdown divisions into separate cable spreading rooms and the existing fire protection for these rooms as detailed in the Fire Protection Report, the lack of a water-type fire suppression system is an acceptable deviation from Section C.7.c of BTP CMEB 9.5-1.

The staff has determined that an exemption is required from GDC-3 to Appendix A, which requires that systems and components important to safety be designed to minimize the effect of fires. As mentioned above, the modifications to the CO_2 system for the lower cable spreading can be deferred to up to 5% power because of the small quantities of radionuclides inventory in the reactor coolant system. Therefore, the staff concludes that the exemption from GDC-3 up to 5% power will not endanger life or property or the common defense and security and is otherwise in the public interest.

In Amendment No. 3 to the Fire Protection Report, the applicant indicated that one of the "sub-areas" in the upper cable spreading room has only one access door. However, the other sub-areas have at least two doorways and access for fire brigade operations is unrestricted. Because of this and the availability of automatic fire suppression systems, the staff consider this condition acceptable.

Battery Rooms

During the inspection, the staff observed that the batteries were not separated from other areas of the plant by 3-hour fire rated barriers and "explosion-proof" lighting fixtures had not been installed in the battery room. There was a concern that the absence of a wall would adversely affect the ventilation system, resulting in an explosive mixture of hydrogen gas in air, which could be ignited by the non-explosion-proof electric fixtures. By letter dated July 6, 1984, the applicant committed to install a 2-hour fire-rated wall between the batteries and the remaining electrical equipment in the battery room. This work will be done by fuel load. With this modification, the existing ventilation system will be able to limit hydrogen gas concentration so as not to exceed 2 percent. The safety-related battery rooms now comply with the guidelines in Section C.7.g. of BTP CMEB 9.5-1 and are, therefore, acceptable.

Diesel Generator Areas

In the August 16, 1982 revision to the Fire Protection Report, the applicant committed to comply with Section C.5.d(1), "Control of Combustibles" of BTP CMEB 9.5-1. In the diesel generator rooms and at the Auxiliary Fuel Pump Room, the staff observed that curbs were not provided at doorways into these areas and was concerned that a potential exists for a diesel fuel fire to propagate through the doorway into adjoining areas. However, by letter dated September 20, 1983, the applicant provided the results of a re-analysis of this potential problem in the above two areas. The applicant concluded that because of the existing floor drain capacity, embedded piping, curbing at the fuel oil day tank enclosure and control room alarm, the existing safeguards are sufficient to preclude a hazardous accumulation of fuel oil. The staff has reviewed this analysis and agrees with the applicant that the above measures are sufficient to satisfy the guidelines contained in the above referenced section of BTP CMEB 9.5-1. This item is now considered resolved.

The cooling water lines for diesel generator 1A are routed through the room containing generator 1B. This represents a deviation from the guidelines because the 1A cooling water lines are not protected as stipulated in Section C.5.b.(2) of BTP CMEB 9.5-1. However, because of the complete, area wide, automatic fire detection and suppression systems; the steel pipe construction and the insulation for the cooling water pipes in the diesel generator rooms, a fire in Room 1B will not damage cooling water pipes for both diesel generators before being detected and extinguished. Therefore, the routing of cooling water lines for diesel generator 1A through the room containing diesel generator 1B is an acceptable deviation from the above referenced guidelines.

Other Areas

In Amendment No. 3 to the Fire Protection Report and by letter dated August 20, 1984, the applicant requested approval for several deviations from the guidelines of Section C.6.b(2) of BTP CMEB 9.5-1, which pertain to the protection of redundant shutdown-related systems. Specifically, the applicant requested approval: 1) where redundant divisions are separated by a continuous fire barrier which is not completely 3-hour fire rated; 2) where redundant divisions are located more than 40 feet apart, with some combustibles in the intervening space or separated by a 1-hour fire barrier and the area is not completely protected by an automatic fire suppression system; and 3) where a fixed fire

suppression system is not installed in an area for which an alternate shutdown capability has been provided. These deviations are in addition to those previously reviewed in Sections 9.5.1.4 and 9.5.1.5 of this report.

In general, the plant locations where these deviations exist can be characterized by a low fire loading, with combustible material widely dispersed. If all of the combustibles were totally consumed, it would produce a fire of approximately 30 minute intensity as measured by the time-temperature curve of ASTM Standard E-119. However, such a worse-case event is not likely because of the available fire protection. In those locations where concentrated combustibles may be present, such as at the hatchways on elevation 364 feet of the Auxiliary Building, an automatic sprinkler system has been provided or one division of shutdown related cables have been protected by a 3-hour fire rated barrier. These areas also have large floor-to-ceiling heights and large room volumes which mean the effects of a fire, such as smoke and hot gases, will be dissipated. All of these locations have been provided with a complete smoke detection system which provides the staff with reasonable assurance that a potential fire will be detected in its early stages and suppressed manually by the fire brigade before significant propagation or damage occurs.

In several locations, such as on elevation 426 feet of the Auxiliary Building, masonry walls separate redundant shutdown divisions. The construction of these walls is such as to achieve at least a 3-hour fire rating. However, some unprotected penetrations exist which would allow smoke and hot gases to propagate from one area to an adjoining location. In Amendment No. 3, the applicant committed to seal these openings with a noncombustible material such as silicone foam which will prevent fire propagation. This provides reasonable assurance that products of combustion will not spread beyond the fire area before the arrival of the plant fire brigade.

In some locations, such as on elevation 346 feet of the Auxiliary Building, redundant divisions are separated by more than 110 feet. Because of this large distance and the existing fire protection, the staff has reasonable assurance that if a fire should occur at least one shutdown division would remain free of damage.

In other locations, such as on elevation 364 feet of the Auxiliary Building, separation of redundant divisions is approximately 45 feet. However, the space between divisions is protected by automatic sprinklers. Redundant components are separated by masonry walls. And one division of redundant cables is protected by a 1-hour fire-rated barrier. The staff, therefore, concludes that no additional protection is required to assure that one division will be available to achieve and maintain safe shutdown.

For those fire areas, such as the control room and remote shutdown panel area, where a fixed fire suppression system has not been provided, if a fire of significant magnitude occurs and damages both shutdown divisions, an alternate shutdown method is available which is outside of these locations. No loss of shutdown capability occurs and, therefore, a fixed fire suppression system is not necessary to achieve an acceptable level of fire safety.

The staff, therefore, concludes that the devisions identified in Amendment No. 3 to the Fire Protection Report, and the applicant's August 20, 1984 letter,

represent an acceptable level of safety to that achieved by literal compliance with Section C.6.b(2) of BTP CMEB 9.5-1.

During the site audit, the staff observed several discrepancies in the description of fire protection features in the applicant's Fire Protection Report from what was observed in the plant. Such discrepancies include the description of fire proofing for structural steel, the extent of fire detection in safety related plant areas, the nature of fire doors and the lack of a fire hazards analysis and fire protection for the "Med-Chem" area on elevation 401 feet. By letter dated September 9, 1984 and in Amendment No. 3 to the Fire Protection Report, the applicant corrected the discrepancies. The staff considers this issue resolved.

In Amendment No. 3, the applicant stated that for those areas which are not protected by a fixed fire suppression system, local fire alarms are not provided. However, the activation of the fire alarm and detection system will be annunciated audibly and visually in the control room. Upon receipt of an alarm, the control room operators have the capability, as described in other sections of the SER, to summon and direct the fire brigade and to initiate local evacuation, if necessary. The staff concludes that this capability exceeds the guidelines contained in Section C.7 of BTP CMEB 9.5-1 and is, therefore, acceptable.

In Amendment No. 4 to the Fire Protection Report and the October 11, 1984 letter, the applicant provided the results of a complete reassessment of the plant fire protection program to the guidelines contained in the following NFPA standards:

NFPA 10, Portable Fire Extinguishers
NFPA 11, Foam Systems
NFPA 12, Carbon Dioxide Fire Extinguishing Systems
NFPA 12A, Halon 1301 Fire Extinguishing Systems
NFPA 13, Sprinkler Systems
NFPA 14, Standpipe and Hose Systems
NFPA 15, Water Spray Systems
NFPA 16, Foam Water Systems
NFPA 20, Fire Pumps
NFPA 24, Fire Mains and Hydrants
NFPA 26, Valve Supervision
NFPA 27, Private Fire Brigades
NFPA 30, Flammable Liquids Code
NFPA 37, Combustion Engines
NFPA 50A, Gaseous Hydrogen Systems
NFPA 72D, Proprietary Protective Signaling Systems
NFPA 72E, Fire Detectors
NFPA 80, Fire Doors
NFPA 90A, Air Conditioning and Ventilation Systems

The applicant has identified some deviations from the above guidance. The applicant has committed to modify certain fire protection features so as to be in conformance with the referenced standards.

Modifications in safety related areas are to be complete before the plant exceeds 5% power. Implementation of these modifications is not necessary

prior to low power operation because only small quantities of radionuclide inventory will exist in the reactor coolant system and therefore will not affect the health and safety of the public. The staff, therefore, concludes that this represents an acceptable deviation from the guidelines in Section C.1.c(2) of BTP CMEB 9.5-1.

The staff has determined that an exemption is required from GDC-3 to Appendix A, which requires that systems, structures, and components important to safety be designed to minimize the effect of fires. As mentioned above, the modifications related to NFPA standards can be deferred up to 5% power because of the small quantities of radionuclide inventory in the reactor coolant system. Therefore, the staff concludes that the exemption from GDC-3 up to 5% power will not endanger life or property or the common defense and security and is otherwise in the public interest.

9.5.1.7 Conclusion

The technical requirements of Appendix R to 10 CFR 50 and Appendix A to ASB 9.5-1 have been included in BTP CMEB 9.5-1.

The following deviations from the guidelines of BTP CMEB 9.5-1 have been approved:

1. Protection of structural steel as described in Section 9.5.1.4.

2. Continuity of floor/ceiling assemblies as described in Section 9.5.1.4.

3. Acceptance criteria for fire barrier penetrations as described in Section 9.5.1.4.

4. Unlisted fire doors as described in Section 9.5.1.4.

5. Design of the fire pumps controller as described in Section 9.5.1.4.

6. Separation of redundant pressurizer PORV and block valve cables as described in Section 9.5.1.4.

7. Separation of redundant reactor coolant cold leg temperature instrumentation as described in Section 9.5.1.4.

8. Separation of redundant reactor coolant hot leg temperature instrumentation as described in Section 9.5.1.4.

9. Seismic design of the standpipe system as described in Section 9.5.1.5 of the SER.

10. Absence of pressure reducers for the standpipe system is described in Section 9.5.1.5.

11. Fire Protection for Containment as described in Section 9.5.1.5.

12. Fire Protection for the Control Room Complex as described in Section 9.5.1.5.

13. Fixed fire suppression systems in the Cable Spreading Rooms as described in Section 9.5.1.5.

14. The separation of cooling water lines for the diesel generators in Room 1B as described in Section 9.5.1.5.

15. Deviations from BTP CMEB 9.5-1 in other plant areas as described in Section 9.5.1.5.

16. Implementation of fire protection modifications as described in Section 9.5.1.5.

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

9.5.4.1 Emergency Diesel Engine Auxiliary Support Systems (General)

The original SER stated that the applicant had committed to implement certain procedures for no-load operation of the diesel generators. Specifically, if diesel troubleshooting continues for 3 to 4 hours, the diesel would be loaded to at least 25 percent of full load for one hour.

By letter of April 23, 1984 the applicant clarified its intentions regarding load testing of the diesels. The applicant has ascertained from its diesel manufacturer, Cooper-Bessemer, that troubleshooting involving repeated starts is no worse than continuous no-load operation. Therefore, the applicant intends to load the diesel to 25 percent for one hour after eight hours of no-load operation, regardless of the number of starts. The staff finds this procedure acceptable.

The original SER stated that the controls and monitoring instrumentation are installed on a free-standing floor mounted panel separate from the engine skids, and located in a vibration free floor area. The response to question 040.94 states that the design of the floor slab is such that the slab mass has been proportioned to the equipment mass to minimize vibration and impact loads. The staff does not consider this to be a vibration free floor area.

By letter dated October 16, 1984 the applicant has provided an evaluation to resolve this concern, which is being reviewed by the staff. Until the review is completed, a license condition has been added that requires the applicant, prior to startup after the first refueling outage, to dynamically qualify the controls and monitoring instrumentation for their present location, or install them on a free standing floor mounted panel in such a manner (including the use of vibration isolation mounts if necessary) that any induced vibrations will not result in a cyclic fatigue failure for the expected life of the instrument.

The staff has determined that exemptions are required from GDC-13 and GDC-17 to Appendix A. GDC-13 requires that instrumentation and controls shall be provided to monitor variables and systems over their anticipated ranges for normal operations, for anticipated operational occurrences, and for accident conditions. GDC-17 requires that provisions be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, loss of power from the transmission network, or loss of power from the onsite electric power supplies. The staff does not expect that there will be enough induced vibrations

prior to the first refueling outage to cause cycle fatigue failure of the instruments. Therefore, the staff concludes that the exemptions from GDC-13 and GDC-17 for the first cycle of operation will not endanger life or property or the common defense and security and is otherwise in the public interest.

11 RADIOACTIVE WASTE MANAGEMENT

11.3 Gaseous Waste Management Systems

11.3.1 Summary Description

Since the Byron SER was issued, the applicant has amended the Byron FSAR on several occasions. Some of these revisions have made it necessary for the staff to review previous conclusions presented in the Byron SER to ensure that those conclusions are still valid. Some of the changes that the applicant has made involve exceptions to the regulatory positions of Regulatory Guide 1.140, "Design, Testing and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants."

The applicant indicated in Amendment 42 to the FSAR that only the post-LOCA purge unit's filter housing would be leak tested to the requirements of ANSI N509-1976 as required in Regulatory Positions 2.f and 3.f of Regulatory Guide 1.140. The applicant has stated that all other non-ESF filter housings, except for the technical support center, are at negative pressure with respect to their surroundings and that the housings are located in low airborne radiation environments. Therefore, any inleakage will not adversely affect Appendix I releases. The applicant stated that the technical support center unit filter housing is located in an area where the airborne radiation level of the room air may exceed that of the air within the housing. However, the technical support center filter unit is at positive pressure with respect to the room. Therefore, the applicant did not propose testing its filter housing to ANSI N509-1976 either. The applicant did propose to perform leak tests of all system filter mounting frames in accordance with ANSI N510-1980.

The applicant also took exception to the ductwork leak rate testing requirements of ANSI N509-1976. The applicant stated that any ductwork sections where leakage could affect the habitability of the control room or the technical support center would be tested to this standard. The applicant provided a table which identified the Regulatory Guide 1.140 filter units and whether charcoal adsorption and/or HEPA filtration was provided. The table contained, for each filter unit, justification for excluding ductwork testing based on ANSI N509-1980 exceptions noted in Section 5.10.8 of that standard. Table 11.3-1 presents those portions of the non-ESF filter systems proposed for exclusion from the ductwork leak rate testing criteria.

The applicant did test the off-gas system discharge ductwork and sections of the miscellaneous ventilation system ductwork passing through the control room boundary and the results of the test were found to be within the limits of Section 4.12 of ANSI N509-1976. The applicant also indicated in Amendment 42 that airflow distribution and aerosol mixing tests will not be performed on the non-entry type filter units.

11.3.2 Evaluation Findings

The staff has reviewed the applicant's amended exceptions to the regulatory positions of Regulatory Guide 1.140. The staff finds it acceptable not to perform air flow distribution and aerosol mixing tests on the non-entry type filter unit. These filter units are typically a few hundred cfm systems and such testing is difficult without special modifications. Therefore, the exception to this regulatory position is acceptable.

The staff has accepted the exception taken by the applicant with respect to leak testing of certain system's housings.

The staff was concerned that sections of the ductwork which supply air to filter systems, which contain charcoal adsorber units, may be drawing through leakage air which contains paint fumes, various organics, industrial pollutants, smoke, etc., which could poison the charcoal. The applicant may be unaware that such pollutants are being drawn into the system since the leak-tightness of the ductwork is unknown. Thus, laboratory analysis of the charcoal may not be performed when needed or as required by Regulatory Guide 1.140. The applicant will install signs throughout the various buldings which could have their air treated by charcoal adsorbers to ensure that the charcoal is not poisoned by chemical fumes. The signs will be similar to those discussed in Section 6.5.1 of this SSER.

The applicant has presented how various stretches of ductwork qualify for the exceptions to testing, as presented in Section 5.10.8.1 of ANSI N509-1980. All negative pressure non-ESF ventilation systems with charcoal adsorbers in the filter units have hard piping in lieu of sheet metal duct construction. Two exceptions are the volume reduction (VR) and the technical support center (TSC) units.

The VR ductwork is less than approximately thirty feet and within the radwaste building. Leakage would be minimal due to the length of duct. The TSC ductwork is totally within the TSC equipment area and normally inoperative. However, a chemical release or fire would have to occur within the equipment room to have any potential effect at all on the charcoal. The applicant has committed to testing the negative portion of the TSC ductwork to Regulatory Guide 1.140 criteria. The applicant will leak-test all non-ESF system ductwork to meet the maximum allowable leak rate of Section 4.12 of ANSI N509-1980.

The staff has determined that the exceptions to Regulatory Guide 1.140 are acceptable with the applicant's incorporation of the above comments.

11.4 Solid Waste Management Systems

The original SER stated that (1) the staff had not reviewed the polymer binder solidification system for conformance with SRP Section 11.4 and Regulatory Guide 1.143 since the applicant has not provided all pertinent information on the system design for staff review, and (2) the applicant had not provided the process control programs (PCP) for Byron Station, Unit Nos. 1 and 2, for staff review.

Subsequently, the applicant was asked to provide (1) additional design information on the polymer binder solidification system and the Byron PCP for the cement solidification system, and (2) the Byron PCP for the polymer binder solidification system. In response, the applicant provided the requested information in their transmittal letters dated October 11 and 16, 1984.

The staff has reviewed the polymer binder solidification portion of the Byron solid waste management system and the Byron PCPs for the cement and polymer binder solidification systems. The cement solidification portion of the Byron solid waste management system was reviewed in the original SER and found acceptable.

The scope of review of the polymer binder solidification system and the PCPs included piping and instrument diagrams, descriptive information, the applicant's proposed design criteria and design bases, and the applicant's analysis of those criteria and bases. The capability of the proposed system to process the types and volumes of wastes expected during normal operation and anticipated operational occurrences, in accordance with General Design Criterion (GDC) 60, provisions for the handling of wastes relative to the requirements of 10 CFR Parts 20 and 71, and of applicable DOT regulations, and the applicant's quality group classification and seismic design relative to Regulatory Guide 1.143, have also been reviewed. The applicant's proposed methods of assuring complete solidification have been reviewed and the processing and design features meet Branch Technical Position ETSB 11-3 and 10 CFR Part 61.

The staff concludes that the design of the system meets the requirements of 10 CFR Part 20, Section 20.106; 10 CFR Part 50.34a; and GDC 60, 63 and 64, and that the Byron PCPs for cement and polymer binder solidification systems meet the requirements in 10 CFR Parts 61 and 71, and Branch Technical Position ETSB 11-3, Rev. 2. The basis for acceptance has been conformance of the applicant's designs, design criteria, and design bases for the solid radwaste system to the regulations and guides referenced above, as well as to staff technical positions and industry standards. Based on the foregoing evaluation, the staff concludes that the proposed solid radwaste system is acceptable and Confirmatory Issue 37 is closed.

11.5 Process and Effluent Radiological Monitoring and Sampling Systems

In the Byron SER, the staff indicated that the applicant had not provided the calibration techniques nor the energy dependence of response of the noble gas monitor as required by TMI Items II.F.1, Attachment 1. The applicant has provided this information in its October 17, 1984 letter, and it has been found acceptable. This item is closed.

The Inspection Report enclosed in the July 10, 1984 letter from C. J. Paperiello to Cordell Reed identified concerns by the NRC inspectors on the ability of installed equipment to adequately meet the requirements of NUREG-0737, Item II.F.1, Attachment 2, sampling and analysis of iodine and particulate effluents. In particular, recent research into the deposition of airborne radioiodine on metal surfaces indicates that the Byron design may not provide a representative sample.

By letter dated August 17, 1984, the applicant committed to resolve this matter prior to startup following the first refueling outage. The staff finds the schedule acceptable because the noble gas monitor may be utilized to project the magnitude of radioiodine releases in the event that an accident occurs during the first cycle. Therefore, the license is being conditioned to require that, prior to startup following the first refueling outage, the applicant demonstrates that the operating iodine/particulate sampling system will perform its intended function.

Table 11.3-1 Portions of non-ESF filter system ductwork excluded from leak rate testing

System	Portion of System
Off-gas	Entire System
Laboratory Exhaust	Negative Pressure
Radwaste Building	Negative Pressure
Volume Reduction	Negative Pressure
Normal Purge	Entire System
Post-LOCA Purge	Negative Pressure
Containment Recirculation	Entire System
Technical Support Center Supply	Positive Pressure
Tank Vent	Entire System

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure of Applicant

13.1.2 Operating Organization

13.1.2.1 Organization

OPERATIONS

The Commission is concerned about the possible lack of hot operating experience among the operators on shift at newly licensed nuclear power plants. This has led to an evaluation of (1) the operating experience on shift proposed by the applicant and (2) the interim use of shift advisors to supplement the operating shift crews.

Operating Experience on Shift. Dialogue with the industry was begun in late-1983 to find a way of ensuring that each operating shift at a newly licensed plant had at least one senior operator with previous hot operating experience. On February 24, 1984, an Industry Working Group, representing utilities with nuclear power plants under construction or ready for operation, presented a proposal to the Commission on the amount of previous operating experience considered to be the minimum desirable on each shift and how that experience could be obtained. On June 14, 1984, the Commission accepted the industry proposal with certain clarifications. Information regarding the Commission action was forwarded to the industry as Generic Letter 84-16, dated June 27, 1984. The objective is that, at the time of fuel load, each operating shift will have at least one senior operator with a minimum of six months of hot operating experience on a similar type plant, including at least six weeks above 20% power and start-up/shutdown experience. However, for plants in the late stages of licensing with insufficient time to meet the objective, the temporary use of experienced shift advisors is acceptable. The minimum qualifications for shift advisors are 4 years of power plant experience (including 2 years of nuclear power plant experience) and 1 year of hot operating experience as a senior reactor operator (or reactor operator, if found suitably qualified) on a large commercial nuclear plant of the same type. All shift advisors are to be trained on the systems, procedures and Technical Specifications of the plant for which they are to provide advice, and they are to be certified to the NRC as being qualified to act as shift advisors.

The applicant's plans and information regarding the operating experience of licensed operators and the qualifications of shift advisors were submitted by letters dated July 23, 1984, and September 24, 1984. The submittals indicate that Byron Unit 1 plans to begin operation with a standard 6-crew shift cycle. Some of the shift engineers (senior reactor operators at the "shift supervisor" level) meet the operating shift experience requirements proposed by the Industry Working Group on February 24, 1984, and accepted, with clarification, by the Commission on June 14, 1984. At the time of fuel load, a certified shift

advisor will be assigned to any shift crew that does not meet the operating experience requirements.

The applicant has selected eight individuals to act as Byron Unit 1 shift advisors. All these individuals have licensed operator experience at large pressurized water reactors at other utilities; six have senior reactor operator experience ranging from 12 to 44 months and reactor operating experience ranging from 16 to 42 months, and the remaining two have reactor operator experience of 29 months and 72 months. Seven of the eight have nuclear navy experience.

The staff has reviewed the qualifications of the eight shift advisors and the plant-specific training provided to them at Byron Unit 1, and has concluded that, subject to certain clarifications, they meet the guidelines for shift advisors as adopted by the Commission. These clarifications are discussed below in the section on the Shift Advisor Program.

In addition, since Byron Unit 1 does not now have a senior operator for each shift who meets the minimum requirements for hot operating experience, the license will be conditioned to require shift advisors until such time as the requisite experience has been obtained. This license condition makes the applicant's previous commitment (letter dated February 3, 1982) unnecessary.

Shift Advisor Program. The staff has reviewed the information submitted by the applicant on July 23, 1984 and on September 24, 1984, for conformance to Generic Letter 84-16. In performing the review, the staff also used additional information regarding qualifications and training of shift advisors that was developed during the review of shift advisor programs at several other utilities.

The review of the Byron Unit 1 Shift Advisor Program comprised four main areas: shift advisor qualifications, the training program for shift advisors (including written and oral examinations), the procedures used to define shift advisor duties and responsibilities, and various other guidance pertaining to the use of shift advisors.

1. Shift Advisor Qualifications

   Six of the eight shift advisors amply meet the experience requirements of the Industry Working Group proposal of February 24, 1984, as clarified by the Commission on June 14, 1984. They all have greater than 5 years of equivalent nuclear power plant experience, and they have operating on-shift experience ranging from approximately 2 years to over 7 years.

   The remaining two shift advisors meet the experience requirements except that they have not been licensed as senior reactor operators. One individual has had over 5 years of equivalent nuclear power plant experience, approximately 2 years of hot participation experience above 20% power, over 2 years as a licensed reactor operator, and over 2 years experience on shift at a large Westinghouse PWR. The second individual has had over 8 years of equivalent nuclear power plant experience, approximately 2 years of hot participation experience above 20% power, approximately 6 years experience as a licensed reactor operator, over 2 years experience on shift at a large Combustion Engineering PWR, and approximately 2 years on

shift as a Shift Foreman at the Byron Generating Station. In total, the staff concludes that their extensive nuclear experience qualifies them to participate in the shift advisor program at Byron Unit 1.

2. Shift Advisor Training Program

The Byron Unit 1 Shift Advisor Training Program is 40 days in length and consists of 25 days of classroom instruction (including written and oral examinations), 10 days of on-shift training, and 5 days of simulator training.

The classroom portion of the training is conducted in two segments. The first segment consists of 20 days of instruction, with a written quiz approximately every 5 days. The second segment is 5 days long and consists of a comprehensive written final exam and an oral exam. The following major subject areas are covered:

- Nuclear fuel
- Primary systems
- Primary support systems
- Secondary systems
- Secondary support systems
- Instrumentation and control systems
- Electrical systems
- Emergency systems
- Engineered safety features
- Fuel handling systems
- Radiation monitoring systems
- Radwaste systems
- Procedures (general, abnormal, emergency, and administrative)
- Technical Specifications

The on-shift portion of the training is under the direction of the Byron Station Operating Department. It consists of 10 days of on-shift assignments as appropriate to complete the applicant's Shift Advisor Certification Guide. By completing the guide, the shift advisors gain practical experience to supplement the classroom training.

The simulator portion of the training consists of 5 days of familiarization with Byron controls and plant responses. It covers, in part, reactor theory, systems knowledge, communication practices, logs, procedures, Technical Specifications, leadership, attitude toward co-workers, and ability to supervise under various plant conditions.

The staff concurs with the Byron Unit 1 Shift Advisor Training Program.

3. Shift Advisor Procedures

The specific duties and responsibilities of the shift advisors are described in procedures BAP 300-22 (Conduct of Operations) and BAP 200-A2-10 (Shift Advisor Position Description). The duties and responsibilities include:

- Keep aware of plant status.

- Provide advice and recommendations concerning plant operations to the Shift Engineer, who is the lead operation's supervisor on shift (procedural limitations preclude the shift advisor from ordering plant shutdown or manipulating controls on the Main Control Board and the Remote Shutdown Panel that affect reactor power or reactivity).

- If necessary, resolve disagreements with the shift engineer by involving more senior plant supervisors (up to the station superintendent).

- Participate in shift turnover and shift briefings.

- Review shift turnover forms, Main Control Board line-ups, and various logs.

- Review, assess, observe and/or assist in significant plant evolutions.

- Monitor procedures in use by the shift.

- Assist in resolving problems related to the Technical Specifications.

- Assist the shift staff in coordinating plant evolutions and resolving operating problems.

The staff concurs with the Byron Unit 1 shift advisor procedures. The staff agrees with the limitations that restrict the shift advisor from ordering plant shutdown or manipulating specific controls. The staff particularly agrees that the shift advisor be given the opportunity to make unrestricted recommendations and to pursue the resolution of disagreements.

4. Additional Shift Advisor Requirements

The operating shift crews will be trained on the role of the shift advisor by using the plant procedures that deal with the shift advisor position. Before initial criticality, the applicant should verify that all shift crews have been trained in the latest version of the procedures.

The applicant has stated that all shift advisors have been previously licensed and, therefore, have passed the NRC medical qualification for a reactor operator license. This is not acceptable unless the licenses were current at the time of contract or employment with Commonwealth Edison Company. The applicant should take steps to medically certify any shift advisor who does not satisfy this requirement. The medical examination should be comparable to that required by 10 CFR 55.60. The applicant does not have to submit the results of shift advisor medical examinations to the staff.

Every 4 months, the applicant plans to conduct and document a detailed review of shift advisor progress. The review includes, but is not limited to, communications, attitude, ability to mesh with the shift crew, and ability to provide useful technical information and recommendations to the Shift Engineer. The staff concurs with the content and scheduling of the

formal reviews planned by the applicant, but further recommends that plant and corporate management take steps to more frequently monitor the shift advisor program on an informal basis. The shift advisor, when necessary, is an important part of the shift crew, and shift interactions should be monitored closely to verify effectiveness.

The applicant has not indicated whether the shift advisors will participate in the licensed operator requalification program. The staff (and industry reviewers at other plants) recommends that the Byron Unit 1 shift advisors be enrolled in the operator requalification program and, when possible, attend training sessions with their assigned crews.

14 INITIAL TEST PROGRAM

By letter dated September 28, 1984, the applicant proposed to defer preoperational testing on the Auxiliary Building Ventilation and Containment Purge Systems to the period between fuel loading and 25% of full power. In addition, the applicant proposed to defer retesting on Process Radiation Monitoring, Control Room Ventilation, Main Steam Isolation Valves, Diesel Generator Ventilation, Process Radiation Monitoring - Loops 2, 5, Leakage Control, Fuel Pool Cooling, Pipe Vibration (test), Control Room Chilled Water and Containment Ventilation Systems until after fuel loading.

The staff has reviewed the applicant's proposed preoperational test deferrals and justification and finds them acceptable as proposed.

15 ACCIDENT ANALYSES

15.3 Design-Basis Accidents

15.3.6 Reactor Coolant Pump Rotor Seizure and Shaft Break

In the original SER, the staff requested that the postulated reactor coolant pump locked rotor accident be reevaluated assuming turbine trip and consequential loss of offsite power and assuming single failure of safety systems. The staff also required the applicant to provide an analysis of a postulated sheared reactor coolant pump shaft accident to verify that the consequences were no more severe than those for a locked rotor. The applicant provided additional information in letters dated June 7, 1982, September 22, 1982, May 2, 1984, and September 26, 1984.

The applicant evaluated the time required for offsite power to be lost following the reactor trip/turbine trip which would result from reactor coolant pump shaft failure. The applicant determined that offsite power could not be lost until after the departure from nucleate boiling ratio (DNBR) went through its minimum value during the event. Therefore, loss of offsite power would not affect the amount of fuel failure. The applicant also evaluated the effect of a single active component failure on the event consequences, including single failure of the ECCS, auxiliary feedwater, pressurizer PORV, and secondary system isolation valves. The thermal hydraulic transient was determined to be terminated before any single active component failures of these systems could affect the results. The applicant evaluated the consequences of a postulated sheared shaft accident and determined that the consequences were not significantly different from those for a locked rotor. The staff agrees with the applicant's above conclusions.

The staff requested additional analyses of the consequences of a stuck open secondary relief valve on the offsite dose consequences. Nine percent of the fuel was originally calculated to experience DNB in the FSAR analysis and was assumed to fail. This large amount of fuel failure could have a significant effect on the offsite dose consequences assuming a stuck open secondary relief valve and operator action to isolate feedwater from the affected steam generator in accordance with Westinghouse Emergency Response Guidelines. If the steam generator with the stuck open valve were allowed to dry out, a direct path would exist for fission products from failed fuel to pass through any steam generator tube leaks directly into the atmosphere.

The applicant's calculation which resulted in 9% of the fuel in DNB assumed an initial power peaking factor of 3.0 for which DNB was assumed to occur as an initial condition for the transient. As discussed in Chapter 4.3 of the FSAR, the power distribution at Byron will be limited so that the maximum peaking factor will be no greater than 2.32. Using the less limiting power peaking assumptions, the applicant determined that DNB will not occur for a locked rotor/sheared shaft accident. This result was confirmed by the Argonne National Laboratory under contract to the NRC staff. In the absence of DNB, fuel failure is not predicted to occur.

In the event that a secondary relief valve stuck open, the offsite dose consequences would be bounded by those of a postulated main steam line break outside containment. These results have already been found to be acceptable by the staff in SER section 15.4.2. The staff concludes that Confirmatory Issue 34 is closed.

15.4 Radiological Consequences of Accidents

15.4.3 Steam Generator Tube Failure

In the Byron/Braidwood FSAR, the applicant made general, unverified assumptions concerning system performance following a complete severance of a single steam generator tube. In addition, the FSAR assumed that the break flow was terminated within 30 minutes of the event by operator actions to equalize the primary and secondary pressures. In the original SER, the staff addressed the accident, including the sequence of events and the radiological consequences, and found them acceptable. However, the actual steam generator tube rupture (SGTR) that occurred at Ginna indicated that more than 30 minutes could be required for pressure equalization, implying that the Byron/Braidwood analysis may be nonconservative with respect to assumed operator actions.

As a result, the staff requested additional information including an evaluation of operator action times, as to whether liquid can enter the steam lines, and what the effects were on the integrity of steam piping and supports. The staff also requested that a reactor systems analysis be performed for natural circulation cooldown with a SGTR including the effect of the worst single failure of a system that is either required or expected to operate during the event. By letter dated October 12, 1984, the applicant committed to work with Westinghouse and the NRC staff to find resolution consistent with other Westinghouse owners. The current schedule for responding to the staff questions is December 31, 1984 for all but one question which is scheduled for May 1985. The applicant committed to this schedule in its letter dated October 29, 1984.

To justify safe operation until the SGTR issue is satisfactorily resolved, the staff notes the following: (1) all components necessary for mitigation of the design basis SGTR are safety related, (2) the emergency procedures for SGTR are based on generic guidelines which have been reviewed and approved by the NRC staff, and (3) there is a low probability of a design basis SGTR during initial operation. The staff concludes that there is sufficient assurance that the plant can operate safely until the issue is completely resolved.

APPENDIX A

Continuation of the chronology of the NRC staff's radiological safety review for the period April 1, 1984 to August 31, 1984.

April 2, 1984	Letter from applicant concerning technical specifications.
April 9, 1984	Letter from applicant concerning technical specifications.
April 11, 1984	Letter from applicant concerning supplemental information to the resolution of "Control of Heavy Loads at Nuclear Power Plants."
April 18, 1984	Letter from applicant concerning preservice inspection program plan.
April 18, 1984	Letter from applicant concerning River Screenhouse Seismic Design.
April 19, 1984	Letter to applicant requesting additional information on the steam generator tube rupture.
April 20, 1984	Letter to applicant concerning instrumentation for detection of inadequate core cooling.
April 23, 1984	Letter to applicant concerning diesel generator load testing.
April 25, 1984	Letter to applicant requesting additional information on Process Control Program and Polymer Waste Solidification System.
April 26, 1984	Representatives from NRC and Commonwealth Edision Company meet in Bethesda, Maryland to discuss analyses used to justify increased outage in Byron Technical Specifications (Summary issued May 2, 1984).
April 27, 1984	Representatives from NRC and Commonwealth Edison Company meet in Bethesda, Maryland to discuss alternate means of determining subcooling margin at Byron/Braidwood (Summary issued May 2, 1984).
May 2, 1984	Letter from applicant concerning technical specification changes.
May 2, 1984	Letter from applicant concerning reactor coolant pump transients.
May 3, 1984	Letter from applicant concerning penetrameter placement during radiography.

May 4, 1984	Letter from applicant concerning core damage assessment procedure.
May 14, 1984	Representatives from NRC, HQS and Region III staff meet in Bethesda, Maryland to discuss the Byron/Braidwood Safety-related D.C. System.
May 17, 1984	Letter to applicant concerning Byron 1 pre-service inspection program.
May 23, 1984	Letter to applicant transmitting 20 copies of NUREG-0876 Supplement 4 to the Byron Safety Evaluation Report.
June 8, 1984	Letter to applicant concerning ASME Code Case N-401.
June 11, 1984	Letter to applicant concerning Safety-Related D.C. System request for additional information.
June 12, 1984	Letter from applicant transmitting FSAR Amendment 45.
June 18, 1984	Letter from applicant concerning piping design criteria.
June 30, 1984	Letter from applicant concerning Supplemental Response to Generic Letter No. 83-28 "Required Actions Based on Generic Implications of Salem ATWS Events".
July 2, 1984	Letter from applicant concerning Offsite Dose Calculation Manual.
July 5, 1984	Letter from applicant concerning Byron Security Plan Revision 11.
July 6, 1984	Letter from applicant concerning subcooling margin monitor.
July 6, 1984	Letter from applicant transmitting responses on safety-related D.C. System
July 16, 1984	Letter from applicant concerning masonry walls.
July 16, 1984	Letter from applicant concerning technical specifications.
July 19, 1984	Letter from applicant concerning technical specifications.
July 19, 1984	Letter to applicant requesting additional information - Byron Technical Specifications.
July 19, 1984	Letter to applicant requesting additional information - Volume Reduction System.
July 25, 1984	Letter to applicant concerning information needed to support Byron 1 Fuel Load.
July 26, 1984	Letter from applicant concerning the Byron Technical Specifications.

August 13, 1984	Letter to applicant concerning Byron Station, Units 1 and 2 Physical Security Plan.
August 13, 1984	Representatives from NRC and commonwealth Edison Company meet in Bethesda, Maryland to discuss the resolution of differing opinions on Draft Technical Specifications for Byron 1 (Summary issued October 2, 1984).
August 13, 1984	Letter from applicant concerning post-accident sampling system.
August 13, 1984	Letter from applicant requesting extension of the latest construction completion date for Unit 1. Extension requested from October 1, 1984 to January 1, 1985.
August 13, 1984	Letter from applicant concerning inservice inspection program.
August 13, 1984	Letter from applicant concerning improved thermal design procedure.
August 14, 1984	Representatives from NRC & Commonwealth Edison Company met in Bethesda, MD to discuss Commonwealth Edison Company's response to Byron integrated design inspection report (Summary issued August 20, 1984).
August 15, 1984	Letter from applicant concerning technical specifications.
August 16, 1984	Letter from applicant concerning evacuation time estimates.
August 16, 1984	Letter from applicant transmitting an affidavit for distribution of FSAR Amendments 44 and 45.
August 17, 1984	Letter from applicant concerning plant effluent sampling.
August 21, 1984	Letter from applicant concerning diesel generator 2A availability.
August 22, 1984	Letter to applicant requesting additional information on Byron Technical Specifications Reactor Systems Area.
August 22, 1984	Letter to applicant requesting additional information - Environmental Qualification of Byron Equipment.
August 23, 1984	Letter from applicant concerning technical specifications.
August 24, 1984	Letter from applicant concerning volume reduction system.
August 27, 1984	Letter to applicant transmitting a copy of the Byron Station, Unit 1 technical specifications in final draft form.
August 29, 1984	Letter from applicant concerning security plans.

September 7, 1984	Letter from applicant concerning pipe whip restraints utilizing crushable energy absorbing material.
September 11, 1984	Letter from applicant concerning revised response "Control of Heavy Loads at Nuclear Power Plants."
September 12, 1984	Letter to applicant concerning pump and valve inservice testing program.
September 17, 1984	Letter from applicant concerning elimination of postulated pipe breaks in the RCS primary loop.
September 18, 1984	Letter from applicant concerning environmental qualification of equipment.
September 18 and 19, 1984	Representatives from NRC & Commonwealth Edison met in Bethesda, MD to discuss changes to final draft technical specifications for Byron 1.
September 19, 1984	Letter to applicant concerning Byron Station Unit 1 Technical Specifications.
September 19, 1984	Letter from applicant concerning Technical Specifications.
September 20, 1984	Letter from applicant concerning Technical Specifications.
September 25, 1984	Letter from applicant concerning pipe whip restraints utilizing crushable energy absorbing material.
September 25, 1984	Letter from applicant concerning instrumentation for the detection of inadequate core cooling.
September 25, 1984	Letter from applicant concerning Technical Specifications.
September 26, 1984	Letter from applicant concerning turbine missiles.
September 26, 1984	Letter from applicant concerning pump and valve operability.
September 28, 1984	Letter from applicant concerning completion of pre-operational test program.
October 1, 1984	Letter from applicant concerning groundwater monitoring.
October 4, 1984	Letter from applicant concerning Technical Specifications.

APPENDIX B

BIBLIOGRAPHY

S. H. Bush, "Probability of Damage to Nuclear Components Due to Turbine Failure," Nuclear Safety, 14, 3, (May-June) 1973, p. 187.

L.A. Twisdale, W.L. Dunn, and R.A. Frank, "Turbine Missile Risk Methodology and Computer Code," EPRI Seminar on Turbine Missile Effects in Nuclear Power Plants, Palo Alto, California, October 25-26, 1982.

NUREG/CR-1884, "Observations and Comments on the Turbine Failure at Yankee Atomic Electric Company, Rowe, Massachusetts," March 1981.

Preliminary Notification of Event or Unusual Occurrence -- PNO - III - 81 - 104 -- "Circle in the hub of the eleventh stage wheel in the main turbine" at Monticello Nuclear Power Station, Nov. 24, 1981.

Licensee Event Report No. 82-132, Docket No. 50-361 -- "Failure of turbine stop valve 2UV-2200E to close fully" at San Onofre Nuclear Generating Station, Unit 2, Nov. 19, 1982.

J.J. Burns, Jr., "Reliability of Nuclear Power Plant Steam Turbine Overspeed Control Systems," 1977 ASME "Failure Prevention and Reliability Conference," Chicago, Illinois (Sept.) 1977, p. 27.

D. Kalderon, "Steam Turbine Failure at Hinkley Point A," Proc. Instn. Mech. Engrs., 186, 31/72, 1972, p. 341.

W.G. Clark, Jr., B.B. Seth, and D.H. Shaffer, "Procedures for Estimating the Probability of Steam Turbine Disc Rupture from Stress Corrosion Cracking," ASME/IEEE Power Generation Conference Oct. 4-8, 1981, St. Louis, Missouri.

NUREG-0717, Supplement No. 4, "Safety Evaluation Report Related to the Operation of Virgil C. Summer Nuclear Station Unit No. 1," Docket No. 50-395, August 1982.

WCAP-9804, "Probabilistic Analysis and Operation Data in Response to NUREG-0737 Item II.K.3.2 for Westinghouse NSSS Plants," Westinghouse Electric Corporation, February 1981.

EPRI NP-2628-SR Special Report, "EPRI PWR Safety and Relief Valve Test Program - Safety and Relief Valve Test," December 1982.

NUREG-1014, "Safety Evaluation Report Related to the D4/D5/E Steam Generator Design Modification," October 1983.

APPENDIX F

NRC Staff Contributors and Consultants

This Supplement No. 5 to the SER is a product of the NRC staff and its consultants. The NRC staff members listed below were principal contributors to this report.

NAME	TITLE	REVIEW BRANCH
R. Rothman	Geophysicist	Geosciences
J. Chen	Geotechnical Engineer	Structural and Geotechnical Engineering
J. Schiffgens	Materials Engineer	Materials Engineering
R. Lipinski	Sr. Structural Engineer	Structural and Gentechnical Engineering
N. Chokshi	Structural Engineer	Structural and Geotechnical Engineering
G. Hammer	Mechanical Engineer	Mechanical Engineering
Y. Hsii	Nuclear Engineer	Core Performance
T. Huang	Nuclear Engineer	Core Performance
M. Hum	Materials Engineer	Materials Engineering
E. Chow	Reliability and Risk Analyst	Reliability and Risk Assessment
R. Anand	Mechanical Engineer	Auxiliary Systems
P. Wu	Chemical Engineer	Chemical Engineering
R. Giardina	Mechanical Engineer	Power Systems
W. Jensen	Sr. Nuclear Engineer	Reactor Systems
J. Pulsipher	Containment Systems Engineer	Containment Systems
N. Fioravante	Mechanical Engineer	Auxiliary Systems
D. Kubicki	Fire Protection Engineer	Chemical Engineering
J. Rajan	Mechanical Engineer	Mechanical Engineering
J. Wermiel	Section Leader	Auxiliary Systems
G. Staley	Hydraulic Engineer	Environmental and Hydrologic Engineering
H. Garg	Sr. Electrical Engineer	Equipment Qualification
A. Lee	Sr. Mechanical Engineer	Equipment Qualification
J. Jackson	Mechanical Engineer	Equipment Qualification
J. Hayes	Nuclear Engineer	Meteorology and Effluent Treatment
J. Lee	Nuclear Engineer	Meteorology and Effluent Treatment

APPENDIX G

ERRATA TO BYRON SAFETY EVALUATION RELPORT

Page	Line	Change
1-12	28	For Confirmatory Issue (18), change "Section 6.2.2.1" to "Section 6.2.1.1."

APPENDIX I

PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

I. INTRODUCTION

This section was prepared with technical assistance of DOE contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities whose construction permit was issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) specifies that components shall meet the preservice examination requirements set forth in Editions of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda applied to the construction of the particular component. The provisions of 10 CFR 50.55a(g)(3) also state that components (including supports) may meet the requirements set forth in subsequent Editions and Addenda of this Code which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In letters dated March 1, 1983, August 26, 1983, December 6, 1983, December 14, 1983, February 17, 1984, and April 18, 1984, the Applicant submitted revised weld examination tables for the Byron Unit 1 Preservice Inspection Program along with notes clarifying the extent of examinations performed on particular items and requests for relief from ASME Section XI Code requirements which the Applicant has determined to be not practical. The relief requests were supported by information pursuant to 10 CFR 50.55a(a)(2)(i). Therefore, the staff evaluation consisted of reviewing the Applicant's submittal to the requirements of the above referenced Code and determining if relief from the Code requirements were justified.

II. TECHNICAL REVIEW CONSIDERATIONS

A. The construction permit was issued on December 31, 1975. In accordance with 10 CFR 50.55a(g)(3), components (including supports), which are classified as ASME Code Class 1 and 2, have been designed and provided with access to enable the performance of required preservice examinations set forth in the 1977 Edition of ASME Section XI, including the Addenda through Summer 1978.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements which by themselves provide the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specification. As a part of these examinations, all of the primary pressure boundary full penetration welds were volumetrically examined (radiographed) and the system will be subjected to hydrostatic pressure tests.

C. The intent of a preservice examination is to establish a reference or baseline prior to the initial operation of the facility. The results of subsequent inservice examination can then be compared with the original condition to determine if changes have occurred. If review of the inservice inspection results shows no change from the original condition, no action is required. In the case where baseline data are not available, all flaws must be treated as new flaws and evaluated accordingly. Section XI of the ASME Code contains acceptance standards which may be used as the basis for evaluating the acceptability of such flaws.

D. Other benefits of the preservice examination include providing redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during the component fabrication. Successful performance of preservice examination also demonstrates that the welds are inspectable during the subsequent inservice examination using a similar test method.

In the case of Byron Station Unit 1, a large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

E. In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring supplemental examinations to be performed at this time (before plant startup) would result in hardships or unusual difficulties without a compensating increase in the level of quality or safety. The performance of supplemental examinations, such as surface examinations, in areas where volumetric inspection is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code, Section III fabrication examinations.

In cases where parts of the required examination areas cannot be effectively examined because of a combination of component design or current examination technique limitations, the development of new or improved examination techniques will continue to be evaluated. As improvements in these areas are achieved, the staff will require that these new techniques be made a part of the inservice examination requirements for the components or welds which received a limited preservice examination.

Several of the preservice inspection relief requests involve limitations to the examination of the required volume of a specific weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic degradation. In the event that the welds identified in the PSI relief requests are required to be examined again, the possibility of augmented inservice inspection will be evaluated during review of the Applicant's initial 10-year ISI program. An augmented program may include increasing the extent and/or frequency of inspection of accessible welds.

III. EVALUATION OF RELIEF REQUESTS

The Applicant requested relief from specific preservice inspection requirements in submittals dated March 1, 1983, August 26, 1983, December 6, 1983, and December 14, 1983. In letters dated February 17, 1984 and April 18, 1984, the Applicant submitted additional information regarding the ultrasonic examination of cast stainless steel component welds listed in Relief Requests NR-4, NR-6, and NR-8 and also requested that Notes 5 and 11 be evaluated as relief requests. Based on the information submitted by the Applicant and review of the design, geometry, and materials of construction of the components, certain preservice requirements of the ASME Boiler and Pressure Vessel Code, Section XI have been determined to be impractical and imposing these requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(2), conclusions that these preservice requirements are impractical are justified as follows. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1977 Edition, including Addenda through Summer 1978.

A. Relief Request NR-1, Examination Category B-J, Chemical and Volume Control System Weld J-15 on Line ICVB7A-3"

Code Requirements: The subject Code Class 1 weld is required to receive a preservice surface examination in accordance with Table IWB-2500-1 (Category B-J), Item B9.21.

Code Relief Request: Relief is requested from performing the required surface examination on the inaccessible weld.

Reason for Request: Circumferential weld J-15 on line ICVB7A-3" is inaccessible for a surface examination because it is located 54" inside the missile barrier wall which prevents any meaningful surface examination. The pipe is fabricated from type 304 austenitic stainless steel which possesses a high toughness and therefore is not expected to experience a rapidly propagating failure.

In addition, the Applicant has proposed a visual examination (leak test) in lieu of the required surface examination. Visual aids suitable to VT-2 requirements will be utilized for the inspection of the subject weld.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject weld received volumetric examination by radiography and surface examination in accordance with the ASME Code Section III, Class 1, requirements during fabrication.

2. Other similar welds in the same piping run received full Code examinations. The integrity of the pressure boundary thus was verified by sampling.

3. The subject piping weld received a system hydrostatic test in accordance with ASME Code Section III requirements, and will also receive a system hydrostatic test each inspection interval in accordance with ASME Code Section XI, Class 1 requirements.

4. Based on the above, the staff has determined that the visual examination (leak test) proposed by the Applicant is an acceptable alternative to the code required surface examination.

B. Relief Request NR-2, Examination Category C-F, 24 Class 2 Welds in the Main Steam, Safety Injection and Residual Heat Removal Systems

Line Number	Weld Number
1MS07BA-28"	C-3, C-4, C-5, C-9, and C-10
1MS07BB-28"	C-3, C-4, C-5, C-6, and C-10
1MS07BC-28"	C-3, C-4, C-5, C-6, and C-7
1MS07BD-28"	C-3, C-4, C-5, C-9, and C-10
1SI06BA-24"	C-18
1SI06BB-24"	C-24
1RH01CA-16"	C-1L
1RH01CB-16"	C-1L

Code Requirements: The subject Class 2 branch connection welds are required to receive preservice surface examinations in accordance with Table IWC-2500-1 (Category C-F) Items C5.31 and C5.32.

Code Relief Request: Relief is requested from performing the required surface examinations on the inaccessible welds.

Reason for Request: The above listed welds are inaccessible for surface examinations, due to the location of saddle plates covering the pressure retaining branch connection welds. The majority of the saddle plates have "weep holes" to detect degradation of the pressure retaining weld. The Applicant has committed to a surface examination (liquid penetrant) and visual examination (leak test) on the saddle plate fillet welds in lieu of the required surface examinations for the pressure retaining welds listed above.

Staff Evaluation: This relief request is acceptable based on the following considerations:

1. The branch pipe circumferential welds listed above have received radiographic volumetric examinations in accordance with the ASME Code Section III, Class 2, requirements during fabrication.

2. The as-built component geometry makes the required Section XI examination impractical. Removal of the welded reinforcement collars to make the area accessible for a preservice surface examination would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety since the radiography performed during

construction on the branch pipe circumferential welds verify the preservice structural integrity. Based on the above, the staff has determined that performing a surface and visual examination of the saddle plate fillet weld is an acceptable alternative to the code required surface examination.

C. Relief Request NR-3, Examination Category B-J, 8 Cast Stainless Steel Elbow-to-Cast Stainless Steel Pump or Valve Welds (Fitting to-Fitting)

Elbow-to-Pump Welds		Elbow-to-Valve Welds	
Line Number	Weld Number	Line Number	Weld Number
1RC02AA-31"	J-8	1RC01AA-29"	J-4
1RC02AB-31"	J-8	1RC01AB-29"	J-4
1RC02AC-31"	J-8	1RC01AC-29"	J-4
1RC02AD-31"	J-8	1RC01AD-29"	J-5

Code Requirement: The subject Class 1 welds are required to receive a preservice surface and volumetric examination in accordance with Table IWB-2500-1, Category B-J, Item B9.11.

Code Relief Request: Relief is requested from performing a preservice ultrasonic examination on these cast austenitic stainless steel component-to-fitting welds.

Reason for Request: The Applicant has determined that the welds joining the SA-351-CF8A elbows to either the SA-351-CF8 pump casings or SA-351-CF8M valve bodies have very poor acoustic properties which do not lend themselves to a meaningful ultrasonic examination. Attempts were made to ultrasonically examine these welds without success. The Applicant sent a representive section of the elbow material with artificial reflectors to a major manufacturer of transducers to determine whether an effective search unit could be developed. The Applicant reported that after six months effort, the manufacturer failed to find any combination of search unit parameters that would penetrate the material more than 1/2 to 3/4 inch in metal path with a useful signal-to-noise ratio.

The Applicant states that cast austenitic stainless steels are extremely tough and resistant to intergranular stress corrosion cracking and leakage long before complete failure is virtually certain. Leakage within the Reactor Coolant System will be checked each refueling outage. In addition, leakage within the containment will be continuously monitored by two remote methods: (1) leakage flow into the weir box of the containment sump (capable of detecting a 2-gpm leak within 1 hour) and (2) a containment radiation monitoring system (capable of detecting a 1-gpm leak within 1 hour). Additional atmospheric monitoring is provided by pressure, temperature, and humidity monitors. All atmospheric monitors are monitored in the main control room.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject welds received both volumetric examination by radiography and surface examinations during fabrication in accordance with ASME Code Section III requirements.

2. The staff has determined that the Applicant has made a reasonable effort to develop, within the state-of-the-art, effective ultrasonic testing equipment required to examine the cast stainless steel welds.

3. The staff has determined that the radiography and surface examination performed during construction provides reasonable assurance of the preservice structural integrity of the subject welds.

4. In addition, the staff will require that the Applicant include in the first inservice inspection (ISI) program a longitudinal wave ultrasonic examination of the elbow welds subject to ISI. In the event that this examination establishes adequate acoustic penetration of the cast material, the staff will require that angle beam ultrasonic examinations be performed on the elbow side using the best available procedures and instrumentation.

5. The staff will continue to evaluate the development of new or improved procedures and will require that these improved procedures be made a part of the inservice examination requirements.

D. Relief Request NR-4, Examination Category B-F, 8 Cast Stainless Steel Elbow-to-Cast Carbon Steel Nozzle Welds (Steam Generator Safe End Welds)

Line Number	Weld Number
1RC01AA-29"	F-2
1RC02AA-31"	F-1
1RC01AB-29"	F-2
1RC02AB-31"	F-1
1RC01AC-29"	F-2
1RC02AC-31"	F-1
1RC01AD-29"	F-2
1RC02AD-31"	F-1

Code Requirement: The Steam Generator nozzle-to-safe end welds are required to receive a preservice surface and volumetric examination in accordance with Table IWB-2500-1, Category B-F, Item B5.30.

Code Relief Request: Relief is requested from performing the required ultrasonic examination in the axial direction from the elbow side of the weld.

Reason for Request: The steam generator nozzles are cast carbon steel and the elbows are cast stainless steel. Ultrasonic examinations were performed circumferentially in both directions for transverse reflectors, and axially from the steam generator nozzle side for parallel reflectors with a one-half V-path scan. The Applicant examined these welds using a 45° refracted longitudinal wave transducer calibrated on the safe end-to-cast stainless steel mockup. This procedure was developed and qualified on a mockup consisting of safe end material welded to cast stainless steel fitting.

The Applicant has determined that a one-half V-path examination from the SA-351-CF8A elbow side of the weld could not be performed due to the poor acoustic properties of the cast austenitic stainless steel. The Applicant attempted to develop an ultrasonic transducer to perform the angle beam examinations required by the Code. The cast stainless steel material used for the mockup was obtained from the manufacturer of the cast stainless steel elbows at Byron Units 1 and 2 (and also at Braidwood Units 1 and 2). The mockup contained two holes in the cast stainless material. One hole was at the weld fusion line 1/4 T from the outer diameter (O.D.) of the cast stainless material. The other hole was in the corner of the required inspection volume 1/3 T from the inner diameter and approximately 1/2 inch from the fusion line into the cast material.

Straight beam examinations were performed during the preservice inspection to measure the wall thickness of the elbows. In addition, when a test of the attenuation characteristics of the mockup material and the cast elbows was performed using a 1 MHz straight beam transducer on the cast side of the mockup, 24 to 26 decibels (dB) gain was needed to obtain an 80 percent back wall reflection. With a 2.25 MHz transducer, 32 to 34 dB gain was needed to see the back reflection on the mockup. Performing the same test on a Byron Unit 2 pipe-to-elbow weld, 28 to 32 dB gain was needed for the 1 MHz transducer and 40 dB gain was required for the 2.25 MHz transducer. Thus, it was concluded that the cast elbows installed in the plant are more attenuative than the cast material in the mockup. The elbows installed in Byron Unit 1 can be expected to have the same attenuation properties since the same manufacturer provided elbows for all four units. This conclusion is substantiated by the fact that straight beam examinations performed on the Byron Unit 1 welds for thickness measurements required 30 to 40 dB gain to obtain a back reflection.

The 45° refracted longitudinal wave transducer was chosen to be used on the steam generator primary nozzle-to-elbow welds in an attempt to perform a meaningful examination on the cast material. However, during calibration the hole at the fusion line 1/4 T from the O.D. could not be seen from the cast side. As a result of this and because the elbows have even higher attenuation properties than the mockup, the Applicant concluded that an axial scan from the cast side of the welds using refracted longitudinal waves would also be meaningless. Therefore, these scans were not performed from the elbow side.

Refracted longitudinal waves were used to examine these welds axially from the nozzle side. During calibration on the mockup both holes in the cast stainless material were seen with 1/2 V-path examining across the weld. Therefore, it is estimated that during the scans from the nozzle side the heat-affected-zone (HAZ) on the cast stainless side was examined up to 1/2 inch beyond the fusion line.

Circumferential ultrasonic scans were also done in both directions and prior to the preservice inspections, ASME Code Section III radiographs were made during fabrication. Leakage within the Reactor Coolant System will be checked each refueling outage. In addition, leakage within the containment will be continuously monitored by two remote methods: (1) leakage flow into the weir box of the containment sump (capable of detecting a 2-gpm leak within 1 hour) and (2) a containment radiation monitoring system (capable of detecting a 1-gpm leak within 1 hour). Additional atmospheric monitoring is provided by pressure, temperature, and humidity monitors. All atmospheric monitors are monitored in the main control room.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject welds received both volumetric (radiography) and surface examinations during fabrication in accordance with ASME Code Section III requirements.

2. The staff has determined that the Applicant made a reasonable effort to develop, within the state-of-the-art, an effective ultrasonic testing equipment required to examine the cast stainless steel welds.

3. The staff has determined that the radiography and surface examinations performed during construction provides reasonable assurance of the preservice structural integrity of the subject welds.

4. The staff will require that the Applicant include in the first inservice inspection program the angle beam examinations from the steam generator safe end using a refracted longitudinal wave transducer to examine the weld metal and heat affected zone on the cast side to the maximum extent practical. In the event that this examination established adequate acoustical penetration of the cast material, the staff will require that angle beam ultrasonic examinations be performed on the elbow side using the best available procedures and instrumentation.

5. The staff will continue to evaluate the development of new or improved procedures and will require that these improved procedures be made a part of the inservice examination requirements.

E. Relief Request NR-5, Examination Category C-F, 5 Component-to Component Welds in the Safety Injection System

Line Number	Weld Number	Configuration
1SI04B-12"	C-14	Tee-to-Reducer
1SI05CA-8"	C-48	Reducer-to-Valve
1SI05CC-8"	C-3	Reducer-to-Elbow
1SI05CC-8"	C-4	Reducer-to-Valve
1SI05CD-8"	C-5	Reducer-to-Valve

Code Requirement: These welds are required to receive a preservice surface and volumetric examination in accordance with Table IWC-2500-1, Examination Category C-F, Item C5.21.

Code Relief Request: Relief is requested from performing the required ultrasonic examination in the axial direction to detect reflectors parallel to the weld.

Reason for Request: The axial scan could not be performed from either side of the weld due to the geometric configuration of the components. An ultrasonic examination in the circumferential direction for reflectors transverse to the weld was performed. A 0 degree calibrated L-wave examination was also performed as an alternative to the axial scan. These examinations showed no reportable indications. Also, the Section III hydrostatic test was performed without any reportable indications.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject welds received both radiographic and liquid penetrant examinations during fabrication in accordance with ASME Code Section III requirements.

2. The staff has determined that the radiography, liquid penetrant examination, and the hydrostatic test performed during construction and the 0 degree ultrasonic examination performed during PSI provide reasonable assurance of the preservice structural integrity.

F. Relief Request NR-6 and NR-8, Examination Category B-J, 40 Cast Stainless Steel Component-to-Wrought Stainless Steel Pipe or Safe End Welds

Cast Stainless Steel SA-351-CF8A

(Elbow)-to-Stainless Steel SA-376 Type 304N

(Pipe), Relief Request NR-6

Line Number	Weld Numbers
1RC02AA-31"	J-1, J-2, J-3, J-7
1RC02AB-31"	J-1, J-2, J-3, J-7
1RC02AC-31"	J-1, J-2, J-3, J-7
1RC02AD-31"	J-1, J-2, J-3, J-7
1RC03AA-27.5"	J-10
1RC03AB-27.5"	J-9
1RC03AC-27.5"	J-11
1RC03AD-27.5"	J-9

Cast Stainless Steel SA-351-CF8 (Pump)-to-Stainless Steel SA-376 Type 304N (Pipe), Relief Request NR-6

Line Number	Weld Numbers
1RC03AA-27.5"	J-1
1RC03AB-27.5"	J-1
1RC03AC-27.5"	J-1
1RC03AD-27.5"	J-1

Cast Stainless Steel SA-351-CF8M (Valve)-to-Stainless Steel SA-376 Type 304N (Pipe), Relief Request NR-6

Line Number	Weld Number
1RC01AA-29"	J-3
1RC01AB-29"	J-3
1RC01AC-29"	J-3
1RC01AD-29"	J-4
1RC03AA-27.5"	J-4, J-5

Line Number	Weld Number
1RC03AB-27.5"	J-4, J-5
1RC03AC-27.5"	J-4, J-5
1RC03AD-27.5"	J-3, J-4

Cast Stainless Steel SA-351-CF8A
(Elbow)-to-Stainless Steel SA-182 GR-F316
(Safe-end), Relief Request NR-8

Line Number	Weld Number
1RC03AA-27.5"	J-11
1RC03AB-27.5"	J-10
1RC03AC-27.5"	J-12
1RC03AD-27.5"	J-10

Code Requirement: These welds are required to receive a preservice volumetric and surface examination in accordance with Table IWB-2500-1, Examination Category B-J, Items B9.11 and B9.12.

Code Relief Request: Relief is requested from performing the required ultrasonic examination in the axial direction to detect reflectors parallel to the weld from the cast stainless steel component or elbow side of the weld.

Reason for Request: The Applicant has determined that a one-half V-path examination from the component side of the weld cannot be performed due to the poor acoustic properties of the cast stainless steel. The Applicant attempted to develop an ultrasonic transducer to perform the examinations required by the Code, but the effort was not successful.

Relief Request NR-6: Ultrasonic examinations were performed on these welds with a 45°-shear wave transducer calibrated on a block made of the pipe material per ASME Section XI. Axial scans were made from the pipe side to examine the required inspection volume of the piping material and weld metal for reflectors parallel to the weld.

Straight beam examinations were made on all welds to obtain thickness measurements and to detect any defects parallel to the surface. Since an additional 30 to 40 dB gain was needed to detect the back reflection on the cast stainless steel side, the Applicant concluded that shear wave examinations on this side would be meaningless. Therefore, axial scans from the cast side were not performed.

Additional examinations of these welds included circumferential ultrasonic scans on the weld crown in both directions for transverse reflectors and the ASME Code Section III radiography during fabrication.

Relief Request NR-8: The reactor nozzle safe end-to-cast stainless steel elbow welds originally were to be examined from the inner diameter by the automated reactor vessel examination tool. However, discovering that this could not be done and being aware that 45° shear wave examinations are meaningless on cast stainless steel, an examination procedure utilizing a 2.25 megahertz (MHz) 45-refracted longitudinal wave transducer was developed. This procedure was developed and qualified on a mockup consisting of safe end material welded to cast stainless steel. The cast stainless steel material was obtained from the manufacturer of the cast stainless steel elbows at Byron Units 1 and 2 (and also at Braidwood Units 1 and 2). The mockup contained two holes in the cast stainless material. One hole was at the weld fusion line 1/4 T from the outer diameter (O.D) of the cast stainless material. The other hole was in the corner of the required inspection volume, 1/3 T from the inner diameter and approximately 1/2 inch from the fusion line into the cast material.

A test of the attenuation characteristics of the mockup material and the cast elbows was performed. Using a 1 MHz straight beam transducer on the cast side of the mockup, 24 to 26 decibels (dB) gain was needed to obtain an 80 percent back wall reflection.

With a 2.25 MHz transducer, 32 to 34 dB gain was needed to see the back reflection on the mockup. Performing the same test on a Byron Unit 2 pipe-to-elbow weld, 28 to 32 dB gain was needed for 1 MHz transducer and 40 dB gain was required for 2.25 MHz transducer. Thus, it was concluded that the cast elbows installed in the plant are more attenuative than the cast material in the mockup. The elbows installed in Byron Unit 1 can be expected to have the same attenuation properties since the same manufacturer provided elbows for all four units. This conclusion is substantiated by the fact that straight beam examinations performed on the Byron Unit 1 welds for thickness measurements required 30 to 40 dB gain to obtain a back reflection.

The 45°-refracted longitudinal wave transducer was chosen to be used on the reactor safe end-to-elbow welds in an attempt to perform a meaningful examination on the cast material. However, during calibration the hole at the fusion line 1/4 T from the O.D. could not be seen from the cast side. As a result of this, and because the elbows have even higher attenuation properties than the mockup, the Applicant concluded that an axial scan from the cast side of the welds using refracted longitudinal waves would also be meaningless. Therefore, these scans were not performed from the elbow side.

Refracted longitudinal waves were used to examine these welds axially from the safe-end side. During calibration on the mockup both holes in the cast stainless material were seen with 1/2 V-path examining across the weld. Therefore, it is estimated that during the scans from the safe-end side the heat-affected-zone (HAZ) on the cast stainless side was examined up to 1/2 inch beyond the fusion line.

circumferential ultrasonic scans were also done in both directions and prior to the preservice inspections, ASME Code Section III radiographs were made. Leakage within the Reactor Coolant System will be checked each refueling outage. In addition, leakage within the containment will be continuously monitored by two remote methods: (1) leakage flow into the weir box of the containment sump (capable of detecting a 2-gpm leak within 1 hour and (2) a containment radiation monitoring system (capable of detecting 1-gpm leak within 1 hour. Additional atmospheric monitoring is provided by pressure, temperature, and humidity monitors. All atmospheric monitors are monitored in the main control room.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject welds received both volumetric (radiographic) and surface examinations during fabrication in accordance with ASME Code Section III requirements.

2. The staff has determined that the Applicant made a reasonable effort to develop, within the state-of-the-art, an effective ultrasonic testing equipment required to examine the cast stainless steel welds.

3. The staff has determined that the radiography performed during construction provides reasonable assurance of the preservice structural integrity of the subject welds.

4. During the preservice inspection, the welds identified in Relief Request #6 were examined with a 45° shear wave transducer from the pipe side. Shear waves may not be the most effective method of wave propagation to examine cast stainless steel as indicated in Relief Request #8. The staff will require that the Applicant include in the first inservice inspection program the angle beam examinations from the pipe side and reactor nozzle safe end with refracted longitudinal wave transducer to examine the weld metal and heat affected zone on the cast side to the maximum extent practical. In the event that this examination establishes adequate acoustical penetration of the cast material, the staff will require that angle beam ultrasonic examinations be performed on the elbow side using the best available procedures and instrumentation.

5. The staff will continue to evaluate the development of new or improved procedures and will require that these improved procedures be made part of the inservice examination requirements.

G. Relief Request NR-7, Examination Categories B-L-2 and B-M-2, 41 Valve Bodies in the Reactor Coolant, Pressurizer, Safety Injection, and Residual Heat Removal Systems

Code Requirements: Examination category B-L-2, B-M-2, Item B12.40 requires a visual (VT-1) examination of the valve body internal surfaces on valves exceeding 4-in. nominal pipe size. Examinations are limited to one valve within each group of valves that are of the same constructional design, e.g., globe, gate or check valve, manufacturing method and that are performing similar functions in the system, e.g., containment isolation and system overpressure protection.

Code Relief Request: Relief is requested from disassembly of an operable valve for the sole purpose of performing a preservice visual examination (VT-1).

Reason for Request: The requirement to disassemble an operable valve for the sole purpose of performing a visual examination (VT-1) of the internal pressure retaining boundary is impractical and not commensurate to the increased safety achieved by this inspection. Class 1 valves are installed in their respective systems and many have completed functional testing. To disassemble these valves would provide a very small potential for increasing plant safety margins with a very disproportionate impact on expenditures of plant manpower and resources.

The Applicant states that the manufacturer's test data will be used in lieu of a preservice visual examination (VT-1). This includes documentation of examinations performed during fabrication and installation of the subject valves. The examinations performed may include volumetric, surface, and visual examinations, as required by ASME Section II, Material Specifications for Ferrous and Nonferrous Materials.

The Applicant also states that the integrity of the pressure retaining boundary of both carbon steel and stainless steel valve bodies has been excellent. Class 1 valve bodies cannot historically be linked to breaching of the pressure retaining boundary in plant systems. Class 1 valves are subjected to numerous types of nondestructive testing and a rigorous quality assurance program during all stages of fabrication, storage, and installation. These valves have been found acceptable by the manufacturer, the ASME Authorized Nuclear Inspector and Commonwealth Edison's Quality Assurance.

Staff Evaluation: The staff concludes that disassembly of these valves at this time solely to perform the required Section XI preservice visual examination of the internal surface is impractical. The staff has determined that the nondestructive examinations and functional tests performed to date significantly exceed the requirements of the Section XI visual examination and, therefore, these examinations and tests are an acceptable alternative to the Code requirement.

H. Relief Request NR-9, Examination Category B-A, 3 Reactor Pressure Vessel Welds RPVC-WR29, RPVC-WR16 and RPVC-WR7

Code Requirement: The subject Class 1 reactor pressure vessel welds are required to receive a preservice volumetric examination of 100% of the welds in accordance with Table IWB-2500-1, Category B-A, Items B1.11, B1.21, and B1.30.

Code Relief Request: Relief is requested from performing preservice volumetric examination of the inaccessible portions of the subject reactor pressure vessel welds.

Reason for Request: Configuration, permanent attachments and/or structural interferences prohibit 100% ultrasonic examination coverage of the required volume.

1. The lower shell course-to-Dutchman weld RPVC-WR29 has six (6) core barrel-locating lugs welded to the interior surface of the reactor vessel approximately 4.0 in. above the weld. These lugs restricted the automated inspection tool from inspecting the required volume from the shell course side in the areas of the lugs. All of the weld metal was examined from the shell course side where access was available between the lugs. Examinations from the Dutchman side for parallel reflectors covered 100% of the weld metal and heat-affected zone (HAZ). Likewise, 84% of the weld metal and HAZ was examined for transverse reflectors in two opposing directions.

2. The lower disk-to-Dutchman weld RPVC-WR16 has 58 instrument tubes that penetrate the lower disk and physically obstruct the search unit and/or search unit position device. The weld and HAZ received essentially 100% coverage for parallel reflectors from the Dutchman side and for transverse reflectors in two opposing directions. Full coverage for parallel reflectors from the disk side was limited to about 40% of the weld length; partial coverage was achieved on the remainder of the weld.

3. The nozzle shell course-to-flange weld RPVC-WR7 is located just below the tapered portion of the flange which prevents 100% examination of the required adjacent base metal. All of the required volume was inspected for parallel reflectors, manually, from the vessel flange. All of the weld metal and approximately 80% of the adjacent base metal was inspected for transverse reflectors.

4. Drawings and tables defining the specific regions that could not be examined are discussed in the Applicant's letter dated December 14, 1983.

Staff Evaluation: This relief request is acceptable based on the following considerations:

1. All of the reactor pressure vessel welds passed volumetric examinations during fabrication in accordance with the rules of ASME Code Section III for Class 1 components.

2. All of the identified welds will be subject to a system pressure test in accordance with Section XI Class 1 requirements.

3. Accessible portions of the above-listed welds received a preservice volumetric examination in accordance with the ASME Code Section XI.

4. Therefore, the limited Section XI ultrasonic examination, the radiography performed during fabrication and the hydrostatic test provide an acceptable level of preservice structural integrity.

I. Relief Request NR-10, Examination Category B-D, 4 Nozzle-to-Reactor Pressure Vessel Welds, RPVN-A, D, E, and H

Code Requirement: The subject Class 1 reactor pressure vessel nozzle welds are required to receive preservice volumetric examination of 100% of the weld in accordance with Table IWB-2500-1, Category B-D, Item B3.90.

Code Relief Request: Relief is requested from performing preservice volumetric examination of the inaccessible portions of these reactor pressure vessel nozzle welds.

Reason for Request: Nozzle-to-vessel welds on outlet nozzles A, D, E, and H are obstructed by the integral extension from receiving complete ultrasonic examination. The required volume was inspected for parallel reflectors from the inside diameter surface of the nozzle; however, approximately 15% of the required base metal was not inspected for transverse reflectors from the vessel side.

Staff Evaluation: This relief request is acceptable based on the following considerations:

1. All of the reactor pressure vessel nozzle welds passed volumetric examinations during fabrication in accordance with the rules of ASME Code Section III for Class 1 components.

2. All of the identified welds will be subject to a system pressure test in accordance with Section XI Class 1 requirements.

3. Accessible portions of the above-listed welds received a preservice volumetric examination in accordance with ASME Code Section XI.

4. Therefore, the limited Section XI ultrasonic examination, the radiography performed during fabrication and the hydrostatic test provide an acceptable level of preservice structural integrity.

J. Relief Request NR-11, Examination Category C-A, Weld LHXC-01 Chemical and Volume Control, Letdown Heat Exchanger

Code Requirement: This weld is required to receive a volumetric preservice examination in accordance with Table IWC-2500-1, Category C-A, Item C1.10.

Code Relief Request: Relief is requested from performing the Code required ultrasonic circumferential scan for reflectors transverse to the weld seam.

Reason for Request: The circumferential scan could not be performed due to flange bolting extending over the weld crown. An ASME Code Section XI ultrasonic examination for reflectors parallel to the weld seam and an alternative surface examination has been completed.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject weld received radiographic examination and a hydrostatic test during fabrication in accordance with ASME Code Section III requirements.

2. The staff has reviewed the design configuration of the flange, the wall thickness of the shell and the condition of the weld crown and has determined that disassembly of the bolting solely for the purpose of PSI examination would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety. The staff has also determined that the radiography, surface examination and limited ultrasonic examination established an acceptable level of preservice structural integrity.

3. However, in the event the bolted connection is dissassembled for repair or maintenance during service, the staff will require that the preservice examination be performed.

K. Relief Request NR-12, Examination Category C-A, Weld ELHXC-03, Chemical and Volume Control, Excess Letdown Heat Exchanger

Code Requirement: This weld is required to receive a preservice volumetric examination in accordance with Table IWC-2500-1, Category C-A, Item C1.20.

Code Relief Request: Relief is requested from performing ultrasonic examination on the Code required volume.

Reason for Request: Ultrasonic examination of weld ELHXC-03 was limited for approximately 70% of the weld length due to four branch connections welded to the vessel. A liquid penetrant test was performed as an alternative test.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. An alternative surface examination was performed in addition to the limited ultrasonic examination.

2. The ASME Section III radiographic and hydrostatic test along with the limited Section XI ultrasonic examination and alternative surface examination demonstrate an acceptable level of preservice structural integrity.

L. Relief Request NR-13, Examination Category B-D, Inside Radius Section on Pressurizer and Steam Generator Vessel Nozzles (14 Items)

Component Number	Weld Numbers
1RC01BA	Primary Nozzles (2)
1RC01BB	Primary Nozzles (2)
1RC01BC	Primary Nozzles (2)
1RC01BD	Primary Nozzles (2)
1RY01S	PN-1, PN-2, PN-3, PN-4, PN-5, PN-6

Code Requirement: These nozzle inside radii are required to receive a preservice volumetric examination in accordance with Table IWB-2500-1, Category B-D, Items B3.120 and B3.140.

Code Relief Request: Relief is requested from performing the ultrasonic examination on the Code required volume of the nozzle inner radii.

Reason for Request: These nozzles all contain inherent geometric constraints and clad inner surfaces which limit the ability to perform meaningful volumetric examinations. In an attempt to develop a technique to locate flaws in the nozzle inner radii area, a mock-up was used with little success. The only notch which was detectable was the deepest one which penetrated the cladding and extended to a depth of approximately 5/16" into the carbon steel. The steam generator primary side nozzles received an alternative liquid penetrant surface examination.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. All pressure retaining components were hydrostatically tested to the requirements of ASME Section III prior to plant startup.

2. The staff review of the design configuration of the nozzle inner radius has concluded that the Code required volumetric examination is impractical. The staff has determined that performing the ASME Section III hydrostatic test along with the surface examination is an acceptable alternative.

3. The staff will continue to evaluate the development of new or improved procedures and will require that these procedures be made part of the ISI examination requirements.

M. Relief Request NR-14, Examination Category C-B, Steam Generator Vessel (Secondary Side) Nozzles (8 Items) and Residual Heat Exchanger Nozzles (2 Items)

Component Number	Nozzle Number
1RC01BA	SGN-2,3
1RC01BB	SGN-2,3
1RC01BC	SGN-2,3
1RC01BD	SGN-2,3
1RH02AB	RHXN-1,2

Code Requirement: Table IWC-2500-1, of Section XI requires surface and volumetric examination of the regions described in Figure IWC-2500-4 for nozzles in vessels over 1/2 in. nominal thickness. Figure IWC-2500-4 requires volumetric examination of the inner radii on nozzles over 12 in. nominal pipe size.

Code Relief Request: Relief is requested from performing the surface and volumetric examination on the Code required volume of the nozzle inner radii.

Reason for Request: The nozzles listed above contain inherent geometric constraints which limit the ability to perform meaningful ultrasonic examination. The main steam nozzles (SGN-3's) have an internal multiple venturi type flow restrictor. This design does not have a nozzle inner radii as described in Figure IWC-2500-4. This nozzle has seven individual inner radii, corresponding to each venturi, none of which could be examined by ultrasonic examination. The main feedwater nozzles (SGN-2's) also have an internal multiple venturi type flow restrictor but have a thermal sleeve in addition. This design could not be examined due to the geometry of the nozzles internal design.

The Residual Heat Removal Heat Exchanger nozzles are 14 inch diameter and approximately 3/8 inch nominal wall thickness. The Residual Heat Removal Heat Exchanger is approximately 7/8 inch nominal wall thickness. In an attempt to develop a technique to locate flaws in the nozzle inner radii area, a mockup was used with little success. The only notch which was detectable was the deepest one which penetrated the cladding and extended to a depth of approximately 5/16 in. into the carbon steel. Although the nozzles listed above are not internally clad, it was determined by the Applicant that this mockup was representative of the required inspection.

Ultrasonic examination of the above listed nozzle inner radii is not practicable and the inner radii are not accessible to direct contact for surface examination or even remote visual examination.

However, these nozzles have been examined at the point of attachment to the vessel by radiography per ASME Section III, and by ultrasonic examination per ASME Section XI. In addition, a system hydrostatic test, at 125% of the design pressure, has been performed in accordance with ASME Section III.

The above listed main steam and main feedwater nozzles are designed with multiple venturi type flow restrictors to limit flow during a main steam line or main feedwater line break. This design thus enhances the plant's inherent level of safety but does not allow meaningful ultrasonic examination of the nozzles inner radii. However, the increased safety margin afforded by these nozzles makes them a desirable part of plant design.

Staff Evaluation: This relief request is acceptable for PSI based on the following considerations:

1. The subject weld area received radiographic examination and a hydrostatic test during fabrication in accordance with ASME Code Section III requirements. An ultrasonic examination has been performed on the nozzle to vessel welds per ASME Code Section XI requirements.

2. The staff review of the design configuration of the nozzle inner radius has concluded that the Code required volumetric examination is impractical. The staff has determined that the ASME Section III examinations demonstrate an acceptable level of preservice structural integrity.

N. Relief Request NR-15, Examination Category C-C and C-E, 8 Integrally Welded Attachments to Pumps in Containment Spray, Chemical and Volume Control, and Residual Heat Removal Systems

Component Number	Weld Numbers
1CS01PA	CSPE-01, CSPE-02, and CSPE-03
1CY01PA	CVPE-01, CVPE-04
1RH01PA	RHPE-01, RHPE-02, and RHPE-03

Code Requirement: Table IWC-2500-1, Examination Category C-C and C-E, Item C3.70 requires surface examination for integrally welded attachments to pumps.

Code Relief Request: Relief is requested from performing a 100% surface examination of the required areas of each support attachment.

Reason for Request: The required PSI examination was performed on three sides of each attachment, but the fourth side could not be examined due to installed structural support members. The above listed welds connect the support lugs to the pump casings. These integrally welded attachments were examined by the manufacturers using a surface examination technique. In addition, the preservice examination was performed on three sides of each attachment.

The Applicant has proposed a visual (VT-1) examination for the inaccessible portions of these welds.

Staff Evaluation: The staff has determined that the manufacturer's surface examination, the partial preservice examination and the proposed visual examination are an acceptable alternative to the Code requirements.

O. Relief Request Note 5, Examination Category B-L-1, B-M-1, Visual Examination of Reactor Coolant Pump Internal Surfaces

Pumps
1RC01PA
1RC01PB
1RC01PC
1RC01PD

Code Requirement: Table 1WB-2500-1, Category B-L-1, B-M-1, Item B12.10 requires volumetric and surface examination on pump casing welds and Item B12.20 requires visual (VT-1) examination of the pump casing internal surfaces.

Code Relief Request: Relief is requested from performing the Code required visual (VT-1) examination of the pump casing internal surfaces.

Reason for Request: The above-listed pumps are of the integrally cast type and therefore have no pump casing welds. All internal surfaces received liquid penetrant tests performed by the manufacturer. This exceeds the Section XI requirements for visual examination.

Staff Evaluation: The staff has determined that the manufacturer's liquid penetrant examination of all internal surfaces of these pumps exceeds the Section XI requirements for visual examination and, therefore, is an acceptable alternative to the Code requirement.

P. Relief Request Note 11, Examination Categories C-A and C-F, Welds Chemical and Volume Control, Excess Letdown Heat Exchanger; Safety Injection Piping

Component Number	Weld Number
1CV01AA	ELHXC-02
ISI05CB-8"	C-17

Code Requirement: Table IWC-2500-1, Category C-A, Item C1.10, requires volumetric examination of vessel shell circumferential welds. Category C-F, Item C5.21 requires surface and volumetric examination for circumferential welds in piping over 1/2-in. nominal wall thickness.

Code Relief Request: Relief is requested from performing volumetric examination on 100% of the required examination volume due to geometric interferences.

Reason for Request: Weld ELHXC-02 was examined axially for reflectors parallel to the weld seam for approximately 97% of the weld length. There is a 3/4-in. drain connection on the bottom of the shell which prevented complete ultrasonic examination. Weld C-17 was examined axially for reflectors parallel to the weld seam for approximately 90% of the weld length.

There is a pipe which runs perpendicular to 1SI05CB-8" at weld C-17 which obstructed the examination. In addition, weld C-17 received the surface examination required by Item C5.21.

Staff Evaluation: This relief is acceptable based on the following considerations:

1. Welds ELHXC-02 and C-17 received radiographic examinations during fabrication in accordance with ASME Code Section III requirements.

2. Both welds received 100% circumferential ultrasonic examination for reflectors transverse to the weld seam. The axial examination for parallel reflectors exceeded 90% of the required volume.

3. A large portion of the preservice examination required by the ASME Code was performed. Failure to perform a 100% preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity.

IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(2), certain Section XI required preservice examinations are impractical, and compliance with the requirements would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety.

The staff technical evaluation has not identified any practical method by which the existing Byron Station Unit 1 can meet all the specific preservice inspection requirements of Section XI of the ASME Code. Requiring compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Examples of components that would require redesign to meet the specific preservice examination provisions are the reactor vessel and a significant number of the piping and component support systems. Even after the redesign effort, complete compliance with the preservice examination requirements probably could not be achieved. However, the as-built structural integrity of the existing primary pressure boundary has already been established by the construction code fabrication examinations.

Based on the staff review and evaluation, it is concluded that the public interest is not served by imposing certain provisions of Section XI of the ASME Code that have been determined to be impractical. Pursuant to 10 CFR 50.55a(a)(2), relief is allowed from these requirements which are impractical to implement and would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

TECHNICAL EVALUATION REPORT

CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS
BYRON UNITS 1 AND 2
BRAIDWOOD UNITS 1 AND 2
(PHASE I Final)

Docket Nos. 50-454, 50-455, 50-456, and 50-457

Author
S. A. Jensen

Principal Technical Investigator
T. H. Stickley

Revised
April 1984

EG&G Idaho, Inc.
Idaho Falls, Idaho 83415

Prepared for the
U.S. Nuclear Regulatory Commission
Under DOE Contract No. DE-AC07-76ID01570
Fin. No. A6457

ABSTRACT

The Nuclear Regulatory Commission (NRC) has requested that all nuclear plants either operating or under construction submit a response of compliancy with NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." EG&G Idaho, Inc., has contracted with the NRC to evaluate the responses of those plants presently under construction. This report contains EG&G's evaluation and recommendations for Byron/Braidwood for the requirements of Section 5.1.1 of NUREG-0612.

EXECUTIVE SUMMARY

Byron/Braidwood is consistent with the guidelines of NUREG-0612.

CONTENTS

TABLES

CONTROL OF HEAVY LOADS AT NUCLEAR POWER PLANTS

BYRON/BRAIDWOOD

(PHASE I)

1. INTRODUCTION

1.1 Purpose of Review

This technical evaluation report documents the EG&G Idaho, Inc., review of general load-handling policy and procedures at Byron/Braidwood. This evaluation was performed with the objective of assessing conformance to the general load-handling guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants" [1], Section 5.1.1. This constitutes Phase I of a two-phase evaluation.

1.2 Generic Background

Generic Technical Activity Task A-36 was established by the U.S. Nuclear Regulatory Commission (NRC) staff to systematically examine staff licensing criteria and the adequacy of measures in effect at operating nuclear power plants to assure the safe handling of heavy loads and to recommend necessary changes to these measures. This activity was initiated by a letter issued by the NRC staff on May 17, 1978 [2], to all power reactor applicants, requesting information concerning the control of heavy loads near spent fuel.

The results of Task A-36 were reported in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The staff's conclusion from this evaluation was that existing measures to control the handling of heavy loads at operating plants, although providing protection from certain potential problems, do not adequately cover the major causes of load-handling accidents and should be upgraded.

In order to upgrade measures for the control of heavy loads, the staff developed a series of guidelines designed to achieve a two-phase objective using an accepted approach or protection philosophy. The first portion of the objective, achieved through a set of general guidelines identified in NUREG-0612, Article 5.1.1, is to ensure that all load-handling systems at nuclear power plants are designed and operated such that their probability of failure is uniformly small and appropriate for the critical tasks in which they are employed. The second portion of the staff's objective, achieved through guidelines identified in NUREG-0612, Articles 5.1.2 through 5.1.5, is to ensure that, for load-handling systems in areas where their failure might result in significant consequences, either (a) features are provided, in addition to those required for all load-handling systems, to ensure that the potential for a load drop is extremely small (e.g., a single-failure-proof crane) or (b) conservative evaluations of load-handling accidents indicate that the potential consequences of any load drop are acceptably small. Acceptability of accident consequences is quantified in NUREG-0612 into four accident analysis evaluation criteria.

The approach used to develop the staff guidelines for minimizing the potential for a load drop was based on defense in depth and is summarized as follows:

- Provide sufficient operator training, handling system design, load-handling instructions, and equipment inspection to assure reliable operation of the handling system

- Define safe load travel paths through procedures and operator training so that, to the extent practical, heavy loads are not carried over or near irradiated fuel or safe shutdown equipment

- Provide mechanical stops or electrical interlocks to prevent movement of heavy loads over irradiated fuel or in proximity to equipment associated with redundant shutdown paths.

Staff guidelines resulting from the foregoing are tabulated in Section 5 of NUREG-0612.

1.3 Plant-Specific Background

On December 22, 1980, the NRC issued a letter [3] to Commonwealth Edison, the applicant for Byron/Braidwood requesting that the applicant review provisions for handling and control of heavy loads at Byron/Braidwood, evaluate these provisions with respect to the guidelines of NUREG-0612, and provide certain additional information to be used for an independent determination of conformance to these guidelines. On April 7, 1982, Commonwealth Edison provided the initial response [4] to this request. On October 25, 1982, Commonwealth Edison provided additional information in response [9] to a preliminary draft of this report. Further information was provided in submittals [10], [11] dated February 10, 1984, and April 11, 1984.

2. EVALUATION AND RECOMMENDATIONS

2.1 Overview

The following sections summarize Commonwealth Edison's review of heavy load handling at Byron/Braidwood accompanied by EG&G's evaluation, conclusions, and recommendations to the applicant for bringing the facilities more completely into compliance with the intent of NUREG-0612. Commonwealth Edison's review of the facilities does not differentiate between the units. EG&G has evaluated the submittals as though all units are of identical design. The applicant has indicated the weight of a heavy load for this facility (as defined in NUREG-0612, Article 1.2) as 2000 lbs.

2.2 Heavy Load Overhead Handling Systems

This section reviews the applicant's list of overhead handling systems which are subject to the criteria of NUREG-0612 and a review of the justification for excluding overhead handling systems from the above-mentioned list.

2.2.1 Scope

> "Report the results of your review of plant arrangements to identify all overhead handling systems from which a load drop may result in damage to any system required for plant shutdown or decay heat removal (taking no credit for any interlocks, technical specifications, operating procedures, or detailed structural analysis) and justify the exclusion of any overhead handling system from your list by verifying that there is sufficient physical separation from any load-impact point and any safety-related component to permit a determination by inspection that no heavy load drop can result in damage to any system or component required for plant shutdown or decay heat removal."

A. Summary of Applicant's Statements

The applicant's review of overhead handling systems identified the cranes and hoists shown in Table 2.1 as those which handle heavy loads in the vicinity of irradiated fuel or safe shutdown equipment.

The applicant has also identified other cranes that have been excluded from satisifying the criteria of the general guidelines of NUREG-0612.

B. EG&G Evaluation

The applicant appears to have included all applicable handling systems in their tables showing handling for which a load drop could damage equipment.

C. EG&G Conclusions and Recommendations

Based on the information provided, EG&G concludes that the applicant has included all applicable hoists and cranes in their list of handling systems which must comply with the requirements of the general guidelines of NUREG-0612.

TABLE 2.1 CRANE/HOIST SYSTEMS CONSIDERED AS POTENTIAL SOURCES FOR DAMAGE OF SAFETY COMPONENTS.

System Designations
Polar Crane
Cable Tray Drawbridge Winch
Stud Tensioner Hoists (3)
Fuel Building Crane
Spent-Fuel Pit Bridge Crane
Trolley Beam 24
Trolley Beam 25
Trolley Beam 53
Trolley Beam 54
Trolley Beam 23
Trolley Beam 42 (Braidwood only)
Turbine Building Cranes
PTS-2
PTS-3
PTS-4
PTS-5
PTS-8 (Braidwood only)
PTS-9 (Braidwood only)
SG-1
SG-2
SG-3
SG-4

2.3 General Guidelines

This section addresses the extent to which the applicable handling systems comply with the general guidelines of NUREG-0612 Article 5.1.1. EG&G's conclusions and recommendations are provided in summaries for each guideline.

The NRC has established seven general guidelines which must be met in order to provide the defense-in-depth approach for the handling of heavy loads. These guidelines consist of the following criteria from Section 5.1.1 of NUREG-0612:

- Guideline 1--Safe Load Paths
- Guideline 2--Load-Handling Procedures
- Guideline 3--Crane Operator Training
- Guideline 4--Special Lifting Devices
- Guideline 5--Lifting Devices (not specially designed)
- Guideline 6--Cranes (Inspection, Testing, and Maintenance)
- Guideline 7--Crane Design.

These seven guidelines should be satisfied for all overhead handling systems and programs in order to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the spent-fuel pool, or in other areas where a load drop may damage safe shutdown systems. The succeeding paragraphs address the guidelines individually.

2.3.1 Safe Load Paths [Guideline 1, NUREG-0612, Article 5.1.1(1)]

"Safe load paths should be defined for the movement of heavy loads to minimize the potential for heavy loads, if dropped, to impact irradiated fuel in the reactor vessel and in the spent-fuel pool, or to impact safe shutdown equipment. The path should follow, to the extent practical, structural floor members, beams, etc., such that if the load is dropped, the structure is more likely to withstand the impact. These load paths should be defined in procedures, shown on equipment layout drawings, and clearly marked on the floor in the area where the load is to be handled. Deviations from defined load paths should require written alternative procedures approved by the plant safety review committee."

A. Summary of Applicant's Statements

The applicant has evaluated load path locations for Byron/Braidwood. The applicant states that load movement follows the safest and shortest route with the load as close to the floor as possible.

Byron/Braidwood will incorporate into Maintenance/Equipment Removal Procedures references to the applicable M-517 and M-27 prints to identify safe load paths. To the extent necessary, these procedures will be available prior to fuel load. Procedures for heavy load movement inside Containment will incorporate Quality Control or Quality Assurance hold points as necessary and provide independent verification of proper load paths. Crane operators at Byron/Braidwood Stations will move heavy loads under the direction of a maintenance foreman or mechanic. The Byron/Braidwood Stations are presently writing an administrative procedure to describe the job responsibility of the person directing the heavy load movement. Furthermore, the existing maintenance and fuel handling procedures are being revised to reflect the administrative procedure.

B. EG&G Evaluation

The applicant response and drawings submitted indicates that the intent of Guideline 1 criteria have been satisfied at Byron/Braidwood. Load paths have been developed for all heavy loads which have been identified.

The applicant's position on the unfeasibility of marking load paths on the floor is acceptable since a supervisor is present to ensure that the best load path is followed.

C. EG&G Conclusions and Recommendations

EG&G concludes from the applicant's response that the Byron/Braidwood Stations are consistent with the intent of Guideline 1.

2.3.2 Load-Handling Procedures [Guideline 2, NUREG-0612, Article 5.1.1(2)]

"Procedures should be developed to cover load-handling operations for heavy loads that are or could be handled over or in proximity to irradiated fuel or safe shutdown equipment. At a minimum, procedures should cover handling of those loads listed in Table 3-1 of NUREG-0612. These procedures should include: identification of required equipment; inspections and acceptance criteria required before movement of load; the steps and proper sequence to be followed in handling the load; defining the safe path; and other special precautions."

A. Summary of Applicant's Statements

The applicant states that procedures will be developed to cover load-handling operations for the heavy loads identified in Table 3.1-1 of NUREG-0612. These procedures will identify the required equipment, the inspection and acceptance criteria prior to load movement, the steps and

sequence in handling the load, and define the safe load path and other special precautions. They also state that to the extent necessary approved procedures will be in effect prior to fuel loading.

B. EG&G Evaluation

The applicant has stated that load-handling procedures will be developed which will comply with the requirements of Guideline 2. These guidelines should be available for possible review by the NRC prior to fuel loading.

C. EG&G Conclusions and Recommendations

The Byron/Braidwood Stations are consistent with Guideline 2.

2.3.3 Crane Operator Training [Guideline 3, NUREG-0612, Article 5.1.1(3)]

"Crane operators should be trained, qualified, and conduct themselves in accordance with Chapter 2-3 of ANSI B30.2-1976, 'Overhead and Gantry Cranes' [5]."

A. Summary of Applicant's Statements

The applicant states that Byron/Braidwood will comply with ANSI B30.2-1976 with respect to operator training, qualification, and conduct. Training records will be available for inspection and review prior to fuel load.

B. EG&G Evaluation

Byron/Braidwood Stations are consistent with the intent of Guideline 3.

C. <u>EG&G Conclusion and Recommendations</u>

Based on the applicant's statement, Byron/Braidwood is consistent with Guideline 3.

2.3.4 Special Lifting Devices [Guideline 4, NUREG-0612, Article 5.1.1(4)]

"Special lifting devices should satisfy the guidelines of ANSI N14.6-1978, 'Standard for Special Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or More for Nuclear Materials' [6]. This standard should apply to all special lifting devices which carry heavy loads in areas as defined above. For operating plants, certain inspections and load tests may be accepted in lieu of certain material requirements in the standard. In addition, the stress design factor stated in Section 3.2.1.1 of ANSI N14.6 should be based on the combined maximum static and dynamic loads that could be imparted on the handling device based on characteristics of the crane which will be used. This is in lieu of the guideline in Section 3.2.1.1 of ANSI N14.6 which bases the stress design factor on only the weight (static load) or the load and of the intervening components of the special handling device."

A. <u>Summary of Applicant's Statements</u>

The applicant has stated that (a) the lifting devices have been or will be designed in accordance with industrial standards using good engineering practices; (b) special lifting devices for the reactor vessel head and upper internals have been provided by Westinghouse; and (c) Westinghouse used standard quality control procedures in the fabrication of the lifting devices. Both lifting rigs have been designed for 200% of the dead load using AISC allowables and load tested to 125% of their rated load.

In regard to acceptance testing, and maintenance the applicant has made the following statements:

"The Byron and Braidwood Station procedures will comply with the intent of Section 5, Acceptance Testing, Maintenance,

and Assurance of Continued Compliance with some exceptions. In Commonwealth Edison's judgment, the periodic load testing of the special lifting devices to 150% of the maximum load is not practical nor warranted, and may invalidate any vendor product guarantees. As stated in our April 1982 Heavy Load Movement Report, the special lifting devices were load tested to 125%, which is in accordance with the proof-load test indicated on the vendor drawings. Additionally, the logistics of moving heavy test loads into the Reactor Containment Building to accommodate such periodic load testing are difficult.

"Prior to use of specially designed lifting assemblies, visual inspection will be performed and certain critical and accessible parts or members such as hooks and pins will be non-destructively examined at appropriate time intervals. In our judgment, the visual inspection and limited NDE are adequate to detect potential failures.

"However, should an incident occur in which a special lifting device is overloaded, damaged or distorted, an engineering assessment will be performed. This assessment will address ANSI N14.6 and include consideration of the load test up to the original procurement load test value or 150% whichever is less. The requirement to perform this assessment will be incorporated into plant procedures."

B. <u>EG&G Evaluation</u>

Information provided by the applicant indicates that stress design factors are consistent with the intent of ANSI N14.6-1978 for the two special lifting devices identified. The lifting devices mentioned have been load tested to weights substantially in excess of the maximum load currently lifted and, therefore, meet the intent of ANSI N14.6-1978 guidelines for acceptance load testing.

The applicant also states that current procedures meet the intent of Section 5 with some exceptions. The applicant takes exception to periodic performance of load testing. It is noted that ANSI N14.6-1978 provides acceptable alternatives to periodic load-tests if an initial acceptance load test has been satisfactorily performed; the owner may opt to perform an annual (or prior-to-use, depending on frequence of use) series of inspections in accordance with Section 5.3.1(2) of the ANSI standard. This testing shall include "dimensional testing, visual inspection, and nondestructive testing of major load-carrying welds and critical areas." In this regard, the applicant has proposed performance of visual inspections and limited NDE prior to each use of the lifting devices and is of the opinion that such an inspection program is adequate to detect potential failure. Based upon the applicant's statement that the current inspection program is adequate, the degree of load-handling reliability necessary to satisfy periodic inspection requirements of Section 5 has been satisfied. It is recommended that the applicant review requirements for dimensional and nondestructive testing of these lifting devices and modify their inspection program accordingly.

For the remaining exception, the commitment to assess potential damage to the lifting device and determine the need for an overload test to a weight substantially in excess of the rated capacity is consistent with the intent of the ANSI standard.

Since the lifting devices were designed and fabricated by Westinghouse, and were fabricated using Westinghouse's quality control procedures EG&G feels that quality control practices were consistent with the intent of ANSI N14.6.

Based on the above discussion the two special lifting devices mentioned by the applicant meet the intent of ANSI N14.6.

C. EG&G Conclusions and Recommendations

Byron/Braidwood Stations are consistent with the intent of Guideline 4.

2.3.5 Lifting Devices (Not Specially Designed) [Guideline 5, NUREG-0612, Article 5.1.1(5)]

"Lifting devices that are not specially designed should be installed and used in accordance with the guidelines of ANSI B30.9-1971, 'Slings' [7]. However, in selecting the proper sling, the load used should be the sum of the static and maximum dynamic load. The rating identified on the sling should be in terms of the 'static load' which produces the maximum static and dynamic load. Where this restricts slings to use on only certain cranes, the slings should be clearly marked as to the cranes with which they may be used."

A. Summary of Applicant's Statements

The applicant states that all lifting devices were designed according to industrial standards using good engineering practices.

Byron/Braidwood procures and inspects slings to ANSI B30.9-1971. Inspections of slings are conducted annually and slings are examined visually prior to use. Slings are installed and used in accordance with ANSI B30.9-1971. Sling selection is based on the sum of the static and maximum dynamic loads.

Slings are not restricted to special cranes.

The Turbine Building Crane 25 ton Auxiliary Hoist is the only hoist capable of operating faster than 30 fpm. The maximum operating speed is 33.8 fpm. The only safety related component located in the Turbine Bldg. is the SX piping. The SX piping is embedded a minimum of 6 ft under the surface of the basemat and is located three floors below the main turbine floor. Any auxiliary hoist load drop will not effect the SX piping. Additionally, the SX piping is redundant and is separated by a distance of 49 ft-6 in.

The 33.8 fpm does not result in any significant addition of dynamic load and therefore any modification of the hoist speed is not warranted.

B. EG&G Evaluation

The applicant is consistent with this guideline on the basis of the above statements.

The dynamic loads generated by cranes and hoists at Byron/Braidwood are reasonably small percentages of the overall static load and, therefore, may be disregarded when selecting slings.

C. EG&G Conclusions and Recommendations

Byron/Braidwood Stations are consistent with the Guideline 5 of NUREG-0612, based on the previous evaluation.

2.3.6 Cranes (Inspection, Testing, and Maintenance) [Guideline 6, NUREG-0612, Article 5.1.1(6)]

"The crane should be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, 'Overhead and Gantry Cranes,' with the exception that tests and inspections

should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2 for periodic inspection and test, or where frequency of crane use is less than the specified inspection and test frequency (e.g., the polar crane inside a PWR containment may only be used every 12 to 18 months during refueling operations, and is generally not accessible during power operation. ANSI B30.2, however, calls for certain inspections to be performed daily or monthly. For such cranes having limited usage, the inspections, test, and maintenance should be performed prior to their use)."

A. Summary of Applicant's Statements

Cranes will be inspected, tested, and maintained in accordance with Chapter 2-2 of ANSI B30.2-1976, with the exception that tests and inspections should be performed prior to use where it is not practical to meet the frequencies of ANSI B30.2. For cranes having limited usage, the inspections and tests will be performed prior to their use. Approved procedures will be in effect prior to fuel load.

B EG&G Evaluation

The applicant states that crane inspection, testing, and maintenance programs will be in accordance with ANSI B30.2-1976, with exceptions as allowed by Guideline 6.

C. EG&G Conclusions and Recommendations

Byron/Braidwood Station's are consistent with Guideline 6 on the basis of the applicant's statement.

2.3.7 Crane Design [Guideline 7, NUREG-0612, Article 5.1.1(7)]

"The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of ANSI B30.2-1976, 'Overhead and

Gantry Cranes,' and of CMAA-70, 'Specifications for Electric Overhead Traveling Cranes' [8]. An alternative to a specification in ANSI B30.2 or CMAA-70 may be accepted in lieu of specific compliance if the intent of the specification is satisfied."

A. Summary of Applicant's Statements

The polar cranes, turbine building cranes, and fuel-handling building cranes were designed in accordance with the 1975 Revision of CMAA-70 and ANSI B30.2-1976. Welding was performed in accordance with AWS D.1.1. The turbine building cranes were also designed and fabricated in accordance with CMAA-70, 1975 Revision and ANSI B30.2 1976.

The polar crane is provided with limit switches for bridge overtravel, plus two upper and one lower limit switch for each hoist. Mechanical end stops are also provided on the bridge.

The Fuel-Handling Building Crane is provided with end stops on the runways and bridge, plus upper and lower limit switches on both hoists.

The trolley beams were designed and fabricated in accordance with AISC-1978 standards. The PTS and single-girder systems (SG) were designed in accordance with MMA and AISC-1978 standards. The jib cranes were designed and fabricated according to AISC-1978 standards.

B. EG&G Evaluation

The cranes mentioned by the applicant in their response are consistent with the intent of Guideline 7 based on the applicant's statements.

C. EG&G Conclusions and Recommendations

Byron/Braidwood Stations are consistent with the intent of Guideline 7 on the basis of the applicant's statements.

3. CONCLUDING SUMMARY

3.1 Applicable Load-Handling Systems

The list of cranes and hoists supplied by the applicant as being subject to the provisions of NUREG-0612 is adequate (see Section 2.2.1).

3.2 Guideline Recommendations

Compliance with the seven NRC guidelines for heavy load handling (Section 2.3) are partially satisfied at Byron/Braidwood. This conclusion is represented in tabular form as Table 3.1. Specific recommendations to aid in compliance with the intent of these guidelines are provided as follows:

Guideline	Recommendation
1. (Section 2.3.1)	a. Define the duties of supervisors with respect to heavy load handling.
2. (Section 2.3.2)	a. Byron/Braidwood are consistent with this guideline.
3. (Section 2.3.3)	a. Byron/Braidwood are consistent with this guideline.
4. (Section 2.3.4)	a. Byron/Braidwood are consistent with the intent of this guideline.
5. (Section 2.3.5)	a. Byron/Braidwood are consistent with the intent of this guideline.
6. (Section 2.3.6)	a. Byron/Braidwood are consistent with this guideline
7. (Section 2.3.7)	a. Byron/Braidwood are consistent with this guideline

TABLE 3.1. BYRON/BRAIDWOOD NUREG COMPLIANCE MATRIX

			Guidelines						
			1	2	3	4	5	6	7
Equipment Designation	Heavy Loads	Weight or Capacity (Tons)	Safe Load Paths	Procedures	Crane Operator Training	Special Lifting Devices	Slings	Crane Test and Inspection	Crane Design
Polar Crane	Reactor Vessel Head, 411,750 lb	230/40	C	C	C	C	C	C	C
	Reactor Upper Internals, 145,000 lb								
	Reactor Lower Internals, 269,600 lb								
	Reactor Coolant Pump Motors, 77,500 lb								
	Reactor Core Barrel Assembly, 217,300 lb								
	Main Hook Lower Load Block, 6,783 lb								
	Auxiliary Hook Lower Load Block, 1,770 lb								
Cable Tray Drawbridge Winch	Cable Tray Drawbridge, 9,000 lb	10	C	C	C	N/A	C	C	C
Stud Tensioner Hoists (3)	Reactor Vessel Head Stud Tensioner, N/A	2	C	C	C	N/A	C	C	C
	Reactor Vessel Head Studs, 806 lb								
Fuel Building Crane	Spent-Fuel Cask, 218,000 lb (IN-12)	125	C	C	C	N/A	C	C	C
	Fuel Assembly, 1,467 lb								
	(Main Hoist Lower Load Block, 5,600 lb								

TABLE 3.1. (continued)

Equipment Designation	Heavy Loads	Weight or Capacity (Tons)	Guidelines 1 Safe Load Paths	2 Procedures	3 Crane Operator Training	4 Special Lifting Devices	5 Slings	6 Crane Test and Inspection	7 Crane Design
	Auxiliary Hoist Lower Load Block, (1,500 lb est.)								
	Failed-Fuel Cannister, 940 lbs								
	Control Rod Cluster, 158 lbs								
Spent Fuel Pit Bridge Crane	New Fuel Assembly, 1,467 lb	2	C	C	C	C	C	C	C
	Spent-Fuel Assembly, 1,467 lb								
	Fuel-Handling Tools, 375 lb maximum								
	Failed-Fuel Cannister, 940 lb								
	Control Rod Cluster, 158 lb								
Trolley Beam 24	RHR Heat Exchangers	12	C	C	C	N/A	C	C	C
	Tube Bundle, 14,500 lb								
	Concrete Plugs, 15,000 lb								
Trolley Beam 25	RHR Heat Exchangers	12	C	C	C	N/A	C	C	C
	Tube Bundle, 14,500 lb								
	Concrete Plugs, 15,000 lb								
Trolley Beam 53	Charging Pump, 7,500 lb	8	C	C	C	N/A	C	C	C

TABLE 3.1. (continued)

Equipment Designation	Heavy Loads	Weight or Capacity (Tons)	Guidelines 1 Safe Load Paths	2 Procedures	3 Crane Operator Training	4 Special Lifting Devices	5 Slings	6 Crane Test and Inspection	7 Crane Design
	Charging Pump Motor, 4,345 lb								
Trolley Beam 54	Charging Pump, 7,500 lb	8	C	C	C	N/A	C	C	C
	Charging Pump and Motor, 4,325 lb								
SG-1	Diesel Generator	2	C	C	C	N/A	C	C	C
	Cylinder Head Covers, 830 lb								
SG-2	Diesel Generator	2	C	C	C	N/A	C	C	C
	Cylinder Head Covers, 830 lb								
SG-3	Diesel Generator	2	C	C	C	N/A	C	C	C
	Cylinder Head Covers, 830 lb								
SG-4	Diesel Generator	2	C	C	C	N/A	C	C	C
	Cylinder Head Covers, 830 lb								
PTS-2 and	Concrete Plugs, 11,700 lb	6	C	C	C	N/A	C	C	C
PTS-3 (Unit 2)	Containment Spray Pump/Motor, 7,307 lb								
	Charging Pump, 7,500 lb								
	Safety Injection Pump, 5,260 lb								
	Charging Pump Motor, 4,345 lb								

TABLE 3.1. (continued)

Equipment Designation	Heavy Loads	Weight or Capacity (Tons)	Guidelines 1 Safe Load Paths	2 Procedures	3 Crane Operator Training	4 Special Lifting Devices	5 Slings	6 Crane Test and Inspection	7 Crane Design
	Safety Injection Pump Motor, 4,345 lb								
PTS-4 and	Safety Injection Pump, 5,260 lb	6	C	C	C	N/A	C	C	C
PTS-5 (Unit 2)	Safety Injection Pump Motor, 3,100 lb								
Trolley Beam 23	Charging Pump 7,500 lb	10	C	C	C	N/A	C	C	C
	Containment Spray Pump/Motor, 7,307 lb								
	RHR Pump/Motor, 6,200 lb								
	Safety Injection Pump, 5,260 lb								
	Safety Injection Motor, 4,345 lb								
	ESW Pump, 9,500 lb								
	ESW Motor, 12,000 lb								
Turbine Building Cranes Unit 1 (*Unit 2)	Turbine Components	125/25	C	C	C	N/A	C	C	C
	LP Spindles, 294,000 lb								
	HP Spindles, 131,000 lb	148/25*							
	HP Cylinder Cover, 166,000 lb								
	LP Cylinder Cover, 172,300 lb								
	Other Lighter Loads								

TABLE 3.1. (continued)

Equipment Designation	Heavy Loads	Weight or Capacity (Tons)	Guidelines 1 Safe Load Paths	2 Procedures	3 Crane Operator Training	4 Special Lifting Devices	5 Slings	6 Crane Test and Inspection	7 Crane Design
PTS-8 and PTS-9	Circulating Water Pump Motor, 75,000 lb	30	C	C	C	N/A	C	C	C
Trolley Beam 42	WS Pump, 41,300 lb	12	C	C	C	N/A	C	C	C
	WS Motor, 22,500 lb								

C = Applicant action complies with NUREG-0612 Guideline.
NC = Applicant action does not comply with NUREG-0612 Guideline.
R = Applicant has proposed revisions/modifications designed to comply with NUREG-0612 Guideline.
I = Insufficient information provided by the Applicant.

4. REFERENCES

1. NUREG-0612, Control of Heavy Loads at Nuclear Power Plants, NRC.

2. V. Stello, Jr. (NRC), Letter to all applicants. Subject: Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 17 May 1978.

3. USNRC, Letter to Commonwealth Edison. Subject: NRC Request for Additional Information on Control of Heavy Loads Near Spent Fuel, NRC, 22 December 1980.

4. Commonwealth Edison, Letter to Director of Nuclear Reactor Regulation. Subject: Byron Station Units 1 and 2, Braidwood Station Units 1 and 2, 7 April 1982.

5. ANSI B30.2-1976, "Overhead and Gantry Cranes".

6. ANSI N14.6-1978, "Standard for Lifting Devices for Shipping Containers Weighing 10,000 Pounds (4500 kg) or more for Nuclear Materials".

7. ANSI B30.9-1971, "Slings".

8. CMAA-70, "Specifications for Electric Overhead Traveling Cranes".

9. Commonwealth Edison, Letter to Director of Nuclear Reactor Regulation. Subject: Byron Station Units 1 and 2, Braidwood Station Units 1 and 2, Control of Heavy Loads, October 25, 1982.

10. Commonwealth Edison, Letter to Director of Nuclear Reactor Regulation. Subject: Byron Station Units 1 and 2, Braidwood Station Units 1 and 2, Supplemental Information to the Resolution of "Control of Heavy Loads a Nuclear Power Plants," February 10, 1984.

11. Commonwealth Edison, Letter to Director of Nuclear Reactor Regulation. Subject: Byron Station Units 1 and 2, Braidwood Station Units 1 and 2, Supplemental Information to the Resolution of "Control of Heavy Loads a Nuclear Power Plants," April 11, 1984.

23099

NRC FORM 335 (6-83) U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET**	1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any) NUREG-0876 Supplement No. 5
	2. Leave blank
3. TITLE AND SUBTITLE Safety Evaluation related to the operation of Byron Station, Units 1 and 2	4. RECIPIENT'S ACCESSION NUMBER
	5. DATE REPORT COMPLETED MONTH October YEAR 1984
6. AUTHOR(S)	7. DATE REPORT ISSUED MONTH October YEAR 1984
8. PERFORMING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) Division of Licensing Office of Nuclear Reactor Regulation U. S. Nuclear Regulatory Commission Washington, D. C. 20555	9. PROJECT/TASK/WORK UNIT NUMBER
	10. FIN NUMBER
11. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code) Same as 8. above	12a. TYPE OF REPORT Technical
	12b. PERIOD COVERED (Inclusive dates) May 1984 - October 1984

13. SUPPLEMENTARY NOTES

Docket Nos. STN 50-454 and STN 50-455

14. ABSTRACT (200 words or less)

Supplement No. 5 to the Safety Evaluation Report related to Commonwealth Edison Company's application for licenses to operate the Byron Station, Units 1 and 2 located in Rockvale Township, Ogle County, Illinois, has been prepared by the Office of Nuclear Reactor Regulation of the U. S. Nuclear Regulatory Commission. This supplement addresses open items that had not been resolved at the time of publication of Supplement No. 4.

15a. KEY WORDS AND DOCUMENT ANALYSIS

15b. DESCRIPTORS

16. AVAILABILITY STATEMENT	17. SECURITY CLASSIFICATION (This report)	18. NUMBER OF PAGES
Unlimited	UNCLASSIFIED	
	19. SECURITY CLASSIFICATION (This page) UNCLASSIFIED	20. PRICE $

431-02-0408
- Box 20

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FIRST CLASS MAIL
POSTAGE & FEES PAID
USNRC
WASH. D.C.
PERMIT No. G-67