NUREG-0954
Supplement No. 2

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

Docket Nos. 50-413 and 50-414

Duke Power Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

June 1984

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ABSTRACT

This report supplements the Safety Evaluation Report (NUREG-0954) issued in February 1983 and Supplement 1 issued in April 1983 by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission with respect to the application filed by Duke Power Company, North Carolina Municipal Power Agency Number 1, North Carolina Membership Corporation, and Saluda River Electric Cooperative, Inc. as applicants and owners, for licenses to operate the Catawba Nuclear Station, Units 1 and 2 (Docket Nos. 50-413 and 50-414, respectively). The facility is located in York County, South Carolina, approximately 9.6 km (6 mi) north of Rock Hill and adjacent to Lake Wylie. This supplement provides more recent information regarding resolution or updating of some of the open and confirmatory issues and license conditions identified in the Safety Evaluation Report.

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1 INTRODUCTION AND DISCUSSION

1.1 Introduction

In February 1983, the Nuclear Regulatory Commission staff (NRC or staff) issued a Safety Evaluation Report (NUREG-0954) regarding the application by Duke Power Company, North Carolina Municipal Power Agency Number 1, North Carolina Electric Membership Corporation, and Saluda River Electric Cooperative, Inc. (the applicant or Duke) for licenses to operate the Catawba Nuclear Station, Units 1 and 2. The Safety Evaluation Report (SER) was supplemented in April 1983 by Supplement 1 (SSER 1), which documented the resolution of several outstanding and confirmatory issues and license conditions in further support of the licensing activities. This report is Supplement 2 to that Safety Evaluation Report (SER).

This supplement provides more recent information regarding resolution or update of some of the outstanding and confirmatory issues and license conditions identified in the SER and its supplement.

Each of the following sections or appendices of this supplement is numbered the same as the section or appendix of the SER that is being updated, and the discussions are supplementary to and not in lieu of the discussion in the SER and SSER 1 unless otherwise noted. Accordingly, Appendix A is a continuation of the chronology of the safety review. Appendix B is an updated bibliography.* Appendix D is a list of principal contributors to this supplement. No changes in SER Appendix C have been made by this supplement.

The Project Manager is Dr. Kahtan N. Jabbour. Dr. Jabbour may be contacted by calling (301) 492-7800 or by writing to the following address:

Dr. Kahtan N. Jabbour
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, DC 20555

1.7 Summary of Outstanding Issues

SER Section 1.7 identified 18 outstanding issues that had not been resolved at the time the SER was issued. This supplement updates the status of those items. The current status of each of the 18 original issues is tabulated below. For those items discussed in this supplement, the relevant section(s) of this document is (are) indicated. Resolution of those issues that are, to date, unresolved will be addressed in future supplements.

*Availability of all material cited is described on the inside front cover of this report.

Issue	Status	Section(s)
(1) Conformance with SECY 82-352 with regard to quality assurance in design and construction of nuclear projects	Under review	--
(2) Performance of the SNSW pond using NUREG-0693	Resolved (SSER 2)	2.4.4.2
(3) Inservice pump and valve testing program	Changed to License Condition 35 (SSER 2)	3.9.6
(4) Seismic and environmental qualification of equipment	(a) Seismic qualification--changed to License Condition 38 (SSER 2)	3.10
	(b) Environmental qualification--awaiting information	--
(5) Thermal design procedures and flow measurements techniques	Resolved (SSER 2)	4.4.3.3
(6) Instrumentation for inadequate core cooling detection (II.F.2)	Changed to License Condition 5 (SSER 2)	4.4.3.4
(7) Pressurizer safety valve sizing and low-temperature overpressure protection	Resolved (SSER 2)	5.2.2.1, 5.2.2.2
(8) Model D steam generator preheater degradation	(a) Resolved for Catawba Unit 1 (SSER 2)	5.4.2.3
	(b) Under review for Catawba Unit 2	--
(9) Conformance to the staff's position on design requirements of the RHRS and steam generator tube rupture	Changed to License Conditions 36 and 37 (SSER 2)	5.4.4, 15.4.4
(10) Lockout of manual control by the load sequencer and ECCS override and reset	Resolved (SSER 2)	7.3.2.11, 6.3.2
(11) Remote shutdown instrumentation and controls	Resolved (SSER 1)	7.4.2.2
(12) Loss of both RHR trains resulting from a single instrument bus failure	Resolved (SSER 2)	7.4.2.4

Issue	Status	Section(s)
(13) Power lockout to motor-operated valves	Resolved (SSER 2)	7.6.2.6, 8.4.4
(14) Fire protection program	Partially resolved (SSER 2)	9.5.1
(15) Diesel generators emergency lighting, air intake and exhaust, and inadvertent operation of fire protection system in diesel generator buildings	Resolved (SSER 2)	9.5.3, 9.5.8, 9.5.4.1
(16) Emergency planning and related meteorology	Changed to Confirmatory Issue 42 (SSER 2)	13.3, 2.3.3
(17) Alarm in control room for boron dilution modes in all modes of operation	Under review	--
(18) Control room design review	Changed to License Condition 33 (SSER 2)	18

1.8 Confirmatory Issues

SER Section 1.8 identified 41 confirmatory issues for which additional information and documentation were required to confirm preliminary conclusions. This supplement updates the status of those items for which the confirmatory information has subsequently been provided by the applicant and for which review has been completed by the staff. The current status of each of the original issues is tabulated below. For those items discussed in this supplement, the relevant section of this supplement is noted. Resolution of issues that are outstanding, to date, will be addressed in future supplements.

Issue	Status	Section
(1) Probable maximum precipitation and its effects on safety-related structures and components	Resolved (SSER 2)	2.4.3.2
(2) Sediment accumulation in SNSW pond intake structures	Resolved (SSER 1)	2.4.4.2
(3) Postulated failure of CCW piping and its effects on permanent dewatering system and adjacent buildings	Resolved (SSER 1)	2.4.5
(4) Amplified seismic design spectra for NSW pipelines and diesel fuel oil tanks	Resolved (SSER 1)	2.5.2.3

Issue	Status	Section
(5) Dynamic stability of the SNSW pond dam under extreme loading conditions	Resolved (SSER 1)	2.5.4
(6) SSI for buildings not founded on rock	Resolved (SSER 2)	3.7.3
(7) Structural integrity of safety-related masonry walls	Resolved (SSER 1)	3.8
(8) Vertical seismic response spectra	Resolved (SSER 1)	3.9.2
(9) Loose-parts monitoring systems	Resolved (SSER 2)	4.4.3.1
(10) Listing of ASME Code Cases used in the construction of Section III, Class 1 components within the RCPB	Resolved (SSER 2)	5.2.1.2
(11) Preservice inspection program	Resolved (SSER 2)	5.2.4, 6.6
(12) Main steamline break using a revised heat transfer model	Awaiting information	--
(13) Subcompartment analysis	Resolved (SSER 2)	6.2.1.2
(14) Minimum containment pressure analysis	Resolved (SSER 2)	6.2.1.3
(15) Design provisions for containment isolation systems	Resolved (SSER 2)	6.2.4
(16) Containment purge system	Under review	--
(17) Justification for not testing certain isolation valves	Under review	--
(18) Fracture prevention of containment pressure boundary	Awaiting information	--
(19) Compatibility of ECCS valve interlocks	Resolved (SSER 2)	6.3.2
(20) Postaccident environmental conditions and their impact on the ability of the operator to complete certain actions outside the control room	Resolved (SSER 2)	6.3.2
(21) Procedure for resetting ECCS after SIS (ECCS override and reset)	Resolved (SSER 2)	6.3.2

Issue	Status	Section
(22) NPSH analysis	Resolved (SSER 2)	6.3.4
(23) Inside-containment insulation and containment sump test	Resolved (SSER 2)	6.3.4
(24) LOCA sensitivity analysis	Resolved (SSER 2)	6.3.5.1
(25) Steam generator level control and protection	Resolved (SSER 2)	7.3.2.1
(26) Compliance with IE Bulletin 80-06	Resolved (SSER 2)	7.3.2.2
(27) Test of engineered safeguards P-4 interlock	Resolved (SSER 2)	7.3.2.7
(28) Containment pressure control system	Resolved (SSER 2)	7.3.2.10
(29) Remote shutdown instrumentation and controls	Awaiting information	--
(30) Control switches for RHR miniflow valves	Resolved (SSER 2)	7.4.2.5
(31) Instrumentation used to initiate safety functions	Resolved (SSER 2)	7.5.2.5
(32) Interlocks for reactor coolant system pressure control during low temperature operation	Resolved (SSER 1)	7.6.2.1
(33) Upper head injection manual control	Resolved (SSER 2)	7.6.2.3
(34) Key-locked switches used to override isolation of control room area HVAC system	Resolved (SSER 2)	7.6.2.4
(35) Separation of field run cables	Resolved (SSER 2)	8.4.5
(36) Flooding of electrical equipment as a result of a LOCA	Resolved (SSER 2)	8.4.7
(37) Load sequencer accelerated sequence	Resolved (SSER 2)	8.4.8
(38) 100% load reduction capability	Under review	--
(39) Improved thermal design method	Deleted (SSER 2)	15.1
(40) Locked rotor accident	Resolved (SSER 2)	15.3.4

Issue	Status	Section
(41) ESF grade containment purge filter system design	Resolved (SSER 2)	15.4.6
(42) Emergency planning and related meteorology	Added in SSER 2	13.3, 2.3.3

1.9 License Conditions

SER Section 1.9 identified 33 issues for which license conditions may be desirable to ensure that staff requirements are met during plant operation. The license condition may be in the form of a condition in the body of the operating licenses, or a requirement in the Technical Specifications appended to the licenses. The license conditions are tabulated below, with the relevant section of this report noted for the updated condition. License Conditions (8), (9), (15), (21), and (28) were resolved in the SER and should not have been included in Section 1.9 of the SER.

Issue	Status	Section
(1) Turbine system maintenance program	Unchanged (SER)	3.5.1.3
(2) Shift technical advisor (I.A.1.1)	Resolved (SSER 2)	13.5.1.3
(3) Relief and safety valve testing (II.D.1)	Resolved (SSER 2)	3.9.3.2
(4) Control and shutdown rods surveillance requirements	Resolved (SSER 2)	4.2
(5) Instrumentation for inadequate core cooling detection (II.F.2)	Unchanged (SSER 2)	4.4.3.4
(6) Inservice inspection program	Unchanged (SSER 2)	5.2.4, 6.6
(7) Installation of reactor coolant vents (II.B.1)	Under review	--
(8) Accident monitoring instrumentation (II.F.1)	Resolved (SER Section 11.5)	--
(9) Containment isolation dependability (II.E.4.2)	Resolved (SER Section 6.2.4)	--
(10) Hydrogen control measure	Unchanged (SSER 2)	6.2.5
(11) ECCS flow measurements and NPSH verification	Under review	--
(12) Charging pumps deadheading	Resolved (SSER 2)	6.3.2

Issue	Status	Section
(13) Effect of nonseismic piping on safety injection pumps' miniflow lines	Resolved (SSER 2)	6.3.1
(14) PORV isolation system (II.K.3.1, II.K.3.2)	Resolved (SSER 2)	7.6.2.6, 15.5.3
(15) Low-temperature overpressure protection/power supplies for pressurizer relief valves and level indicators (II.G.1)	Resolved (SER Section 8.4.12)	--
(16) Compliance with NUREG-0612	Under review	--
(17) Postaccident sampling system (II.B.3)	Unchanged (SSER 2)	9.3.2.2
(18) Internal corrosion protection for fuel oil storage tanks	Unchanged (SER)	9.5.4.2
(19) Secondary water chemistry monitoring and control program	Resolved (SSER 2)	10.3.4
(20) Loss of primary source of condensate storage water	Resolved (SSER 2)	10.4.9
(21) Primary coolant outside containment (III.D.1.1)	Resolved (SER Section 11.6)	--
(22) Independent safety engineering group (I.B.1.2)	Technical Specifications (6.2.3.1, 6.2.3.2, 6.2.3.3, 6.2.3.4)	None
(23) Emergency preparedness	Changed to Confirmatory Issue 42 (SSER 2)	13.3
(24) Control room access (I.C.4)	Resolved (SSER 2)	13.5.1.3
(25) NSSS vendor review of low power testing and power ascension procedures (I.C.7)	Unchanged (SSER 2)	13.5.3
(26) Pilot monitoring of selected emergency procedures for near-term operating license applicants (I.C.8)	Deleted (SSER 2)	13.5.2
(27) Implementation and maintenance of physical security plan	Unchanged (SER)	13.6
(28) Report on outages of emergency core cooling system (II.K.3.17)	Resolved (SER Section 13.5.4)	--

Issue	Status	Section
(29) Effect of high pressure injection for small break LOCA with no auxiliary feedwater (II.K.2.13)	Resolved (SSER 2)	15.5.1
(30) Voiding in the reactor coolant system (II.K.2.17)	Resolved (SSER 2)	15.5.2
(31) Anticipatory reactor trip (II.K.3.10)	Unchanged (SER)	5.2.2
(32) Revised small-break LOCA analysis (II.K.3.30, II.K.3.31)	Resolved	15.5.6
(33) Control room design review (I.D.1)	Partially resolved	18
(34) Short-term accident analysis and procedures revision (I.C.1)	Added in SSER 2	13.5.2
(35) Inservice pump and valve testing program	Added in SSER 2	3.9.6
(36) Design requirements of RHRS	Added in SSER 2	5.4.4
(37) Steam generator tube rupture analysis	Added in SSER 2	15.4.4
(38) Seismic qualification of equipment	Added in SSER 2	3.10

2 SITE CHARACTERISTICS

2.3 Meteorology

2.3.3 Onsite Meteorological Measurements Program

In the SER, the staff indicated that the operational meteorological measurements program would be used as part of the overall emergency response capability and that the operational program would be reviewed during the staff's evaluation of the applicant's emergency response capability. This evaluation was made through the Emergency Planning Implementation Appraisal (EPIA) conducted at Catawba during November 8-18, 1983, and through subsequent followup inspections.

The applicant discontinued the preoperational meteorological measurements program at Catawba in February 1978. Although some data were collected after that time, the applicant did not adequately maintain or calibrate the measurements system to meet the accuracy specifications of RG 1.23. The operational program will be essentially the same as the preoperational program, and the applicant has committed that the meteorological measurements program at Catawba will be operational and calibrated before fuel loading (see the April 10, 1984, letter from H. B. Tucker (Duke) to J. O'Reilly (NRC)).

Any deficiencies in the operational meteorological measurements program or in the use of meteorological information in emergency response that were identified through the EPIA or followup inspections are being tracked by the staff.

The staff finds the applicant's commitment in this matter acceptable, and therefore, this issue has been changed to Confirmatory Issue 42. Additionally, a postimplementation review of the use of meteorological information for emergency response at Catawba will be conducted as part of the evaluation of the emergency response facilities in accordance with the provisions of Supplement 1 to NUREG-0737.

2.4 Hydrologic Engineering

2.4.3 Flood Potential

2.4.3.2 Local Intense Precipitation

In the SER the staff stated that it had not reviewed the applicant's revised analysis of local flooding. Subsequent to publication of the SER, the staff requested that the applicant reanalyze potential flooding from a probable maximum precipitation (PMP) event using Hydrometeorological Report (HMR) No. 51 (U.S. National Oceanic and Atmospheric Administration, 1978) and HMR No. 52 (U.S. National Weather Service, 1982). The reason for this request was because HMR No. 51 has superceded HMR No. 33 (U.S. Weather Bureau, 1956) which had been used by the applicant to obtain the 6-hour, 12-hour, and 24-hour precipitation values, and HMR No. 52 is a more appropriate reference for distributing the

6-hour PMP into smaller time increments. The applicant had used EM 1110-2-1411 (Department of the Army, 1952) for temporal distribution of the PMP. The applicant responded to the staff's request in a letter dated February 1, 1984.

The Catawba station yard drainage system is designed for a rainfall intensity of 4.0 in. per hour. This is less than the PMP; so during the PMP event some water could pond on the site.

PMP is the estimated depth of precipitation (rainfall) for which there is virtually no risk of exceeding. The PMP values used by the applicant were determined from HMR No. 51 and HMR No. 52 as requested by the staff. First the applicant estimated a 6-hour PMP value of 30.1 in. from HMR No. 51. This 6-hour PMP was then multiplied by rainfall percentages given in HMR No. 52 for 5-, 15-, 30-, and 60-min intervals. Next the applicant estimated rainfall values for each 5-min interval during the peak 1-hour rainfall. The resulting 5-min rainfall values were then arranged as follows:

Interval (minutes)	Incremental PMP (inches)
0-5	0.35
5-10	0.80
10-15	1.05
15-20	1.16
20-25	1.61
25-30	2.02
30-35	6.18
35-40	1.49
40-45	1.60
45-50	1.14
50-55	0.95
55-60	0.65

Using these PMP values, the applicant determined that water could pond on site to an evaluation of 594.59 ft MSL. Because some of the entrances to safety-related structures are 0.59 ft lower at an elevation of 594.0 ft MSL, water could enter some buildings. The staff, in an independent analysis, determined a PMP ponding level of 594.65 ft MSL. Because the difference between the two calculated levels (0.06 ft) is within the allowable 5% margin discussed in SRP Section 2.4.2, the staff concludes that the PMP ponding level determined by the applicant is conservative and acceptable as a basis for determining whether a PMP event would affect the safety of the plant.

The site area will be graded as shown on Figure 2.4.2-1 of the FSAR. To drain the site, overflow areas will be provided to the northeast and south of the powerhouse yard. The applicant determined that these overflow areas should have a total width of 913 ft. The staff agrees that this total overflow width is adequate to ensure that water does not pond to an elevation in excess of 594.6 ft MSL as determined by the applicant. To prevent water from flowing into the powerhouse yard area from the switch yard and cooling tower yard, earth berms surrounding critical portions of these areas will be provided as shown on FSAR Figure 2.4.2-1.

Doors where water could enter safety-related buildings are shown on Figure 2.4.2-3 of the FSAR. As shown on this figure, the Units 1 and 2 diesel generator buildings have concrete curbs at their entrances. These curbs have a top elevation of 594.63 ft MSL. Because this is higher than the PMP level of 594.59 ft MSL, the staff concludes that water from a PMP event will not enter either of the diesel generator buildings. The applicant states that all doors entering the Units 1 and 2 auxiliary building (electrical penetration rooms), outside doghouses, upperhead injection (UHI) buildings, and the auxiliary service building, are equipped with automatic closures and security hardware. These doors are accessible only by magnetic key and are continuously monitored in the security control room. Therefore, in determining the amount of water that would enter safety-related buildings during a PMP event, the applicant assumed that all doors would be closed and leakage into the buildings would only be through the cracks under the doors. The applicant states that if water entered the buildings, it would spread across the floor and be intercepted by the floor drain system to be routed to four floor drain sumps and a floor drain tank, all located in the auxiliary building.

The staff has reviewed the applicant's analysis and agrees that because doors to safety-related buildings are normally closed, only the small amount of water that could leak under the closed doors during a PMP will enter safety-related structures. The staff agrees with the estimates of volume and flow of water that the applicant determined would leak into safety-related buildings. In addition, the staff has determined that the floor drains shown in FSAR Figure 2.4.2-3 have the capability of intercepting all the water that leaks in underneath the doors. Thus, the staff concludes that there would be no ponding at grade level of 594.0 ft MSL inside safety-related buildings during a PMP event.

The applicant conservatively assumed that there would be no pumping from the floor drain sumps or from the floor drain tank. On this basis, the applicant determined that there would be some ponding as follows:

Area	Maximum Depth of Ponding
Units 1 and 2 auxiliary feedwater pump room and shutdown panel room at el 543.0 ft MSL	4 in. (outside pits)
Units 1 and 2 outside doghouse at el 577.0 ft MSL	3 in.
Units 1 and 2 UHI building at el 550.0 ft MSL	4 in.
Floor drain tank room at el 543.0 ft MSL	2 in.
Waste evaporator package room at el 537.0 ft MSL	3 ft-3 in.
Chemical drain tank and pump room at el 537.0 ft MSL	6 ft

Section 3.4.1 of this report contains a discussion related to the effects of the resulting water levels from the PMP event on safety-related equipment.

The applicant also considered the possibility of water entering safety-related buildings through the turbine building. Because the turbine building is not a safety-related building, security hardware and procedures are not required to maintain exterior entrances in a closed position. Thus, all the doors entering the turbine building were conservatively assumed to be open during the entire PMP event. As is the case with safety-related buildings, water that enters the turbine building at an elevation of 594.0 ft MSL would spread across the floor to be intercepted by the floor drain system and numerous large openings in the floor slab to be routed to the basement level of the turbine building at elevation 568.0 ft MSL. Neglecting any pumping, the water would pond to a depth of 6 in. to an elevation of 568.5 ft MSL. A concrete barrier at this level with a top elevation of 576.0 ft MSL would prevent water from entering safety-related buildings through the turbine building.

The staff has reviewed the applicant's analysis and concludes that during a PMP event water could pond to a level about 0.6 ft higher than some entrances to some safety-related buildings. The staff further concludes that because exterior doors will be normally closed, the amount of ponded water that would enter would be limited to an amount that could be intercepted by the floor drains. Thus, there will be no ponding in safety-related buildings at grade level elevation of 594.0 ft MSL. Water intercepted by the floor drains would be routed to several sumps and a tank located at a lower level in the auxiliary building. Conservatively assuming that the sumps and tank are not pumped out, there would be some ponding in safety-related areas. However, as discussed in Section 3.4.1 of this report, the ponded water would not affect the safety of the plant.

The staff agrees that because there is a concrete barrier between the turbine building and safety-related areas, any water that enters the turbine building will not affect these safety-related areas. Thus, the staff concludes that the Catawba station meets the requirements of GDC-2 with respect to flooding by intense local precipitation and Confirmatory Issue 1 is now resolved.

2.4.4 Cooling Water Supply

2.4.4.2 Emergency Cooling Water Supply

In SSER 1 the staff concluded that the standby nuclear service water (SNSW) pond would not transfer heat to the atmosphere as efficiently as had been predicted by the applicant so the maximum temperature would be higher than 95°F. The staff's analysis had predicted a maximum temperature of 98.4°F. By letter dated October 13, 1983, the applicant committed to requalify all affected safety-related equipment at a temperature of at least 98.4°F. By letter dated March 13, 1984, the applicant stated that affected equipment had been requalified at a temperature of 100°F. On this basis, the staff concludes that the SNSW pond meets the suggested criteria of RG 1.27, "Ultimate Heat Sinks for Nuclear Power Plants," and its hydrologic and thermal performance meet the requirements of GDC 44. In Section 9 of this report, the staff addresses the requalification of the affected equipment and finds it acceptable. Thus, Outstanding Issue 2 is resolved.

2.5 Geology and Seismology

In 1981 the staff requested technical assistance from the Los Alamos Scientific Laboratories (LASL) to review the geology of the Catawba nuclear site and the potential for reservoir-induced seismicity (RIS) beneath Lake Wyle. The staff has received the LASL final report, which was transmitted by letter from H. N. Planner and C. A. Newton (LASL) to R. E. Jackson (NRC) November 17, 1983. Although critical of the applicant's compilation of geologic structural data for regions around the site and their lack of an interpretation of available in-situ stress measurements in relation to structural orientations, LASL concluded that the site was geologically acceptable and meets the requirements established by the NRC. LASL further concluded that the maximum RIS potential falls below the design levels for Catawba. Therefore, the LASL report supports the staff conclusions presented in Sections 2.5.1, 2.5.2, and 2.5.3 of the Safety Evaluation Report.

3 DESIGN CRITERIA - STRUCTURE, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.4 Flood Level (Flood) Design

3.4.1 Water Level (Flood) Design

In the SER, the staff stated that safety-related equipment was protected from external flooding. Subsequently, the PMP level was changed. By letter dated February 1, 1984, the applicant stated that no safety-related equipment will be affected by the resulting water levels from the PMP event, which is discussed in Section 2.4.3.2 of this report. The applicant also stated that the plant can be safely shut down by established, normal shutdown procedures. The staff has reviewed the applicant's submittal and finds it acceptable.

3.6 Protection Against Dynamic Effects Associated With Postulated Rupture of Piping

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

Introduction

As presented in Standard Review Plan (SRP) Section 3.6.2, the staff Branch Technical Position (BTP) MEB 3-1 on pipe break postulation acknowledged that pipe rupture is a rare event that may only occur under unanticipated conditions such as those that might be caused by possible design, construction, or operation errors, unanticipated loads, or unanticipated corrosive environments. The BTP MEB 3-1 pipe break criteria were intended to utilize a technically practical approach to ensure that an adequate level of protection had been provided to satisfy the requirements of 10 CFR 50, Appendix A, General Design Criterion (GDC) 4. Specific guidelines were developed in BTP MEB 3-1 to define explicitly how the requirements of GDC 4 were to be implemented. The SRP guidelines in BTP MEB 3-1 were not intended to be absolute requirements but rather represent viable approaches considered to be acceptable by the staff.

The SRP provides a well-defined basis for performing safety reviews of light water reactors (LWRs). The uniform implementation of design guidelines in BTP MEB 3-1 ensures that a consistent level of safety will be maintained during the licensing process. Alternative criteria and deviations from the SRP are acceptable provided an equivalent level of safety can be demonstrated. Acceptable reasons for deviations from SRP guidelines include changes in emphasis of specific guidelines as a result of new developments from operating experience or plant-unique design features not considered when the SRP guidelines were developed.

The SRP presents the most definitive basis available for specifying NRC's design criteria and design guidelines for an acceptable level of safety for LWR facility reviews. The SRP guidelines resulted from many years of experience gained by the staff in establishing and using regulatory requirements in the safety evaluation of nuclear facilities. The SRP is part of a continuing regulatory standards development activity that not only documents current methods of review, but also provides a basis for an orderly modification of the review process when the need arises to clarify the content, correct any errors, or modify the guidelines as a result of technical advancements or an accumulation of operating experience. Proposals to modify the guidelines in the SRP are considered for its impact on matters of major safety significance.

The staff has recently received a request from the applicant for the Catawba Nuclear Station Unit 2 to consider an alternate approach to the existing guidelines in SRP Section 3.6.2 (BTP MEB 3-1), regarding the postulation of intermediate pipe breaks. The applicant proposes to eliminate from design considerations those breaks generally referred to as "arbitrary intermediate breaks." Such breaks are defined as those break locations that, based on piping stress analysis results, are below the stress and fatigue limits specified in BTP MEB 3-1 but are selected to provide a minimum of two breaks between the terminal ends of a piping system. The staff and the applicant agreed during recent discussions that the elimination of the arbitrary intermediate breaks offers considerable cost and radiation exposure benefits resulting from the elimination of the structures associated with the protection against the effects of pipe rupture.

In the early 1970s when the pipe break criteria in BTP MEB 3-1 were first drafted, the advantages of maintaining low stress and usage factor limits were clearly recognized, but it was also believed that equipment in close proximity to the piping throughout its run might not be adequately designed for the environmental consequences of a postulated pipe break if the break postulation proceeded on a purely mechanistic basis using only high-stress and terminal-end breaks. As the pipe break criteria were implemented by the industry, the impact of the pipe break criteria became apparent on plant reliability and costs as well as on plant safety. Although the overall criteria in BTP MEB 3-1 have resulted in a viable method that ensures that adequate protection has been provided to satisfy the requirements of GDC 4, it has become apparent that the particular criterion requiring the postulation of arbitrary intermediate pipe breaks can be overly restrictive and result in an excessive number of pipe rupture protection devices that do not provide a compensating level of safety.

At the time BTP MEB 3-1 criteria were drafted, high-energy leakage cracks were not being postulated. In Revision 1 to the SRP (July 1981), the concept of using high-energy leakage cracks to mechanistically achieve the environment desired for equipment qualification was introduced to cover areas that are below the high-stress/fatigue-limit break criteria and that would otherwise not be enveloped by a postulated break in a high energy line. The staff believes that the proposal to eliminate arbitrary intermediate breaks not only retains the essential design requirement of equipment qualification, but also improves it because all safety-related equipment is to be qualified environmentally. Furthermore, certain elements of construction that may lead to reduced reliability are being eliminated.

Some requirements that have developed over the years as part of the licensing process have resulted in additional safety margins that overlap the safety margin provided in the pipe break criteria. For example, the criteria in BTP MEB 3-1 include margins to account for the possibility of flaws that might remain undetected in construction and to account for unanticipated piping steady-state vibratory loadings not readily determined in the design process. However, inservice inspection requirements for the life of the plant to detect flaws before they become critical and staff positions on the vibration monitoring of safety-related and high-energy piping systems during preoperational testing, further reduce the potential for pipe failures occurring from these causes.

Because of the recent interest expressed by the industry to eliminate the arbitrary intermediate break criterion and, particularly, in response to the detailed submittals provided by Duke for Catawba Unit 2, the staff has reviewed the BTP MEB 3-1 pipe break criteria to determine where such changes may be made.

Applicant's Bases for the Elimination of Arbitrary Intermediate Breaks

In letters (H. B. Tucker (Duke) to H. R. Denton (NRC) November 18, 1983, and February 15, March 1 and 8, 1984) the applicant presented his views on the elimination of arbitrary intermediate breaks and the technical basis for his proposal. The letters suggest a general consensus in the nuclear industry that current knowledge and experience support the conclusion that designing for the arbitrary intermediate breaks is not justified. The reasons given for this conclusion are discussed in the following paragraphs.

(1) Operating Experience Does Not Support Need for Criteria

Extensive operating experience in over 80 operating plants in the United States and a number of similar plants overseas has not resulted in piping failures that would support the need for protective features to mitigate the dynamic effects of arbitrary intermediate breaks.

(2) Piping Stresses Well Below ASME Code Allowables

Arbitrary intermediate breaks are postulated at locations in the piping system where pipe stresses are well below ASME Code allowables. In many cases the stresses may be within a few percent of the stress levels at other points in the same system. As a result, large numbers of protective features (e.g. pipe whip restraints, jet impingement shields and deflectors) are provided for specific break locations in piping systems.

(3) Arbitrary Intermediate Break Criteria Complicates Design Process

Designing for the two arbitrary intermediate breaks is a difficult process because the location of the two highest stress points tends to change several times because of the iterative process involved in the seismic design of piping systems. Although SRP Section 3.6.2 provides criteria intended to reduce the need to relocate intermediate break locations when the high stress points shift as a result of piping reanalysis, in practice, these criteria provide little relief because the responsibility rests on the designer to justify that not postulating breaks at the relocated high stress points will not result in a reduction in safety. This requires extensive additional analyses of break/target interactions for the relocated break points and could result in design, fabrication, and installation of additional pipe whip restraints at the relocated break points and the removal of previously installed restraints at superseded break points. The early determination of exact break locations in the piping system is important to ensure that proper considerations be given to mitigate the consequences of a postulated break in an effective design process and in a manner consistent with the safety significance involved.

(4) Substantial Cost Savings

The cost benefits to be realized from the elimination of the arbitrary intermediate break locations center primarily on the elimination of the associated pipe whip restraints and other structural provisions required to mitigate the dynamic consequences of these breaks. Although a substantial reduction in capital costs for these restraints and structures can be realized in the design and construction stages of the plant, there are also significant operational benefits to be realized over the 40-year life of the plant. The cost savings for Catawba Unit 2 facility are shown in Table 3.1 of this report.

Table 3.1 Summary of benefits from the elimination of arbitrary intermediate pipe breaks on Catawba Nuclear Station Unit 2

Category	Benefit
Design, material, and erection costs associated with 96 rupture devices	$4.4 million*
Relief of congestion, improving access for operation and maintenance of Unit 2 ($240,000*)	95 man-rem reduction in radiation exposure over life
Reduction in piping heat loss at whip restraint locations	Not quantitatively assessed, insulation can be installed on piping at current locations of arbitrary break pipe whip restraints
Improvement in overall plant safety (NUREG/CR-2136)	Improvement in ISI quality, elimination of potential for restricted thermal movement

*Current (1983) dollars

(5) Improved Inservice Inspection

Access during plant operation for inservice inspection (ISI) activities can be improved by eliminating the congestion created by these pipe rupture protection devices and the supporting structural steel. In addition, access to welds can be significantly improved and the need for restraint removal during weld inspection can be reduced. The need for hold points to inspect clearances between piping and pipe whip restraints during initial heatup can be eliminated during this critical startup phase for the restraints removed.

(6) Reduction in Radiation Exposure

Repairs, maintenance, and decontamination operations could be more effective if the dynamic protection devices needed for the arbitrary intermediate breaks could be eliminated. Recovery from unusual plant conditions would be improved by reducing the congestion in the plant. A significant reduction in man-rem exposure can be realized through fewer hours spent in radiation areas.

(7) Improved Operational Efficiency

Because pipe whip restraints fit closely around the high-energy piping, the piping insulation must often be cut back in these areas to avoid interferences, thus creating convection gaps adjacent to the restraints. This creates an overall increase in heat loss to the surrounding environment and is a major contributor to the tendency for many containments to operate at temperatures near limits of the Technical Specifications. The elimination of pipe whip restraints associated with arbitrary intermediate breaks would assist in controlling the normal environmental temperatures and improve system operational efficiency.

In addition, the applicant acknowledges the staff findings (NUREG/CR-2136) that an excessive number of pipe whip restraints might result in an overall reduction in plant safety when unanticipated restraint of piping thermal expansion occurs as a result of possible construction errors.

Staff Evaluation of the Request to Consider the Elimination of Arbitrary Breaks

The technical bases for the elimination of the arbitrary intermediate break criteria as discussed above provided many arguments supporting the applicant's conclusion that the current SRP guidelines should be changed. However, it is not apparent that a unilateral position by the utility concluding an unconditional deletion of the arbitrary intermediate break criteria can be justified without a clear understanding of the safety implications that can result for the various classes of high-energy piping systems involved. In this section, the staff will discuss the bases behind the current arbitrary intermediate break criteria from an ASME Code design standpoint and put into perspective the uncertainty factors on which the need to postulate arbitrary intermediate breaks should be evaluated. The staff further evaluates the acceptability of the applicant's proposed deviation from SRP Section 3.6.2.

(1) Background

The staff position (BTP MEB 3-1) recognizes that pipe rupture is a rare event that may only occur under unanticipated conditions such as those which might be caused by possible design, construction, or operation errors, unanticipated loads, or unanticipated corrosive environments. Furthermore, the staff recognizes that on those rare occasions when piping failure does occur, the failure is expected to occur at locations of high stress and fatigue such as at terminal ends of piping systems and at local welded attachments to the piping wall. This generalization does not cover situations in which stress corrosion cracking is prevalent. Thus, the staff believes that pipe breaks should be postulated at locations where there exists a relatively higher potential for failure that will result in a practical level of protection. The preceding staff positions are not new and are stated in SRP Section 3.6.2.

The extension of the staff philosophy that a pipe break may only occur at high stress and fatigue locations to the SRP guideline--which requires that two intermediate breaks be postulated even when the piping stress is low--resulted from the need to ensure that equipment qualified for the environmental consequences of a postulated pipe break was provided over a greater portion of the high-energy piping run.

The staff now proposes to dispense with arbitrary intermediate breaks as discussed above on the condition that all equipment in the spaces traversed by the fluid system lines, for which arbitrary intermediate breaks are being eliminated, is qualified for the environmental (nondynamic) conditions that would result from a nonmechanistic break with the greatest consequences on surrounding equipment.

(2) ASME Code Class 1 Piping Systems

In accordance with BTP MEB 3-1 (paragraph B.1.c.(1)), breaks in ASME Code Class 1 piping should be postulated at the following locations in each piping and branch run:

(a) at terminal ends;

(b) at intermediate locations where the maximum stress range as calculated by Eq. (10) and either Eq. (12) or (13) of ASME Code NB-3650 exceeds 2.4 Sm;

(c) at intermediate locations where the cumulative usage factor exceeds 0.1.

(d) If two intermediate locations cannot be determined by (b) and (c) above, two highest stress locations based on Eq. (10) should be selected.

The arbitrary intermediate break criteria is stated in (d) above. It should be noted that the request for alternative criteria does not propose to deviate from the criteria in (a), (b), and (c) above.

Pipe breaks are to be postulated at terminal ends. Thus, the staff concern regarding piping failures that have occurred at terminal ends will continue to be evaluated for a postulated pipe break irrespective of the piping stresses.

Pipe breaks are to be postulated at intermediate locations where the maximum stress range as calculated by Equation (10) and either Equation (12) or (13) exceeds 2.4 Sm. The stress evaluation in Equation (10) represents a check of the primary plus secondary stress range due to ranges of pressure, moments, thermal gradients and combinations thereof. Equation (12) is intended to prevent formation of plastic hinges in the piping system caused by only moments due to thermal expansion and thermal anchor movements. Equation (13) represents a limitation for primary plus secondary membrane plus bending stress intensity excluding thermal bending and thermal expansion stresses, which is intended to ensure that the K_e factor (strain concentration factor) is conservative. The K_e factor was developed to compensate for absence of elastic shakedown when primary plus secondary stresses exceed 3 Sm.

With respect to piping stresses, the pipe break criteria were not intended to imply that breaks will occur when the piping stress exceeded 2.4 Sm (80% of the primary plus secondary stress limit). It is the staff's belief, however, that if a pipe break were to occur (in one of those rare occasions), it is more likely to occur at a piping location where there is the least margin to the ultimate tensile strength.

Similarly, from a fatigue strength standpoint, the staff believes that a pipe break is more likely to occur where the piping is expected to experience large cyclic loadings. Although the staff concurs with the industry belief that a cumulative usage factor of 0.1 is a relatively low limit, the uncertainties involved in the design considerations with respect to the actual cyclic loadings experienced by the piping tend to be greater than the uncertainties involved in the design considerations used for the evaluation of primary and secondary stresses in piping systems. The staff finds that the conservative fatigue considerations in the current SRP guidelines provide an appropriate margin of safety against uncertainties for those locations where fatigue failures are likely to occur (e.g. at local welded attachments).

In its presentation to the ACRS on June 9, 1983, and in an October 5, 1983, meeting between a group of pressurized water reactor (PWR) near-term operating license utilities and the NRC staff, the staff indicated that the elimination of arbitrary intermediate breaks was not to apply to piping systems in which stress corrosion cracking, large unanticipated dynamic loads such as steam or water hammer, or thermal fatigue in fluid mixing situations could be expected to occur. In addition, the elimination of arbitrary intermediate breaks was to have no effect on the requirement to environmentally qualify safety-related equipment. In fact, this requirement was to be clarified to ensure positive qualification requirements.

For Class 1 piping, a considerable amount of quality assurance in design, analyses, fabrication, installation, examination, testing, and documentation is provided, which ensures that the safety concerns associated with the uncertainties discussed above are significantly reduced. On the basis of its evaluation of the design considerations given to Class 1 piping, the stress and fatigue limits provided in BTP MEB 3-1 break criteria, and the relatively small degree of uncertainty in the loadings, the staff finds that the need to postulate arbitrary intermediate pipe breaks in ASME Code Class 1 piping in which large unanticipated dynamic loads, stress corrosion cracking, and thermal fatigue such as in mixing situations are not present and in which all equipment has been environmentally qualified is not compensated for by an increased level of safety. In addition, systems may actually perform more reliably for the life of the plant if the request to postulate arbitrary intermediate break criteria for ASME Code Class 1 piping is eliminated.

The staff has concluded that these requirements are present for those ASME Code Class 1 piping systems identified in the applicant's submittal letter of November 18, 1983.

(3) ASME Code Class 2 and 3 Piping Systems

In accordance with BTP MEB 3-1 (paragraph B.1.c.(2)) breaks in ASME Code Class 2 and 3 piping should be postulated at the following locations:

(a) at terminal ends

(b) at intermediate locations selected by one of the following criteria:

(i) at each pipe fitting, welded attachment, and valve

(ii) at each location where the stresses exceed 0.8 (1.2 S_h + S_A) but at not less than two separated locations chosen on the basis of highest stress.

In its proposal the applicant has not proposed changing criterion (a) above. Postulation of pipe breaks at terminal ends will not be eliminated in the proposed SRP deviation for Class 2 and 3 piping systems. Breaks are required to be postulated at terminal ends irrespective of piping stresses.

The "arbitrary intermediate break criteria" is stated in (b)(ii) above where breaks are to be postulated at intermediate locations where the stresses exceed 0.8 (1.2 S_h + S_A) but "at not less than two separated locations chosen on the basis of highest stress." The stress limit provided in the above pipe break criterion represents the stress associated with 80% of the combined primary and secondary stress limit. Thus, a break is required to be postulated where the maximum stress range as calculated by the sum of Equation (9) and (10) of NC/ND-3652 of the ASME Code, Section III, considering those loads and conditions for which A and B stress levels have been specified in the system's design specification (i.e. sustained loads, occasional loads, and thermal expansion) including an operating-basis earthquake (OBE) event, exceeds 80% of the combined primary and secondary stress limit. However, the Class 2 and 3 pipe break criteria do not have a provision for the postulation of pipe breaks based on a fatigue limit because an explicit fatigue evaluation is not required in the ASME Code for these classes of construction because of favorable service experience and lower levels of operating cyclic stresses. For those Class 2 and 3 piping systems that experience a large number of stress cycles (e.g. main steam and feedwater systems), the ASME Code has provisions to address these types of loads. The rules governing considerations for welded attachments in ASME Class 2 and 3 piping that do preclude fatigue failure are partially given in paragraph NC/ND-3645 of the ASME Code. The Code states:

> External and internal attachments to piping shall be designed so as not to cause flattening of the pipe, excessive localized bending stresses, or harmful thermal gradients in the pipe wall. It is important that such attachments be designed to minimize stress concentrations in applications where the number of stress cycles, due either to pressure or thermal effect, is relatively large for the expected life of the equipment.

Code rules governing the fatigue effects associated with general bending stresses caused by thermal expansion are addressed in NC/ND-3611.2(e) and are generally incorporated into the piping stress analyses in the form of an allowable stress reduction factor.

Thus it can be concluded that when the piping designers have appropriately considered the fatigue effects for Class 2 and 3 piping systems in accordance with NC/ND-3645, the likelihood of a fatigue failure in Class 2 and 3 piping caused by unanticipated cyclic loadings can be significantly reduced.

On the basis of the staff's evaluation of the design considerations given to Class 2 and 3 piping, the stress limits provided in the SRP break criterion, and the degree of uncertainty in unanticipated loadings, the staff finds that dispensing with arbitrary intermediate pipe breaks is justified for Class 2 and 3 piping in which stress corrosion cracking, large unanticipated dynamic loads, or thermal fatigue in fluid mixing situations are not expected to occur provided (a) the piping designers have appropriately considered the effects of local welded attachments per NC/ND-3645 and (b) all safety-related equipment in the vicinity of Class 2 and 3 piping systems have been environmentally qualified for the nondynamic effects of a nonmechanistic pipe break with the greatest consequences on the equipment. The staff has concluded that the above described requirements are present for those ASME Code Class 2 and 3 piping systems identified in the applicant's letter dated November 18, 1983.

(4) Piping Systems Not Included in Proposal

For those piping systems, or portions thereof, that are not included in the applicant's submittal (letter of November 18, 1983), the staff requires that the existing guidelines in SRP Section 3.6.2 be met. However, should other piping lines that are not specifically identified in the applicant's submittal subsequently qualify for the conditions described above, the implementation of the proposed elimination of the arbitrary intermediate break criteria may be used, provided those additional piping lines are appropriately identified to the staff.

(5) Conclusion

In conclusion, the applicant has proposed a deviation from the current guidelines of the SRP by requesting relief from postulating arbitrary intermediate pipe breaks in high-energy piping systems. The staff has evaluated the technical bases for the proposed deviation with respect to satisfying the requirements of GDC 4. Furthermore, the staff has considered the potential problems identified in NUREG/CR-2136 that could impact overall plant reliability when excessive pipe whip restraints are installed. On the basis of its review, the staff finds that when those piping system conditions as stated above are met, there is a sufficient basis for concluding that an adequate level of safety exists to accept the proposed deviation. Thus, based on the piping systems having satisfied the above conditions, the staff concludes that the pipe rupture postulation and the associated effects are adequately considered in the design of Catawba Unit 2 and, thus, the deviation from the SRP is acceptable.

3.7 Seismic Design

3.7.3 Seismic Subsystem Analysis

As indicated in SSER 1, the applicant has performed the soil-structure interaction (SSI) analysis of the above-ground storage tank for Unit 2 using "lumped-parameter" (half-space) approach. It was further discussed in SSER 1 that the current staff acceptance criteria require that the SSI analysis of seismic Category I structures should include both the half-space and finite-boundary approaches. By a letter dated April 15, 1983, the applicant provided the following information to indicate why additional SSI analysis based on the finite-boundary approach is not required for this tank.

(1) The partially weathered rock supporting the above-ground storage tank (Unit 2) is very rigid causing the tank to behave essentially as if the base were fixed. (Comparison with the identical tank dynamic model run as fixed base indicates a first mode frequency difference of less than 5%.)

(2) Because the tanks are supported above ground, embedment effects are negligible.

(3) Soil column analysis (program SHAKE) of the actual site conditions indicates very little variation in acceleration with depth (FSAR Figure 2.5.2-8B) in the partially weathered rock supporting stratum.

(4) The nearest structure of consequence with respect to interaction is approximately at a distance of four times the tank foundation radius. The depth of the partially weathered rock supporting stratum is slightly greater than the radius of the tank foundation.

On the basis of the review of the above information, primarily because of reasons identified in (1) and (2), the staff concludes that performing an additional SSI analysis using the finite-boundary approach will not have any impact on the design of the Unit 2 above-ground storage tank and, therefore, the intent of the staff's acceptance criteria on the SSI analysis has been met. Confirmatory Issue 6, regarding the SSI analysis of the above-ground storage tank for Unit 2, is now considered resolved.

3.9 Mechanical Systems and Components

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

3.9.3.2 Design and Installation of Pressure Relief Devices

As required by NUREG-0737, "Clarification of TMI Action Plan Requirements," Item II.D.1, all pressurized-water-reactor (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 loading that would demonstrate the operability of these valves and the associated piping.

On October 26, 1983, and February 3, 1983, Duke Power Company responded to this requirement with a submittal that contains information from the EPRI valve test program results that applies to Catawba Units 1 and 2. The submittal also states that the safety and relief valve discharge piping and supports have been verified to ensure functionability.

The staff has not completed a detailed review of the applicant's submittals; however, on the basis of its 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 submittal notes that Catawba Units 1 and 2 use safety valves, PORVs, and PORV block valves of essentially the same size and model that performed satisfactorily for test sequences considered representative or that bound conditions that Catawba Units 1 and 2 valves could be exposed to.

On the basis of its preliminary review, the staff has concluded that the applicant's general approach to responding to this TMI item is acceptable and provides adequate assurance that Catawba Units 1 and 2 reactor coolant system overpressure protection systems can adequately perform their intended functions for the period during which the staff completes its detailed review. 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 ensure that all intended design margins are present, the staff will require that the applicant make appropriate modifications.

3.9.6 Inservice Testing of Pumps and Valves

In the SER, the staff stated that the applicant had not yet submitted a program for inservice testing of pumps and valves and, therefore, the staff had not completed its review. The applicant has submitted by letter dated March 9, 1983, an inservice testing program for pumps and valves.

The applicant has stated that the preservice and inservice testing program 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 requested relief from these Code requirements pursuant to 10 CFR 50.55a(g)(5)(iii) for certain pump and valve tests.

At this time, the staff has not completed its detailed review of the applicant's submittal. However, the staff has evaluated the applicant's request for relief. On the basis of its review, the staff 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 these 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 staff believes that the relief that the applicant has requested from the pump and valve testing requirements of the 1980 Edition of ASME Section XI through the Winter 1980 Addenda should be granted for a period of no longer than 2 years from the date an operating license is issued or until the staff's detailed review has been completed, whichever comes first. The staff, therefore, will condition the license to reflect the above discussion. If completion of the staff's review results in additional testing requirements, the staff will require that the applicant comply with them.

3.10 Seismic and Dynamic Qualification of Safety-Related 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 selected equipment items to develop the basis for staff judgment on the completeness and adequacy of the implementation of the entire seismic and dynamic qualification program. The Seismic Qualification Review Team (SQRT) consists of staff engineers and engineers from the Brookhaven National Laboratory (BNL). The SQRT has reviewed the equipment dynamic qualification information in FSAR Sections 3.9.2 and 3.10 and made a plant site visit March 13 through March 16, 1984, to determine the extent to which the qualification of equipment as installed at Catawba Unit 1 meets the current licensing criteria described in RGs 1.100 and 1.92, SRP Section 3.10, and Institute of Electrical and Electronics Engineers (IEEE) Standard 344-1975. Conformance with these criteria is required to satisfy the applicable portions of GDC 1, 2, 4, 14, and 30 of Appendix A to 10 CFR 50, Appendix B to 10 CFR 50, and Appendix A to 10 CFR 100. A representative sample of safety-related electrical and mechanical equipment, as well as instrumentation, included in the nuclear steam supply systems (NSSSs) and the balance-of-plant (BOP) systems, was selected for audit at the Catawba Unit 1 plant site. The plant site visit consisted of field observations of the actual, final equipment configuration and its installation. This was immediately followed by the review at the applicant's engineering office in Charlotte, North Carolina, of the corresponding test and/or analysis documents, which the applicant maintains in his central files. Observation of the field installation of the equipment is required to verify and validate equipment modeling used in the qualification program.

The details of the audit and the staff's preliminary list of concerns expressed for qualification of both the NSSS and the BOP equipment have been separately documented by the SQRT as a trip report, transmitted to the applicant by letter dated June 13, 1984. These concerns were communicated to the applicant during the audit for his appropriate action. The applicant subsequently responded to these concerns by providing evidence of additional qualification and/or justification of existing qualification in a letter dated April 18, 1984. On the basis of the audit and review of the above-referenced applicant's response, several plant-generic and -specific concerns relating to the seismic and dynamic qualification of equipment remain to be confirmed or resolved by the applicant to establish acceptability of the program. The staff's findings are summarized in Sections 3.10.1.1 and 3.10.1.2 of this report, and a summary of the staff's evaluation of the applicant's program is provided in Section 3.10.1.3.

3.10.1.1 Generic Issues

Confirmation of Acceleration Values for Pipe-Mounted Equipment

In the referenced response (April 18, 1984), the applicant stated that his QA procedures require the as-built piping analysis accelerations to be within the specified qualification limits. This response is inadequate to resolve the issue. The applicant should confirm that the analysis has indeed been performed and the resulting accelerations are acceptable.

Proper Modeling of Flexible Pipe-Mounted Equipment

In certain cases, for example, the upper head injection (UHI) valve qualification reports indicate multiple natural frequencies below 33 Hz and the feedwater isolation valve exhibits one flexible mode. Thus for flexible pipe mounted equipment, the applicant should confirm that the as-built piping system was modeled with the flexible equipment mass and dynamically analyzed, and the resulting stress and acceleration values do not exceed the respective allowable and qualification levels.

3.10.1.2 Equipment Specific Issues

Solid-State Protection System (Westinghouse Report WCAP-7817, Revision 0).

During the audit, Westinghouse stated that they produce one, and only one, type of solid-state protection system (SSPS), which was supplied to Catawba and the same type was tested in the laboratory. This was not confirmed in the subsequent response. A written confirmatory statement from Westinghouse is necessary to demonstrate an auditable link between the equipment installed in the field and the specimen tested. Otherwise, establishment of a dynamic similarity between the two will be required.

During the audit, test resonance frequencies and justification for acceptability of the qualification for the frequency range, 25-33 Hz, was not presented by the applicant. In the referenced response, Westinghouse mentioned the existence of some test data in the missing frequency range. Identification of the pertinent test report by the applicant and a satisfactory evaluation by SQRT is necessary to close out this item. The applicant should also document the resonance frequencies because the testing was single-frequency type.

In response to the SQRT concern that complete test mounting details are not included in the qualification report, the applicant responded by stating that this information is available in SQRT forms. This response is not acceptable. Test mounting details, therefore, should be completely defined and made part of the qualification package.

During the audit, discrepancies were observed between test mounting and field mounting configuration. Nonmetallic insulating washer, used for field installation of the cabinet, introduces additional flexibility in the equipment and also a gap with the mounting surface; consequently it deviates from the test mounting. It is necessary that the applicant modify field mounting to match test mounting, or justify the existing field mounting by additional tests.

Centrifugal Charging Safety Injection Pump/Motor (Pacific Report K-318-1, Revision 5)

During the audit, the SQRT expressed concern regarding effects of operating bearing pressure in the analysis. In the referenced response, Westinghouse mentioned that an additional analysis has been performed by them after the audit to address this issue. This additional analysis should be made available for the SQRT review.

In regard to the torsional natural frequency and whether a resonance condition exists between the critical speed and the operating speed, Westinghouse simply made reference to torsional frequency calculations not presented during the audit. It is necessary that these calculations be reviewed by SQRT to close out this item.

RHR Pump/Motor (McDonald Report ME-174)

The SQRT has questioned the stress calculations made for the particular area at the nozzle-to-casing interface (e.g., elements 90 and 92 in the finite element analysis contained in the report). Per Westinghouse's response, at least one node point of element 92 is overstressed, and Westinghouse utilized a stress-averaging method to reduce the resulting stress. Because element 92 is on the "load path," this particular element should be separately investigated, and further justification is necessary to demonstrate adequacy of the qualification of the pump.

Because operating hydrodynamic bearing pressure was not included in the analysis audited, it is necessary that a new analysis be conducted and the result reviewed by the SQRT.

Finally, regarding the same comment on torsional natural frequency as for the above mentioned centrifugal charging safety injection pump/motor, it is necessary that the Westinghouse calculations be reviewed by the SQRT so that this issue can be closed out.

Engineered Safeguards Test Cabinet (Westinghouse Report WCAP-7817, Supplement 7)

The same comment regarding the discrepancies between test mounting and field mounting configuration as in the case of the solid-state protection system applies. It is necessary that the applicant modify field mounting to match test mounting, or justify the existing field mounting by additional tests.

4160-Volt Essential Switchgear (Gould Report 33-50465 Addendum II, September, 1981)

During the audit, SQRT observed that the summary report prepared by Gould claims no electrical malfunction during the test. However, page 1 of the Wyle Test Report (the only page available) indicated chatter on certain relays and minor problems with the circuit breakers. For a complete description of the malfunction, the report prepared by the Wyle Laboratory should be made available for SQRT review and acceptance.

For the above mentioned anomalies, the applicant has subsequently provided a justification for acceptance. Acceptability of the justification will be determined after staff review of the above Wyle Test Report.

During the audit, SQRT observed that the qualification of a 4-cubicle test specimen was being extended to that of the 18-cubicle switchgear. The applicant was then requested to address the torsional mode resulting from multiple units and ensure that any additional unit does not use a common enclosure wall.

In response to this issue, the applicant/vendor simply made reference to a new test report not presented during the audit. It is necessary that this report be made available for SQRT review.

It was also found, during the audit, that qualification documentation for power resistors and certain relays was not complete (ITE Report R-09161-CI, dated May 27, 1975). To close out this issue, it is necessary that a complete description of the test procedures and test results be presented in an auditable manner and further reviewed by the SQRT.

Main Control Boards (Duke Specification CNS-1393.00-00-0002, Revision 3)

Qualification of the main control board utilized a combination of test and analysis method. In the finite element method of analysis, however, the device mounting locations on the enclosure panel were not properly included in the panel model. As a result, stresses and required response spectrum at these locations may not have been adequately predicted by the existing analysis. Clarification of its adequacy should, therefore, be demonstrated by the applicant. In addition, while comparison of the mode shapes between the in-situ test results and the analysis, including the corresponding parametric studies, were performed by the applicant, they were not properly documented.

In the referenced response, the applicant stated that a revision to the existing qualification documentation addressing the above SQRT concerns was being made. Evidence of completion of such revision will enable SQRT to close out the issues.

The SQRT also requested the applicant, during the audit, to perform an as-built weld survey for the mounting channel and to demonstrate that the welding is in compliance with the support conditions assumed in the analysis.

In the referenced response, the applicant stated that the weld survey was in progress. The results, when they become available, should be subject to further SQRT review.

Pressurizer PORV (Control Component Report 18789-1 and 2)

Information regarding operability of the actuator and its electrical accessories under dynamic seismic load conditions was not presented for SQRT review during the audit. Demonstration of the operability by the applicant is necessary to close out this issue.

18-Inch Feedwater Isolation Valve/Actuator (Borg-Warner Report NSR-74040, dated August 25, 1978)

The SQRT has questioned the effect of waterhammer load on the valve design. In response, the applicant/vendor stated that the waterhammer load is not appreciable. To close out this issue, it is necessary that pertinent load calculations be reviewed by the SQRT to determine that it is indeed not appreciable.

Containment Return Air Isolation Damper Operators (Wyle Report 43979-1, Revision A)

Since the operator was qualified with 1/3-rated torque, the SQRT has requested the applicant to demonstrate that this torque is adequate to operate the damper. The SQRT has also requested demonstration of structural adequacy of the mounting bracket, as well as documentation of the test mounting bolts and their comparison with the field installation bolts.

In the referenced response, the applicant stated that they were in the process of obtaining additional qualification to address these issues. The additional information should be subjected to further SQRT review when available.

Motor Operators (ITT Report 721.77.095, dated March 14, 1977)

The SQRT revealed that the motor operator qualification requires the operator to be in the upright position, although the operator inspected during the audit was mounted horizontal. To resolve this discrepancy, the applicant in the referenced response, simply made reference to a new report they have recently obtained to qualify the horizontal installation. It is necessary that this report be made available for SQRT review and acceptance.

3.10.1.3 Summary

On the basis of its review of the qualification documents, site inspection and interpretation provided by the applicant during the audit, and the applicant's April 18, 1984, submittal, the staff concludes that the applicant's equipment seismic and dynamic qualification program is well defined and substantially implemented. The exceptions are these items which remain to be either clarified or resolved, as indicated in Section 3.10.1.1 for generic items and Section 3.10.1.2 for equipment-specific items. In view of the nature of the open items and the preliminary responses provided by the applicant, it is the judgment of the staff that the plant can be permitted to go beyond initial criticality if the generic items are completely resolved and that all the safety-related equipment of the entire plant have gone through the required seismic and dynamic qualification. In addition, all the above equipment-specific items will have to be completely resolved before the plant can exceed 5% power operation.

3.10.2 Operability Qualification of Pumps and Valves

To ensure that the applicant has provided an adequate program for qualifying safety-related pumps and valves to operate under normal and accident conditions, the staff performed a two-step review. The first step was a review of FSAR Section 3.9.3.2 for the description of the applicant's pump and valve operability assurance program. This information was compared with SRP Section 3.10. The information provided in the FSAR, however, is general in nature and not sufficient by itself to provide confidence in the adequacy of the applicant'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, conducted an onsite audit of a small representative sample of safety-related pumps and valves and supporting documentation.

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

The two-step review was performed to determine the extent to which the qualification of equipment, as installed, meets the current licensing criteria in SRP Section 3.10. Conformance with these criteria provides an acceptable way of meeting the applicable portions of GDC 1, 2, 4, 14, and 30 as well as Appendix B to 10 CFR 50.

The onsite audit for Catawba Unit 1 was performed March 13-16, 1984. A walk-down was conducted to observe the as-built configuration of the selected equipment and to check for areas of deficient qualification. Whenever possible, the plant engineers described the features and operating procedures unique to the equipment. A representative sample of three pumps and eight valves was chosen for the review. One of the valves was a "surprise selection" that was chosen to evaluate document retrieval and the completeness of the applicant's central files. The sample included both NSSS and BOP equipment. The qualification documents were examined at the Duke Power Co., Charlotte, North Carolina, office, where the applicant maintains his central files. Document packages containing addenda to generic specifications, such as specific information on valves and pumps and test data, were kept at the Catawba site. These data were readily available to the staff upon request.

During the PVORT review, a number of concerns were raised. All of the major specific concerns were satisfactorily resolved by the applicant during the audit who either supplied additional information or demonstrated that the appropriate commitments are already addressed by administrative controls. Accordingly, no additional Catawba (PVORT) onsite followup visits are anticipated by the staff for this audit. The following discussion indicates the manner by which the applicant addressed generic and specific issues at the Catawba plants.

In preparation for the PVORT audit, the staff reviewed Catawba FSAR Section 3.9.3.2 and the master list of seismic Category I equipment. The applicant provided sufficient information in these documents to allow the staff to conduct the onsite audit. Discussions with plant personnel during the audit further enhanced the staff's understanding of the equipment's functions and qualification program.

The utility staff briefly described the maintenance and quality assurance preoperational testing program. The execution of this program satisfactorily addressed the concern of the operational status of plant equipment. Many preoperational tests have already been completed, and preoperational testing was in progress during this audit.

The staff noted that for some components, environmental qualification reports were still being prepared and organizational maintenance instruction manuals were not completed. The applicant, however, demonstrated overall accountability by committing appropriate personnel to resolve these concerns.

The staff observed the occasional inaccessibility or lack of clarity concerning the serial numbers of an installed component. This was due in large measure to the insulation put over a valve body, thereby covering its identification tag. The staff noted, however, that the component documentation did identify the installed component's serial number, and a procedure was in place to update component identification as required.

One generic concern involved the in-service testing requirements for supporting components, which are themselves safety related, to the front-line safety-related components. In the particular case, pit sump pump 1A (which is part of the liquid radwaste system and is designed to preclude flooding of the auxiliary feedwater pump) for motor-driven auxiliary feedwater pump 1A has no in-service testing requirements. The applicant's position is that because the pit sump pump is not required to operate to mitigate the consequences of an accident or to perform a specific function in shutting down a reactor, no mandatory in-service tests are required. The redundancy of the two motor-driven pumps and one turbine auxiliary feedwater pump is another factor in favor of the applicant's position. The staff referred to ASME Code, Section XI, 1980, IWP-1000, for in-service testing of nuclear power plant components, and noted that Class 1, 2, and 3 pumps that are supplied with emergency power solely for operating convenience may be excluded from in-service testing requirements. The applicant indicated that the manufacturer's recommendations, along with his experience with sump pumps at other facilities (both nuclear and fossil) will be used in implementing a maintenance and testing program. The applicant has demonstrated overall accountability for this concern.

The applicant's specifications considered load combinations for equipment design in the following way. A seismic design guide was provided in either the original purchase specification or in a subsequent addendum. The guide indicated that the stresses resulting from normal design, deadweight, and seismic loads are to be combined and compared with the allowable values. The normal design pressure (and temperature) was obtained from the valve list or directly from the pump design specification in the case of pumps. The applicant specified the expected seismic and nozzle loads in the purchase specification, and the manufacturer provided the deadweight of the component.

Another generic concern raised was the operation of both pumps and valves at reduced grid system voltages. Although the applicant's motor specifications did not specifically identify any such requirement, the specifications did refer to the National Electrical Manufacturers Association NEMA-MG-1 specification, "Motors and Generators," which requires ac motors to operate successfully under running conditions at rated load with a voltage variation of plus or minus 10% of rated voltage. Therefore, the staff finds that the applicant has satisfactorily addressed this concern.

The utility staff described the manufacturing/quality control program of tracking the plant's operational state. The execution of this program satisfactorily addressed the concern of the operational status of plant equipment. Additionally, a brief description of a recently initiated effort, whereby engineers knowledgeable about pumps and valves reevaluated their component-to-operator torque requirements, was presented. The torques provided were reassessed to ensure an adequate and safe match of motor/air drivers with their respective pumps/valves. The staff was impressed with this applicant-initiated effort with regard to the operational status of the plant equipment.

The equipment qualification personnel for Catawba are dealing with the equipment qualification issue in a very positive manner. The staff has reached this conclusion because the applicant has, with a high percentage of completeness (1) provided adequate documentation to demonstrate qualification of safety-related pumps and valves, (2) established administrative programs to determine, monitor, and maintain equipment operability for the lifetime of the plant, (3) demonstrated an adequate central file system by the timely retrieval of information requested by the staff during the audit, (4) corresponded with equipment suppliers to discuss and evaluate details of construction, test procedures, and plant operation and (5) demonstrated overall accountability by committing the appropriate personnel to implement these programs.

Generic Findings

There remains a small percentage of component accessories, such as solenoid valves, whose qualification programs at the time of the PVORT audit were not complete or approved by the applicant. The staff requests that the applicant submit for staff approval documentary confirmation that will verify that all safety-related equipment has been qualified and that as-built conditions and loads (e.g., nozzle loads) agree with those loads specified in the design and purchase specifications.

Specific Concerns

A number of minor concerns, noted during the Catawba walkdown, were satisfactorily resolved during the audit. Many of these issues were satisfactorily addressed by administrative controls already in effect. The PVORT made a check of the applicant's documentation system by requesting on short notice and reviewing in detail the appropriate specifications, certificates of conformance, test reports, and related document controls. The following examples illustrate the manner by which the applicant satisfactorily addressed specific concerns at the Catawba plant.

(1) Auxiliary Feedwater Pump 1A (Part Number CN1MCAPU001) and Its Electric Motor Driver (S.O.79F55430)

A PVORT concern about margins of safety for in-service maintenance checks of vibration levels, flow rates, clearances, and so forth was addressed. The applicant's in-service test program for pumps specified that an alert range and a required action range be established for these concerns in accordance with the suggested tolerances from the normal range in ASME Code, Section XI. An analysis was performed to confirm shaft clearances and tolerances for a combined seismic and dynamic load condition, including startup torque.

A concern about low-voltage motor operation was resolved when data were produced showing motor operation at 80% normal voltage, with no motor stall.

Therefore, the applicant has satisfactorily completed the operability qualification requirements for this pump.

(2) Auxiliary Feedwater System (Discharge) 4-in. Swing Check Valve (Part Number 1CA037)

The staff was concerned about the valve disc impact loads on the valve's internal parts, i.e., valve pin, seat, disc stud, nut, and so forth. It was shown that the valve manufacturer, Borg-Warner, had initiated an investigation concerning this subject. The results of this investigation led to a valve modification whereby a seal weld was added around the stud/disc interface and the stud/clapper nut interface. The applicant was asked to retrieve a Certificate of Conformance and a data sheet showing hydrostatic shell and seat leakage results. This request was quickly fulfilled with documentation from the Catawba site document package files. Therefore, the applicant has satisfactorily completed the operability qualification requirements for this valve.

(3) Motor-Driven Auxiliary Feedwater Pump Pit Sump Pump 1A (S/N NSP001288) and Motor (S/N 1YF-882457)

The vertical pump was not fully assembled when it was observed during the inspection at the plant site. The pump itself was not visible because it is mounted to the underside of a steel plate covering the sump, and the motor was not in place. Thus, it was not possible to check serial numbers. The applicant stated that, during the initial run, the motor experienced vibration problems and was, therefore, returned to the manufacturer for either repair or replacement. The component will be retested, and its acceptability will be documented in conformance with the project quality control procedures. The applicant also indicated that the problem was not generic in nature but an individual case. As explained above, a question arose about the in-service testing to be performed. The pump's function is to preclude flooding of the auxiliary feedwater pump so that even during operation of the latter, the sump pump is on standby. The applicant's experience with the sump pump and the pump manufacturer's recommendations are being applied in establishing a satisfactory test and maintenance program.

The frequency analysis indicated that a seismic support is necessary for the first critical frequency to exceed 33 Hz. The proper input stresses (seismic, nozzle, normal design, and deadweight loads) were considered in the analysis. The analysis considered the identical size and type of pump and motor.

The hydrostatic test results showing satisfactory completion were provided on demand, as was an acceptable pump performance curve. There were no deviations from the specifications. The pump uses filtered discharge water for bearing lubrication, and the thrust bearings are self-contained by packing with grease. Aging of components will be addressed in the applicant's ongoing environmental qualification program.

Therefore, the applicant has satisfied the operability qualification requirements for this pump.

(4) Reactor Coolant System Pressurizer Power Air Operated Relief Valve (Part Number 1NC32B)

The staff noted that this valve required substantial redesign and testing because of problems uncovered at the McGuire nuclear facility. The staff was concerned about this requalification effort and asked to see data sheets associated with this retesting. These sheets were retrieved within hours from the Catawba files' respective data package for staff review. The testing requirements were developed by Electric Power Research Institute on the basis of functional and operational testing done at the Duke Power Company's Marshall plant (February 5-6, 1980, and July-August, 1980, respectively) and the two-phase testing performed at Wylie Laboratories (June 17-July 2, 1981). Verbal confirmation of the certificates of conformance to specification requirements was made. The staff noted that for two solenoid valves (Valcor Model V70900-301), which are safety-related functional accessories, the qualification package was not yet approved by the applicant. The PVORT was assured that this would be signed off before fuel loading. Another specific concern was the valve packages' 19-Hz fundamental frequency. The applicant's representative explained that a detailed modeling analysis was performed that considered the valves' 19-Hz natural frequency. This analysis determined that the valve is acceptable regarding operability in its current location.

Subject to confirmation that all safety-related component qualification reports will be completed and approved, this concern is satisfactorily resolved.

(5) Residual Heat Removal Pump 1A (S/N 077645) and Motor (S/N 76F60009-1S-78)

The applicant stated that the qualified life of the vertically installed pump assembly is 40 years but that of the motor is only 5 years. The staff questioned whether this meant that the motor would be changed every 4 years (plus allowance for 1 year of postaccident operation). The applicant, represented by Westinghouse, replied that the 5-year figure was based on a Westinghouse report entitled "Environmental Qualification of Class 1E Motors for Nuclear Out of Containment Use," March 1976, which as its name implies is oriented toward environmental qualification as opposed to pump and valve operability. Because the pump will be subjected to periodic in-service testing with measurement of appropriate parameters, such as motor insulation resistance, the staff decided that this concern was adequately addressed by the applicant.

Another issue raised by the staff was to what extent pump performance would be degraded if system grid voltage dropped to 10% below normal. The applicant stated that if this situation persisted for a period of 10 min, the emergency diesel-generators would automatically begin operation. It was also determined that the motor was designed in accordance with NEMA MG-1, which requires that the motor deliver rated power at 10% reduced voltage. This subject has been discussed in the generic concerns.

With respect to aging, the applicant stated that the shaft seals contain asbestos, which has been shown to be insusceptible to radiation. The motor's qualified life of 5 years is primarily limited by the thermoelastic epoxy that is used for insulation.

Therefore, the applicant has satisfactorily completed the operability qualification requirements for this component.

(6) 12-in. Residual Heat Removal Isolation Gate Valve (Tag No. IND-001B) and Electric Actuator (S/N B3496/B3)

For this valve, the required torque was given as 1,540 ft-lb, while the design torque, at which the torque switch is set, is 1,550 ft-lb. The applicant explained that the apparently low torque margin is misleading because that setting pertains to opening the normally closed valve at the system design pressure of 2,485 psig. In actuality, the valve would (and should) only be opened during cooldown to cold shutdown conditions beginning at a pressure of 400 psig, at which point the required torque is much lower.

At the PVORT staff's request, the applicant produced a complete test report that included backseat leakage, hydrostatic shell and stuffing box leakage, hydrostatic seat leakage, closure time, and so forth.

Because the valve may be subjected to full-flow conditions for as long as 1 year, erosion of the valve seats could be of concern under some circumstances. Test results provided by the applicant show satisfactory performance at velocities up to 15 ft/sec. Another concern was that operability qualification should be demonstrated for the following conditions:

(a) The valve opens and remains open during an extended cold shutdown

(b) The valve remains closed during normal plant operation.

This operability has been demonstrated.

Therefore, the applicant has satisfactorily completed the operability qualification requirements for this valve.

(7) Ice Condenser Refrigeration System (Containment Isolation) 4-in. Gate Valve (Part Number 1NF234A) and Its Model A-53B Air Actuator

The staff noted that the valve's serial number was not visible. The applicant was asked to keep updated serial numbers visible. The staff was concerned about a substitute valve wedge and body used in the qualification program unit. The applicant explained that the manufacturer had replaced these parts with identical ones with respect to dimensions, materials, tolerances, and finishes. The replacement parts had not gone through an expensive nondestructive test program, but they were similar to ones that had. Although the staff did not particularly agree with this approach, it found no reason to reject the qualification testing.

Another concern was that testing for this valve was done at ambient conditions, although the valves' glycol/water operation is at -5° to 2°F. The applicant furnished data that indicated that the effect of the nil ductility transition temperature on wedge/seat brittleness was addressed, as were the effects of low temperature on internal leakage. A consultant investigated these concerns and found that there was no problem associated with the transitional temperature. For this particular valve, preoperational testing will include flow interruption stroke time tests.

The staff also noted that a safety-related solenoid valve, Valcor Model V70900-21-3, was qualified by similarity to a not so similar Model V52600-5291-2 valve. The applicant has already initiated a valve-specific (V70900-21-3) new qualification effort, and successful testing was done at Valcor. The test report is expected to be delivered shortly to the applicant and will be approved before fuel loading. A statement to this effect will be forwarded to the staff.

Subject to the applicant's confirmation that all safety-related component qualification reports are completed and approved, this concern is resolved.

(8) Main Steam System 34-in. Globe Valve Assembly (Containment Isolation) (Part Number 1SM007) and Air Operator (S/N 4-1300)

The staff noted that this valve's instruction manual and maintenance procedures were currently being reviewed as part of the preparation of a formal draft for the ongoing maintenance program. A comprehensive qualification program was evidenced by the available documentation. A staff request for verification that the hydrostatic shell and internal leakage test data were with this valve's document package at the plant site was quickly complied with. The data sheet was approved by the applicant.

Therefore, the applicant has satisfied the operability qualification requirements for this valve.

(9) 8-in. Containment Spray Header Discharge Isolation Gate Valve (Tag No. 1NS-0012B) and Motor Operator (S/N A3157A8)

In case of an accident that required containment spray operation, this valve would be required to open only once. Reclosure would not be necessary.

The applicant did not provide the component test results for the hydrostatic, seat leakage, stroke time tests, and so forth at the time of the audit because such documents were located at the plant site (Catawba) which was a distance away from the audit site at the applicant's headquarters. To expedite the audit, the staff agreed to accept the retrieval of the test results for several of the other audited components as representative of document availability for all safety-related components.

The applicant's specifications did properly specify that the hydrostatic tests were to be performed before seat leakage tests, and the seismic and dynamic load combinations were in accordance with the generic findings previously mentioned. There were no deviations from the specifications. The torque switch setting (90 ft-lb) is adequate and is within a reasonable range of the design torque (8 ft-lb). Aging of valve and actuator components will be addressed on the basis of in-service testing results. The staff noted that the complete assembly of valve and motor was qualified by type test on 4-in. and 12-in. gate valves of 1,500-lb. class design as opposed to the 8-in., 300-lb valves in actual use. The applicant, however, provided a letter from the manufacturer, Westinghouse, which certified that the valve in use has been properly qualified by the type test performed.

Therefore, the applicant has satisfactorily completed the operability qualification requirements for this valve.

(10) 10-in. Safety Injection System Accumulator Tank 1C Discharge Isolation Gate Valve (Tag No. 1NI076A) and Motor Operator (S/N 249636)

This is a normally open valve that is only closed during normal plant cooldowns when the reactor coolant system pressure conditions must be brought below 700 psig. In the event of a large loss-of-coolant accident, the valve must remain open or, if closed, must be signaled to open by the safety injection actuation signal.

As in Item 9 (containment spray header discharge isolation gate valve (tag no. 1NS-0012B)), the applicant did not provide test results at the time of the audit. The applicant's specifications for this component were identical to those for the containment spray valve, except for the system and environmental design differences, which were due to the location of this valve inside the containment. The staff found that the hydrostatic and seat leakage tests were properly specified along with the seismic and dynamic load combinations. There also were no deviations from the specifications. The torque switch setting (3,100 ft-lb) provides adequate margin and is within a reasonable range of the design torque (2,717 ft-lb).

As before, aging of valve and actuator components will be addressed by means of the in-service test results. The complete assembly of valve and motor was qualified by the same type tests as those of the 4-in. and 12-in., 1,500-lb gate valves used for the containment spray valve qualification. The valve in question is a 10-in., 1,500-lb valve.

Therefore, the applicant has satisfactorily completed the operability qualification requirements for this valve.

(11) 42-in. Nuclear Service Water System Header Butterfly Valve (Tag No. 1RN063A) and Motor Actuator (S/N 243617)

This component was picked on the spot as part of the "surprise selection" previously discussed to determine the applicant's ability to retrieve documents and to ascertain the completeness of the central files. The applicant was able to provide appropriate documentation such as a test procedure report for static deflection testing, qualification, seismic and frequency analyses, and purchase specification requirements. All of this documentation was signed and approved by the applicant. Within the limited scope of this review, the applicant satisfactorily completed the operability qualification requirements for this valve.

Conclusion

On the basis of the results of the site review performed at Catawba on March 13-16, 1984, and the subsequent submittals by the applicant to resolve issues identified from the site review, the staff concludes that an appropriate pump and valve operability qualification program has been defined. The continuous implementation of this overall program should provide adequate assurance that the safety-related functions will be performed as needed.

The staff finds that the Catawba pump and valve operability assurance program is acceptable. The applicant should confirm, before initial criticality, that all outstanding qualification programs for safety-related components and accessories have been completed and reflect the latest design parameters and loads (as-built conditions and loads versus initial purchase and design conditions and loads).

This audit required specific qualification confirmations of the Valcor safety-related solenoid valves, Models V70900-301 and V70900-21-3, as discussed under "Specific Concerns," in Items 4 and 7, respectively.

4 REACTOR

4.2 Fuel System Design

Control Material Leaching

In a submittal dated May 16, 1983, the applicant stated that: "After refueling, prior to startup, control rod worth measurements are performed on the control and shutdown banks. Greater than expected worth loss would be detected by this surveillance." The applicant indicated that the intent of his submittal is that the control rod worth measurements will be performed on all of the control and shutdown banks.

On the basis of its review, the staff concludes that the applicant's fuel system design has met all the requirements of the applicable regulations, regulatory guides, and current regulatory positions. The staff finds this acceptable and concludes that License Condition 4 is resolved.

4.4 Thermal-Hydraulic Design

4.4.1 Departure From Nucleate Boiling

In the SER, the staff concluded that the thermal-hydraulic design methodology used by the applicant is acceptable; however, the acceptability of the Catawba design for the departure from nucleate boiling ratio (DNBR) limit required further review. The staff review is now complete and is summarized below.

In a letter dated January 19, 1983, the applicant provided information regarding the nominal value, uncertainty, sensitivity factor and its applicability range of each parameter associated with the improved thermal design procedure (ITDP), and the final design DNBR limits. The nominal values and the sensitivity values of the ITDP parameters are the same as those described in WCAP-9500 except for the DNBR/power sensitivity values for the typical cell and the thimble cell which reflect a finding that the values in WCAP-9500 are reversed. The uncertainty values and the applicability ranges of the ITDP parameters are also the same as those of WCAP-9500 except for the Catawba plant-specific values. In a letter dated December 2, 1982, the applicant provided the measurement uncertainty values for the pressurizer pressure, reactor coolant temperature, reactor power, and reactor coolant system (RCS) flow rate. A detailed measurement component uncertainty breakdown of these parameters and the statistical method of combining these component uncertainties are also provided. The staff has found that the uncertainty values for the pressurizer pressure, reactor coolant temperatures, and core power are acceptable, but the RCS flow measurement uncertainty should be 2.2% compared to 2% described in the report (this will be addressed in Section 4.4.3.3). Based on these parameter uncertainty values and the DNBR limit of 1.17 for the WRB-1 CHF correlation, the staff audit calculation confirms that the final ITDP design DNBR limits of 1.337 and 1.318, respectively, for the typical and thimble cells as reported in the submittal of January 19, 1983, are correct. These values are different from the values of 1.33 and 1.31, respectively, for the typical and thimble cells described in the FSAR and, therefore, changes should be made to the FSAR to reflect the correct design DNBR limits of 1.34 and 1.32 for the typical and the thimble cells, respectively, which are valid for the RCS flow measurement uncertainty up to 2.6%. Since the Catawba design analysis is performed using the plant-specific DNBR limits of 1.49 and 1.47, respectively, for the typical and the thimble cells, there are still 10.1% and 10.2% thermal margins available for the typical cell and thimble cell, respectively, to compensate for other uncertainties such as rod bowing.

4.4.2 Fuel Rod Bowing

In the SER, the staff identified a rod bow penalty of less than 6% DNBR calculated with the approved method described in WCAP-8691, Revision 1. Because there are thermal margins of 10.1 and 10.2%, respectively, for the typical and thimble cells, these margins are more than enough to compensate for the rod bow penalty. The staff will ensure that the available thermal margins and the rod bow penalty being compensated be incorporated in the Technical Specifications bases to avoid multiple use of the thermal margins.

4.4.3 Instrumentation

4.4.3.1 Loose-Parts Monitoring System

In the SER on the loose-parts monitoring system (LPMS), the staff required the applicant to confirm that all the LPMS channels associated with a natural collection region be physically separated in accordance with Regulatory Guide (RG) 1.133, Revision 1, and to commit to provide, before power operation, a final design report. The applicant in a letter dated July 26, 1983, provided a revision to the FSAR. The FSAR revision indicates that Duke will install an additional monitoring channel on each of the 4 steam generators so that the LPMS will have a total of 12 channels and sensor transducers. Two transducers are located diametrically opposed to each other in each natural collection region, i.e., two transducers on the reactor vessel lower head, two on the reactor vessel upper head, and two on the lower head of each steam generator. The additional channels, i.e., sensors, preamplifiers, cables and penetrations, will be physically separated from the existing steam generator LPMS channels. Redundant channels associated with other natural collection regions, i.e., the lower and upper heads of the reactor vessel, will also meet the same separation criteria. In addition, the FSAR revision states that a final design report will be provided on the same schedule as the startup report and will contain a description of the system, a description of applicable station procedures (including results of startup tests), and an evaluation of the LPMS for conformance to RG 1.133. On the basis of this commitment, the staff concludes that the Catawba LPMS is acceptable.

4.4.3.3 Flow Measurement Uncertainty

During reactor power operation, the RCS flow is required to be verified periodically to be no less than the acceptable limit. The RCS flow verification is performed through the flow measurements of the elbow taps located in the cold legs. The elbow tap flow measurements are normalized against a precision flow calorimetric measurement that 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 measurements. By letter dated December 8, 1982, the applicant provided a detailed breakdown of the measurement component uncertainties associated with the flow calorimetric and the elbow tap measurements, as well as the statistical method of combining these uncertainties. The staff review findings follow:

(1) 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 on 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; the hot leg and cold leg enthalpies are both dependent on the pressurizer pressure; and the same digital voltmeter (DVM) is used for all 4 loops. However, they are treated as independent quantities because the magnitudes of the uncertainties of these interdependent error components are so small compared with 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. This conclusion was demonstrated in a safety evaluation report dated June 28, 1983, for the McGuire flow measurement uncertainty analysis. In addition, the uncertainty values used in the analysis are the bounding conservative values that can offset the small error resulting from the statistical treatment of these interdependent error components. Therefore, the staff finds the applicant's treatment of uncertainty values acceptable.

(2) In the calorimetric measurement uncertainty analysis, drift effects of the measurement instrumentation are not included except where necessary because of sensor locations. The applicant indicates that the calorimetric flow measurement is performed within 7 days of calibrating the measurement instrumentation. Therefore, neglecting the drift effect is acceptable. However, by letter (April 10, 1984) the staff requested that the applicant either include provisions in the Catawba Technical Specifications to ensure that the instrumentation calibration be made within 7 days before the performance of the calorimetric flow measurement or that the drift effects of the measurement instrumentation be incorporated in the uncertainty analysis.

    By letter dated April 16, 1984, the applicant responded to the staff's request for additional information. The applicant identified those instruments requiring calibration within a specified time. These instruments are the primary resistance temperature detector (RTD) DVM, feedwater temperature process components, and ΔP cell for feedwater flow measurement. The Catawba feedwater is measured by precision test Type-J thermocouples that have a smaller error band than the reference Westinghouse instrument. These Type-J thermocouples are regularly calibrated with a calibration accuracy of 0.25°F, which includes a drift allowance good for an annual calibration cycle. The feedwater flow ΔP is read by the Ruska DDR-6000 with a quoted error of 0.88% of ΔP as a 90-day specification that includes an allowance for the instrumentation drift. Therefore, a calibration check on the Ruska DDR-6000 will be performed within 90 days of performing the precision heat balance. The DVM used to measure the primary RTDs will be calibrated within 7 days before performing the heat balance. The applicant also indicated that provisions will be included in the plant procedures for ensuring the calibration of those instruments within the specified period. The staff has ensured that this requirement is incorporated in the Catawba Technical Specifications and that the instrumentation drift is properly addressed.

(3) The fouling effect resulting from crud buildup in the venturi is not taken into account in the feedwater flow measurement. Because the venturi fouling is a bias that will result in a higher measured feedwater flow and, in turn, higher RCS flow than the actual values, neglecting the venturi fouling effect on the flow measurement is unacceptable. However, the applicant stated that the venturi fouling will be detected and the venturi shall be cleaned before performing the calorimetric measurement. If the venturi is not cleaned, the effect of the fouling on the determination of the feedwater flow, and, thus, the steam generator power and RCS flow should be measured and treated as a bias, i.e., the error resulting from venturi fouling should be added to the statistical sum of the rest of the measurement errors. The Catawba Technical Specifications have included a provision of 0.1% error to be added to the overall RCS flow error to account for the RCS flow measurement error resulting from venturi fouling. Because an all-volatile chemical treatment will be used in the Catawba plant, significant venturi fouling would not be expected for many years. However, because venturi fouling, if it should occur, would result in nonconservative RCS flow measurement, the staff (by letter dated April 10, 1984) has requested that the applicant institute a monitoring and trending program capable of detecting venturi fouling of 0.1% magnitude or that the Technical Specifications be revised with the appropriate value of venturi fouling uncertainty and the design DNBR limits be modified accordingly.

By letter dated April 16, 1984, the applicant provided a description of the Catawba performance monitoring program. The program includes a monthly review of daily trended data conducted for the purpose of detecting potential venturi fouling. The trended data consist of electrical output, feedwater flow, and first stage pressure. The normal relationship between the electrical output, first stage pressure, and indicated feedwater flow will be established during the first fuel cycle when the venturi is presumed to be clean. During monthly review, the daily trended data of the mean electrical output and mean first stage pressure will be compared with the mean feedwater flow. If the trend of the monthly reviews indicates that the relationship has deviated by 0.1%, corrective action will be taken before performing the next precision balance for the RCS flow measurement. The corrective action will involve either (a) inspecting and cleaning the venturi or (b) quantifying the bias effect of the venturi fouling and making an allowance for it in the RCS flow measurement. The 0.1% value serves as an alarm level at which corrective action must be taken. The staff finds that the venturi fouling concern has been acceptably addressed.

(4) In the elbow tap flow measurement error analysis, the effects associated with the sensor drift and rack drift are included. The component uncertainties associated with the elbow tap flow measurements are the standard

Westinghouse numbers for the process instrumentation and have been previously reviewed and approved for the V. C. Summer Nuclear Station. The staff finds this acceptable for Catawba.

(5) The instrumentation uncertainties used in the analysis are based on the generic bounding values for the Westinghouse instrument. By letter of April 10, 1984, the staff requested the applicant to identify any instrumentation that deviates from the Westinghouse instrumentation and provide the uncertainty value pertinent to this instrumentation and measurement arrangement with comparison to the Westinghouse generic value. If the plant-specific uncertainty value is higher than the Westinghouse generic value, the flow measurement uncertainty analysis should be redone to reflect the higher uncertainty of the Catawba instrumentation.

    By letter dated April 16, 1984, the applicant provided a comparison of the Catawba plant-specific instrumentation error to the Westinghouse generic instrumentation error. A review of this comparison has determined that the DVM used to measure the hot and cold leg temperatures is the only instrument in which the error value exceeds the bounding value of the Westinghouse instrumentation. However, the DVM error is relatively small, and the slightly higher DVM error value has an insignificant effect on the final determination of uncertainties of the reactor coolant enthalpy and flow rate. Therefore, the error analysis using the Westinghouse generic bounding values is acceptable.

(6) The staff has performed an audit calculation based on the bounding values of the component errors and concluded that the uncertainty associated with the precision flow calorimetric is 1.94%, the uncertainty associated with the elbow tap flow measurement is 0.74%, and the overall flow measurement uncertainty is 2.1% for the RCS flow measured by the elbow taps, which are normalized with the precision flow calorimetric. With inclusion of 0.1% for the venturi fouling, the overall RCS flow uncertainty is 2.2% compared to 2.0% proposed by the applicant. The 2.2% RCS flow uncertainty is acceptable for use in the ITDP calculation for the design DNBR limit.

4.4.3.4 Instrumentation for Inadequate Core Cooling Detection

4.4.3.4.1 Clarification of Requirements

A clarification of requirements for inadequate core cooling instrumentation (ICCI), which is to be installed and operational before loading fuel, was provided in Item II.F.2 of NUREG-0737. 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.

4.4.3.4.2 Inadequate Core Cooling Detection System Design

In response to NUREG-0737 requirements, the applicant has transmitted the following:

(1) Attachment 5, "Core Performance," to letter dated January 14, 1983
(2) "Response to Supplement 1 to NUREG-0737" dated September 26, 1983
(3) "Response to TMI Concerns" dated October 19, 1983
(4) "Response to TMI Concerns" dated February 1, 1984
(5) "Response to TMI Item II.F.2 Concerns" dated May 14, 1984

The applicant has selected an ICCI system consisting of three instrumentation subsystems: (1) subcooling margin monitor (SMM), (2) incore thermocouple system, and (3) reactor vessel level instrumentation system (RVLIS).

The primary display of core exit temperature will be the plant computer cathode-ray tubes (CRTs) in the control room, and the backup display will be a Class 1E indicator in the control room.

The applicant plans to upgrade the Catawba emergency operating procedures based on the Emergency Response Guidelines (ERG) developed by the Westinghouse Owners Group. The RVLIS will be incorporated into procedures according to these guidelines. The RVLIS will be fully operational before initial criticality is reached.

4.4.3.4.3 Subcooling Margin Monitor

A subcooling margin monitor will be installed and fully operational by fuel loading to calculate the degree of subcooling using various inputs from RCS pressure and temperature measurements (wide-range and low-range pressures, wide-range hot leg temperatures, and temperatures from incore thermocouples). When RCS pressure is below 800 psig, wide-range and low-range pressure inputs are compared, and, if the inputs agree within 20 psig, the low-range pressure inputs are used. The wide-range pressure inputs are used for the remaining conditions. The incore thermocouple readings (65) are averaged and compared with the four wide-range hot leg temperatures (RTDs). The highest of these temperatures and the appropriate pressure are then used to calculate a conservative margin to saturation. The plant computer is used to average the thermocouple readings and calculate the margin to saturation.

The computer output consists of a CRT graphic display of conservative margin to saturation conditions; that is, a plot of plant pressure and temperature in relation to a computer-generated saturation curve. The computer is powered by highly reliable battery-backed control power. The computer processing and CRT display are located in a mild environment. A procedure to manually calculate subcooling margin, using QA Condition 1 instruments for information, exists as a backup to the graphic display.

The wide-range RTD and wide-range pressure sensor are seismically and environmentally qualified. However, the temperature input from the incore thermocouples is not qualified. In addition to the nonqualified core exit thermocouple (CET) inputs to SMM, the existing SMM does not meet NUREG-0737 Item II.F.2 requirements with respect to the single failure criterion for the display.

4.4.3.4.4 Core Exit Thermocouple System

The present incore thermocouple system has 65 thermocouples positioned to sense exit flow temperatures of selected fuel assemblies. The thermocouples penetrate the reactor vessel head in 5 locations known as instrument ports. Each instrument port has 13 thermocouples. Electrical connection to the Class 1E thermocouples is made at the instrument ports by qualified connectors. The Class 1E thermocouples are cabled to qualified thermocouple penetrations. Twenty (five per quadrant) Class 1E thermocouple channels are provided to ensure that a minimum of four per core quadrant are always operable. The system design accounts for attrition. The nonsafety thermocouples are cabled to reference junction boxes inside containment to allow transition to copper for the remainder of the cabling including the run to an instrument penetration. Outside containment, the Class 1E thermocouples are cabled to reference junction to allow the transition to copper wire. These cables are cabled to the backup display along with the nonsafety thermocouples. The backup display is provided in the control room to read any of the thermocouples. With push-to-read switches, readings can be taken well within the 6-min time guidance. The range of this backup display extends from 200°F to 2300°F. The primary display has direct readout by CRT and hard copy printout capability for all thermocouple temperatures. This readout range extends from 200°F to 2300°F. All thermocouples are cabled from the backup display to the primary display in the plant computer.

The present incore thermocouple system will be upgraded to meet NUREG-0737 Item II.F.2 requirements. From outside the containment, the nonsafety thermocouple cabling will not be altered. However, the Class 1E thermocouple cables will be cabled to a Class 1E backup display directly from the thermocouple penetrations. These thermocouples will be cabled to the primary display using qualified isolation devices. The backup display will be selected as part of the ongoing control board review.

The upgrade of the incore thermocouple system will be completed on Unit 1 by or during the first refueling and on Unit 2 before fuel loading.

4.4.3.4.5 Reactor Vessel Level Measurement

The RVLIS is of standard Westinghouse design for upperhead injection (UHI) reactor systems and uses a microprocessor for data processing. The system consists of two redundant QA Condition 1 channels powered from Class 1E busses. Each channel uses 3 differential pressure (dp) transmitters to measure the pressure drops from the bottom of the reactor vessel to the hot legs for UHI plants and from the hot legs to the top of the reactor vessel. Under natural-circulation or no-circulation conditions, these pressure drops will provide indication of the collapsed liquid level or relative void content in the reactor vessel above and below the hot legs. Under forced-flow conditions, the pressure drops will provide indication of the vessel void content above the hot legs and the relative void content of the circulating primary coolant system fluid. Automatic compensation for changes in the temperature of the impulse lines leading from the reactor vessel and hot legs to the dp transmitters is incorporated in the system. Strap-on RTDs are mounted on the vertical runs of the impulse lines for measuring impulse-line temperatures. Automatic compensation for changes in the reactor coolant system fluid densities also is incorporated in the system.

Following a hypothetical accident that causes a loss of primary coolant, the RVLIS will be used by the plant operators to assist in detecting a gas bubble or void in the reactor vessel and assist in detecting the approach to a condition of ICC. If forced-flow conditions are maintained after the accident, the

RVLIS also will be used to assist in detecting the formation of voids in the circulating primary coolant system fluid. The equipment comprising the RVLIS includes the dp transmitters, impulse lines, impulse-line RTDs, in-containment sensor bellows units, out-of-containment hydraulic isolators, and all the necessary electronic signal conditioning, processing and display equipment. A technical description of the system appears in the Westinghouse manual entitled, "RVLIS - Summary Report, December 1980." The RVLIS will be fully operational by the time initial criticality is reached.

4.4.3.4.6 Staff Evaluation

In letters dated January 14, September 26, and October 19, 1983, and February 1, 1984, respectively, the applicant provided documentation in response to NUREG-0737 Item II.F.2 requirements. The staff has reviewed the applicant's submittals and concludes the following:

(1) The commitment to have two fully operational RVLIS channels before fuel load is acceptable. However, staff review of the final design for acceptability will not be complete until after the installation and preoperational testing of RVLIS system is complete. As requested in the staff's letter of April 10, 1984, the applicant must provide an Implementation Letter Report so that the staff may complete its review for implementation approval of the installed RVLIS system. This report must be submitted within 90 days following completion of the calibration test.

(2) The commitment to upgrade the incore thermocouple system for Unit 1 by or during the first refueling outage and for Unit 2 before fuel loading is acceptable. However, a description of the final backup display should be provided before the first refueling outage.

(3) The existing SMM does not meet the single failure criterion for the display and the seismic and environmental qualification requirement of NUREG-0737 Item II.F.2 with respect to the incore thermocouple inputs. The upgrade of the existing SMM and its TS must be completed before startup after the first refueling outage.

(4) The emergency procedures, which incorporated the generic Westinghouse RVLIS (UHI) for Catawba, must conform with generic emergency operating procedure (EOP) guidelines relating to use of the RVLIS or deviation must be identified and explained before criticality. The staff's review and evaluation of this issue is in Section 13.5.2, TMI Item I.C.1.

Subject to these conditions, the staff concludes that Catawba conforms with the design requirements of NUREG-0737 Item II.F.2.

4.5 <u>Reactor Materials</u>

4.5.2 Reactor Internals and Core Support Materials

A recent board notification (BN 82-81) relates to failure of the support pins that are attached to the bottom of the control rod drive guide tubes in Westinghouse-designed reactors. The support pins align the bottom of the control rod drive guide tube assembly into the top of the upper core plate in a manner that provides lateral support and accommodates thermal expansion of the guide tube relative to the core plate. The Westinghouse analysis indicated that the failures were caused by stress corrosion cracking. Westinghouse now recommends a revised heat treatment for the pins, a revised pin body design, and a reduction in the torque on the lock nut. The applicant has advised that the pins will be replaced and installed in conformance with current Westinghouse recommendations before fuel loading. The staff has been following this problem, including Westinghouse's program. The staff agrees with the Westinghouse analysis and concurs in the revisions that have been made to the design.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.1 Compliance With Codes and Code Cases

5.2.1.2 Applicable Code Cases

As noted in the Catawba SER, the staff's acceptance of American Society of Mechanical Engineers (ASME) Code Cases was contingent upon the applicant supplying a confirmatory list of ASME Code Cases used in the construction of Section III, Class I components within the reactor coolant pressure boundary (RCPB). This information has been supplied in Revision 8 of the FSAR, page 5.2-2 and Table 5.2.1-3.

The staff has reviewed the list of Code Cases and found them acceptable. The staff concludes that compliance with the requirements of these Code Cases will result in a component quality level that is commensurate with the importance of the safety function of the RCPB and constitutes an acceptable basis for satisfying the requirements of GDC 1 and is acceptable. Therefore, Confirmatory Issue 10 is resolved.

5.2.2 Overpressure Protection

5.2.2.1 Overpressure Protection During Power Operation

As stated in the SER, SRP Section 5.2.2 requires that the applicant demonstrate adequate relief protection by assuming that the reactor trip is initiated by the second safety-grade signal from the reactor protection system. The applicant has taken credit for a high pressurizer pressure trip (the first safety-grade primary system trip). The evaluation is supported by a generic sensitivity study of required safety valve flow rate versus trip parameter presented in Westinghouse Topical Report WCAP-7769. In the SER the staff stated that it had requested additional information on the details of this calculation.

The applicant has responded to the staff concerns by letter dated December 10, 1983. In this letter the applicant stated that for safety valve sizing transients as defined in the Catawba overpressure protection report (sent by letter dated May 27, 1983), namely a turbine trip without reactor trip and with concurrent loss of main feedwater, a 2-sec delay of the high-pressure reactor trip would result in a safety valve capacity requirement of 67%. This is compared to a capacity requirement of 40% for a high-pressure reactor trip delay of 1 sec (this delay time is assumed in the Westinghouse Topical Report WCAP-7769). Furthermore, the applicant stated that the maximum required primary safety valve capacity of 86% remains insensitive to the reactor trip delay until the time the fourth reactor trip is to take place, assuming the first three reactor trips did not occur. In WCAP-7769 it is calculated that the steam side safety valve capacity requirement is 100% if only the fourth reactor trip occurs, assuming the first three reactor trips did not occur. At that point, any additional delays will result in a required steam-relieving capacity larger than the steam side safety valve design capacity. This may result in steam side overpressurization and primary side repressurization. However, because these effects may take place only if the first three reactor trips fail, the staff concludes that sufficient safety margin is inherent in this system design. The applicant's analysis (assuming a trip delay of 2 sec) produced a peak reactor coolant system (RCS) pressure of 2,640 psia. This pressure is well within the 110% of design pressure value of 2,750 psia.

The Catawba analyses were performed using the LOFTRAN code, a digital simulation that includes point neutron kinetics, RCS (including the reactor vessel), hot-leg, primary side of the steam generator and cold leg, secondary side of the steam generator and pressurizer surge line. At the time the Catawba SER was issued, the LOFTRAN code was undergoing review; this review has been completed by the staff and the code was found acceptable.

On the basis of the above discussion and because the ASME Code allows full credit for spring-loaded safety valves, the staff finds the applicant's design for overpressure protection during power operation acceptable, meets the criteria of SRP Section 5.2.2, and concludes that Outstanding Issue 7(a) is now resolved.

5.2.2.2 Overpressure Protection During Low-Temperature Operation

As stated in the SER, the applicant has discussed a postulated failure of a dc power bus that would initiate a potential low-temperature overpressure condition by both isolating letdown and disabling one train of the low-temperature overpressure protection system, coupled with the single failure (closed) of the PORV in the unaffected train.

Because the PORVs are equipped with a non-safety-related air supply, two safety-related backup supplies of nitrogen are provided to each of the two PORVs through seismic Category I piping and seismic Category I motor-operated valves (MOVs) and check valves. The first nitrogen backup supply is a nitrogen tank dedicated for each of the two PORVs (see letter dated October 26, 1983). These tanks will contain nitrogen at a high pressure. The nitrogen pressure will be regulated down to that required by the PORV. This safety-related source of backup nitrogen is available during high- or low-temperature operation should the normal air supply pressure fall to a predetermined value. The second nitrogen backup supply is connected to the nitrogen space of two of the four cold-leg accumulators through the pressure regulators, check valves, and MOVs (438A and 439B), which are controlled by a key-lock in the control room. This source of backup nitrogen is available only after the low reactor coolant temperature permissive has been received and the key-lock switch is turned to enable the low-temperature overpressure protection (LTOP) system to operate and to open the two MOVs 438A and 439B. These valves close when the operator returns the key-lock switch to the normal position. The applicant stated that the two MOVs (438A and 439B) are supplied by separate IE power sources and stated that they are qualified to operate in a harsh environment and that the qualification of these valves ensures that accumulator pressure integrity is maintained.

In conformance with BTP RSB 5-2 and SRP Section 6.3, the applicant was requested to commit to the following:

(1) test the low-temperature overpressure protection system to ensure its operability before each shutdown

(2) test the system valve operability as specified in the ASME Code, Section XI

(3) state in the station's Technical Specifications the pressurizer bubble size necessary to ensure that the operator will have at least 10 min after the alarm to terminate the overpressurization transient if the two RHR suction relief valves are not available during low-temperature operation

(4) confirm that the two MOVs, 438A and 439B, are qualified for post-LOCA conditions

(5) lock out the power to these two MOVs in the closed position during normal power operation, or commit to routine check valve leak testing

MOVs 438A and 439B and their electronics were to be included in the above testing commitment.

By letter dated October 26, 1983, the applicant responded to the staff's requests. For Item (1) above the applicant committed to a surveillance frequency consistent with that of the Standard Technical Specification, specifically an analog channel operational test within 31 days prior to entering a condition where LTOP system is required to be operable. The applicant also committed to a channel calibration at least once every 18 months.

For Item (2) the applicant committed to valve inservice testing according to ASME Code, Section XI. The applicant committed to include valves 438A and 439B as Category B valves in the testing program. For Item (3) the applicant has rewired the dc power supplies so that the letdown isolation valves are powered from the dc power bus EDE, one PORV from the dc power bus EPA, and the other PORV from the dc power bus EDF. Each one of these buses is backed by a separate battery. Therefore, under the new wiring arrangement no single failure can both isolate letdown and disable one PORV. This power arrangement renders the LTOP system a single failure-proof system, and eliminates the need for a minimum pressurizer bubble size. For Item (4) the applicant confirmed that 438A and 439B are qualified for post-LOCA environs so that if the valves were subject to a harsh environment from a high-energy leak the valves will still maintain the pressure integrity of the cold-leg accumulators so that these accumulators continue to be available to perform their emergency core cooling system (ECCS) function.

For Item (5) the applicant stated that the two MOVs 438A and 439B are key-locked in the closed position when the plant is in high-temperature operation and these valves act as pressure boundaries for the cold-leg accumulators. They can be opened when the key-lock is returned to the normal position.

If any of the two MOVs were to spuriously move to the open position, the pressure boundary is still intact and protected by seismic Class I piping, a lowpressure regulator, and a soft-seated check valve. If a leak path were to be postulated through an MOV and a soft-seated check valve and if the pressure in the affected cold-leg accumulator decreases to a certain set point, an alarm will sound alerting the operator to the event. The operator can remotely adjust the nitrogen pressure and water level in any accumulator.

The staff finds the applicant's response acceptable and concludes that Outstanding Issue 7(b) is now resolved.

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

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

5.2.4.1 Evaluation of Compliance With 10 CFR 50.55a(g) for Catawba Nuclear Station Unit 1

The SER addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Based on a construction permit date of August 7, 1975, this section of the regulations requires that a preservice inspection program be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet requirements set forth in subsequent editions of this Code and addenda, which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein. The applicant has prepared the Preservice Inspection (PSI) Program based on compliance with the requirements of the 1974 Edition of the Code including Addenda through Summer 1975, except where specific relief is requested.

The staff has reviewed the FSAR through Revision 8 dated January 1984, the Catawba Unit 1 PSI Program Plan through Revision 3 submitted April 16, 1984, and letters from the applicant dated December 1, 1981, April 5, 1982, March 25, 1983, and March 30, 1984. The letter dated March 30, 1984, contained a revised listing of requests for relief from ASME Code Section XI requirements, which the applicant has determined not to be practical. The relief requests address the required volumetric examination of nine pipe branch connection welds between 3 and 6 in. in diameter and the updating to the requirements of later approved Code editions for the visual examination of the pressurizer cladding and the examination for support lug attachments. The applicant provided supporting 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 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. On the basis of the granting of relief from these specific preservice examination requirements, the staff concludes that the preservice inspection program for Catawba Nuclear Station Unit 1 meets the requirements of Section XI of the ASME Code, 1974 Edition including Addenda through Summer 1975, and, therefore, is in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in the Appendix 6A to Section 6.6 of the report. Therefore, on the bases of the discussion above and that contained in Section 6.6 and Appendix 6A, the staff concludes that Confirmatory Issue 11 is resolved.

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

5.2.4.2 Evaluation of Compliance with 10 CFR 50.55a(g) for Catawba Nuclear Station Unit 2

The PSI Program through Revision 3 for Unit 2 was submitted along with Unit 1 in the letter dated April 16, 1984. The applicant has committed to perform the preservice examination of the Unit 2 reactor pressure vessel based on RG 1.150, Revision 1. Because the construction details are not available for portions of some piping systems, the applicant intends to add the selection of the welds to be examined at a later date. The staff will review the Unit 2 program after the document is completed and submitted for review. Requests for relief from ASME Code Section XI requirements, which the applicant has determined not to be practical, will be reviewed after the PSI examinations for Unit 2 have been completed. The staff will complete its review of Unit 2 after the applicant provides the information described above and will present its findings in a supplement to this report.

5.4 Component and Subsystem Design

5.4.2 Steam Generators

5.4.2.3 Steam Generator Modification

The safety evaluation report for the modification to Westinghouse Model D2/D3 steam generators (NUREG-0966) was issued on March 16, 1983. This SER is generically applicable to all nuclear units with this type of steam generator. The Catawba Unit 1 steam generators are Westinghouse Model D3, identical to those in McGuire Unit 2, and nearly identical to those in McGuire Unit 1. Using the installation procedure successfully implemented previously at McGuire Unit 1, personnel from Duke Power Company and Westinghouse modified the Catawba Unit 1 steam generators, installing the flow distribution manifold as reviewed by the NRC in the generic SER. The modification of the Catawba Unit 1 steam generators was completed before fuel loading.

In a report and transmittal letter dated January 17, 1983, the Design Review Panel (DRP) identified the following three specific items to be addressed by each utility:

(1) Provisions should be made for initial monitoring of inlet pressure oscillations.

(2) Plant-specific provisions for ensuring that feedwater flow and/or feedwater temperature restrictions are met should be described, where applicable.

(3) Inservice inspection, eddy current testing, and tube vibration monitoring programs and schedules should be described, where applicable.

As a result of the staff's review of the DRP report, additional requirements were noted in NUREG-0966 in the areas of (1) radiological considerations, (2) quality assurance, and (3) inservice inspection and testing.

The staff has reviewed the means by which the above items will be implemented on Catawba Unit 1.

(1) Inlet Pressure Monitoring

In Section 5.2.1.3 of its report, the DRP recommended that the pressure oscillations in the feedline be initially monitored throughout the design operating flow range.

Catawba Unit 1 was the last affected unit to receive this steam generator modification. Before Catawba Unit 1 is operated at power, substantial operating experience will have been accumulated in previously modified units. For example, McGuire Unit 1 will have been operated for 6 months at full power in the modified condition, shut down and inspected, and returned to power before operation at Catawba Unit 1. On the basis of the similarity between Catawba Unit 1 and other units that will have been modified and operated before Catawba Unit 1 and of the preliminary evaluation of data from McGuire Unit 1, it is concluded that no inlet pressure monitoring or restrictions should be required at Catawba Unit 1. The evaluation of data from McGuire Unit 1, however, is not complete. If, as a result of the final evaluation of the McGuire data, it is determined that inlet pressure monitoring or other restrictions are necessary for Catawba Unit 1, the applicant will be notified.

(2) Feedwater System Changes

Feedwater system piping changes have been made at Catawba to add additional margin for the forward flushing transient. Instead of using forward purge flow to warm the feedline, hot water from the steam generator will be used. This reverse flushing of the feedline eliminates the thermal transient on the manifold and adds additional margin to the stressed bolts. The staff finds this procedure acceptable and in accordance with the requirements of NUREG-0966.

The piping changes are shown on Figure 5.1 with dashed lines. The applicant has committed to evaluate these modifications in accordance with SRP Section 3.6.2. The staff finds this acceptable.

(3) Testing and Monitoring

The DRP recommended that each utility develop inspection, testing, and monitoring programs specific to their plant(s). These programs will verify the hydraulic performance of the modification and give early indication of any structural problems with the manifold. On Catawba Unit 1, this verification will consist of eddy current testing (ECT) and loose-parts monitoring. The ECT program will be evaluated by the staff.

Catawba Unit 1 has an installed loose-parts monitoring system (LPMS) (see FSAR Section 7.8.8 and Section 4.4.3.1 of this report). This system includes two sensors on the lower head of each steam generator. This system, although intended for detecting loose parts in the primary system, has high enough sensitivity to detect a loose manifold. Although extremely unlikely, if a signal is detected on the LPMS, which indicates that one of the manifolds is loose, the unit will be shut down, the NRC will be notified, and appropriate corrective action will be taken. The staff finds the loose-parts monitoring program acceptable.

The applicant had initially proposed to inspect the first five rows of the preheater after completion of the modification on each steam generator. The purpose of this inspection was to identify any damage to the tubes resulting from the modification. As a result of experience in modifying other Model D2/D3 steam generators, Westinghouse has recommended that only the first row of tubes in each steam generator be inspected for damage. If any damage is noted, additional rows would be inspected. This more limited inspection is considered adequate because any modification-related damage to the tubes would be evident in this first row and a 100% eddy current baseline inspection using multi-frequency techniques was previously performed on these steam generators. The staff finds the proposed inspection of the first row of tubes acceptable.

The applicant has proposed no pressure monitoring at the feedline inlet for Catawba Unit 1 modified steam generators. On the basis of a preliminary review of data at McGuire Unit 1, which is of similar design, the staff finds this acceptable. If, however, as a result of the final evaluation of McGuire Unit 1 data, it is determined that inlet pressure monitoring is necessary, the applicant will be notified.

In summary, the staff finds (1) the proposed reverse flushing procedure to limit the fatigue usage on certain modified components is acceptable and meets the requirements in NUREG-0966; (2) the proposed inspection of only the first row of tubes is acceptable; and (3) the modifications of the Model D3 steam generators of Catawba Unit 1 are acceptable. The modified steam generators can be operated at 100% of their design capacity without undue risk to the health and safety of the public. Therefore, Outstanding Issue 8 is resolved for Unit 1, but is under review for Unit 2.

5.4.4 Residual Heat Removal System

5.4.4.1 Functional Requirements

In the SER, the staff asked the applicant to show that cold shutdown can be achieved from the control room by using only safety-related equipment. The staff position allows limited operator action outside the control room, if suitably justified, to correct a single failure. If power is to be locked out of the RHR suction isolation valves in order to satisfy the requirements of the fire protection review, or any other review, the staff's SER indicated that power to these valves has to be restorable from the control room.

The SER stated: to meet the above cold shutdown position, the applicant was required to provide safety-related means to circulate, cool, and depressurize the RCS to the RHR entry conditions. These functions may be achieved through the use of safety-related PORVs and/or safety related high-pressure auxiliary sprays, and safety-related steam generator PORVs. This equipment is not safety related at the Catawba facility.

By letter dated October 26, 1983, the applicant proposed to upgrade the pressurizer PORVs and the steam generator PORVs to safety related.

Two of the pressurizer PORVs are supplied by nitrogen from two of the cold-leg accumulators as a backup to the instrument air system. This nitrogen supply is fully safety related, i.e., safety-related piping, valves and power supplies. This nitrogen supply is only made available at low-temperature operation. To upgrade the pressurizer PORVs to safety related, the applicant proposes to upgrade the qualification of the PORVs and provide a safety-related source of nitrogen for use during normal operation. The PORVs, the nitrogen source, and power supplies will be qualified to perform their safety functions and withstand the worst single active failure and harsh environment inside the containment.

The steam generator PORVs presently have pneumatic actuators. The applicant proposes to replace the existing actuators with electrohydraulic actuators that will be qualified for active modulating service subject to the worst-case environmental conditions of a main steam line break in the "dog house" structure that houses these valves. The applicant committed to implement the above modifications by the end of the first refueling outage for Unit 1 and before fuel loading for Unit 2. Furthermore, the applicant proposes to provide a safety-related electric motor operator (EMO) for the high pressure auxiliary spray valve in lieu of the original pneumatic operator. The applicant committed that this modification will be completed before fuel loading.

There are at least three means available to achieve RCS depressurization: (1) the normal pressurizer spray, (2) three pressurizer PORVs, and (3) an auxiliary pressurizer spray (with safety-related electric motor operator). Additionally, RCS cooldown, using the steam generators, results in an indirect depressurization due to fluid contraction. For the plant to be unable to effect an RCS depressurization, all of the above means would have to be unavailable. Although not specifically quantified, the staff believes the probability of this occurring in the first cycle of operation is low.

Similarly, to achieve heat removal, at least the following means are available: (1) steam dump system and (2) four steam system PORVs. Although the steam system PORVs are not fully safety related, the staff notes the availability of other means for decay heat removal. The staff believes that the likelihood of a simultaneous loss of all these other means is low.

In essence, the applicant is asking for relief from fully meeting the requirements of the RSB BTP 5-1 for the steam generator PORVs and pressurizer PORVs for the first cycle of operation. As noted above, the staff believes the likelihood of total unavailability of the depressurization and heat removal means during the first cycle of plant operation to be small. Therefore, the staff finds the applicant's proposal and implementation schedule acceptable. However, Outstanding Issue 9 has been changed to License Condition 36 until it is fully resolved prior to second cycle operation.

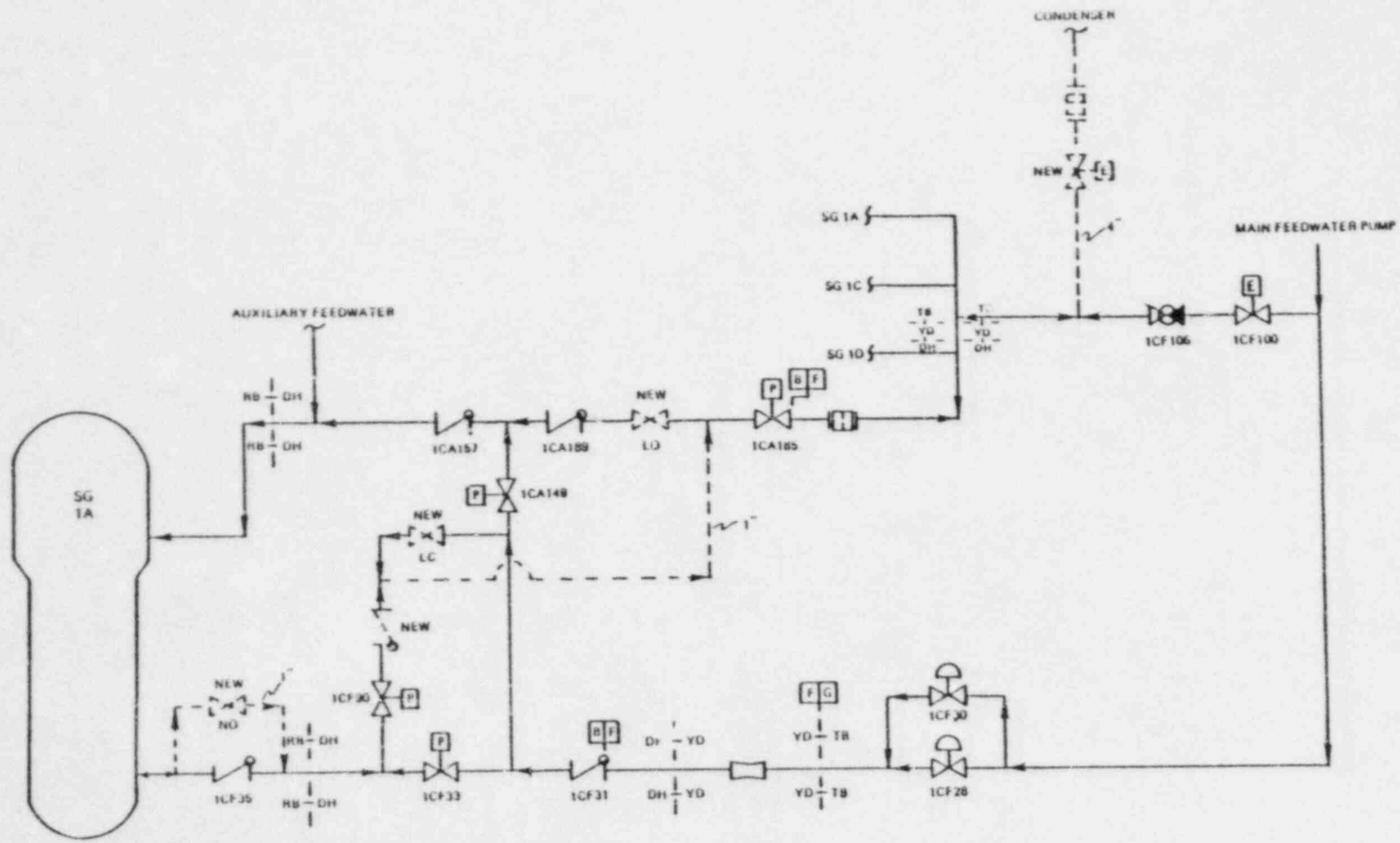

Figure 5.1 Feedwater system changes

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.2 Subcompartment Analysis

Reactor Cavity

The staff stated in the SER that the applicant had not provided sufficient information concerning the calculation of asymmetric blowdown pressure forces and moments acting on the reactor vessel. It was stated that the applicant should show conformance with the provisions of Section 3.2.2.4 of NUREG-0609, "Asymmetric Blowdown Loads on PWR Primary Systems," dated January 1981. The applicant has stated that the design was in conformance with these provisions. However, to substantiate the applicant's statement, the staff requested certain specific additional information, namely, the numerical values of the asymmetric blowdown pressure forces and moments acting on the reactor vessel.

The applicant has provided the requested information by letter dated January 13, 1983, and thus confirmed the conformance of the design with the provisions of Section 3.2.2.4 of NUREG-0609. Therefore, the staff finds the applicant's method of analysis, modeling assumptions, and results acceptable for the evaluation of asymmetric blowdown pressure forces and moments on the reactor vessel. The staff finds the applicant's subcompartment analysis for the reactor cavity acceptable and considers Confirmatory Issue 13 to be resolved.

6.2.1.3 Minimum Containment Pressure Analysis for Performance Capability Studies of ECCS

The staff stated in the SER that the applicant has not considered the effect on containment pressure of containment air lost through containment purge or vent lines open at the beginning of a loss-of-coolant accident (LOCA). This is contrary to the provisions of Branch Technical Position (BTP) CSB 6-1, "Minimum Containment Pressure Model for PWR ECCS Performance Evaluation." The loss of air would reduce the minimum calculated containment pressure, and the staff requires that this effect be considered in the analysis. Although the applicant stated that the effect would be negligible, further information supporting this statement had not been received by the staff before the SER was issued.

The applicant has provided the appropriate information by letter dated June 7, 1983, which referenced the McGuire plant dockets (Docket Nos. 50-369 and 50-370), where the same issue was satisfactorily resolved and accepted by the staff. The effect on containment pressure of air lost through open purge/vent lines is insignificant in the McGuire analysis and, because of the similarity between the Catawba and McGuire Stations, the staff concludes that the effect on the Catawba analysis is also insignificant. Therefore, the staff further concludes that the minimum containment pressure analysis for performance capability studies of the emergency core cooling system (ECCS) is acceptable and considers Confirmatory Issue 14 to be resolved.

6.2.4 Containment Isolation System

The staff stated in the SER that additional documentation was required to confirm the applicant's statement that the design provisions for containment isolation barriers (e.g., Quality Group B, seismic Category I, protection from pipe whip and jets) satisfied the staff's requirements as stated in the SER.

The necessary documentation was included in Revision 7 to the FSAR, and it has been confirmed that the appropriate design provisions for containment isolation barriers have been provided in the Catawba design. Therefore, the staff concludes that Confirmatory Issue 15 has been resolved.

6.2.5 Combustible Gas Control

The staff stated in the SER that measures to control the hydrogen produced from a degraded core accident involving 75% of the active fuel cladding should be implemented at Catawba before initial fuel loading. To satisfy this requirement, the applicant has installed and implemented, in Catawba Units 1 and 2, a distributed hydrogen ignition system that is virtually identical to that installed in McGuire Units 1 and 2. The staff's review of this system was based on its previous review of the McGuire hydrogen control system, which the staff found acceptable. A detailed discussion of that review is provided in Supplement 7 to the McGuire SER (NUREG-0422) and a comparison between the two is discussed below.

The hydrogen mitigation system (HMS) installed at Catawba is identical to that installed at McGuire, except for minor differences in terminal box designation and igniter location. In Supplement 7 to the McGuire SER, the staff found the McGuire HMS to be an acceptable permanent means of degraded-core hydrogen control, subject to implementation of two system design enhancements. The system enhancements involved (1) installation of two additional lower compartment igniters and four additional upper compartment igniters to improve the spatial coverage of the igniter system and (2) relocation of the igniter system switches to permit manual actuation of the HMS from the main control room. These design changes have been incorporated into the HMS at Catawba.

The HMS will be manually actuated when a safety injection signal is received. Procedures for securing the system are identical to those in place at McGuire. To ensure that the HMS will function as intended, Duke has proposed a surveillance testing program identical to that at McGuire.

Although the design of the Catawba HMS and containment building is virtually identical to that of McGuire, the applicant performed a containment response analysis for Catawba. The Catawba analysis was based on the latest version of the CLASIX computer code. This analysis was essentially a reanalysis of the McGuire base case, with minor differences in the allocation of containment volume among the various compartments and the heat structure details. All other CLASIX input parameters were the same as those used in the McGuire analysis. This latest version of CLASIX incorporates corrections in heat transfer models for radiation and convection and in flow path logic for propagating flames. Deficiencies in these areas were identified during the McGuire HMS review; however, reanalysis of McGuire using a revised code was not performed because the deficiencies were judged to provide conservative results.

The CLASIX analysis shows the hydrogen combustion behavior and containment pres sure response for Catawba to be similar to that predicted for McGuire. The maximum containment pressure for the base case was 27.8 psia, compared to 27.6 psia for McGuire. This is below the Catawba containment design pressure of 30.0 psia. A total of 1,022 lb of hydrogen was consumed in 6 lower compartment and 31 upper plenum burns. In contrast, 1,032 lb of hydrogen were consumed in 6 lower compartment and 23 upper plenum burns for McGuire. With regard to containment temperatures, however, the Catawba analysis predicts significantly different results. The containment atmosphere for Catawba is predicted to be approximately 180°F before the first burn and approximately 225°F following the last burn. For McGuire, significantly higher temperatures were predicted; more specifically, 215°F prior to the first burn and 320°F following the last burn. In addition, the ice remaining is predicted to be 3.6×10^5 lb/min for Catawba versus 1.1×10^6 lb for McGuire. These differences in results are attributed to the CLASIX code modifications and the differences in heat sink input.

The staff has reviewed the design and analysis of the HMS at Catawba. On the basis of its evaluation of the HMS design, the staff concludes that the igniter coverage, actuation procedures, and surveillance testing procedures are acceptable. Furthermore, analysis of the containment response indicates that hydrogen combustion associated with the operation of the HMS will not pose a threat to the integrity of the containment.

However, the staff is continuing to investigate a number of issues concerning degraded core hydrogen control and will conclude on these matters before approval of the HMS as a permanent means of hydrogen control at Catawba. The items the staff is investigating include the condensation heat transfer models used in the latest version of CLASIX, equipment survivability for a spectrum of accidents, air return fan and ice condenser door response to upper compartment burns, and igniter spray shield effectiveness. The staff has requested additional information and analyses from the applicant regarding these items and will provide the results of its review in a future supplement to the SER. The staff will condition the Catawba license to ensure satisfactory resolution of these issues.

Accordingly, License Condition 10 remains unchanged. Subject to this condition, the staff finds the measures provided for hydrogen control during postulated degraded core accidents to constitute acceptable measures for full-power licensing of Catawba, Units 1 and 2.

6.3 Emergency Core Cooling System

6.3.1 System Design

As stated in the SER, the applicant has addressed concerns about failure of nonseismic piping in lines connected to the RWST by stating that nonseismic portions would be automatically isolated (using seismically qualified valves) upon receipt of a safety injection initiation signal. Also, the applicant has committed to address the effect of failure of nonseismic piping on the safety injection pump miniflow line and the potential effect of pipe failure on the ECCS availability and performance consistent with GDC 2.

In a letter dated October 26, 1983, the applicant stated that the routing of the safety injection pumps miniflow line has been reviewed. It was concluded that this line is not a target for pipe whip, impingement, or nonseismic pipe failures. The staff concludes that the ECCS availability and performance are ensured and finds the applicant's response acceptable. Therefore, License Condition 13 is resolved.

6.3.2 Evaluation of Single Failures

(1) Compatibility of ECCS Valve Interlocks

As specified in SRP Section 6.3, Subsection II, the staff has reviewed the system description and piping and instrumentation diagrams to verify that sufficient core cooling will be provided during the initial injection phase with or without availability of offsite power, assuming a single failure. The cold-leg accumulators have normally open motor-operated isolation valves in their discharge lines. These isolation valves will have their power removed to preclude inadvertent valve movement that could result in degraded accumulator performance. The UHI subsystem is normally aligned for injection through two parallel lines with normally open isolation valves. When the primary pressure drops below the UHI accumulator pressure, injection to the RCS occurs. An inadvertent valve closure in either discharge line will not preclude UHI. Each UHI discharge line has two isolation valves in series, which are closed automatically when a low level in the UHI accumulator is reached. Failure of a single valve to close will not prevent isolation of the UHI accumulator.

Three active injection systems are available, each system having two pumps. The pumps in each system are connected to separate power buses and are powered from separate diesel generators in the event of loss of offsite power, as required by GDC 17. Thus, at least one pump in each injection train would be actuated. The high-head injection system contains parallel valves in the suction and discharge lines, thus ensuring operability of one train even in the event that any one valve fails to open. The low- and intermediate-head injection systems are normally aligned so that discharge valve actuation is not required during the injection phase.

The applicant has provided the following interlocks to address various single failures:

<u>RHR Pump Discharge to High-Head Injection Pumps</u> - To prevent possible overpressure of pipe during cooldown and to permit alignment to supply pumps only during recirculation.

<u>Containment Sump Valve</u> - To prevent the control room operator from opening the sump valves and flooding containment with fluid from the RWST. The automatic features override the interlocks and open the valve if the RWST level is low and an "S" signal has been generated (this prevents the sump valve from opening and flooding containment during refueling as the RWST is emptied into the refueling cavity).

Charging Pump Normal Suction - To isolate normal charging sources after RWST is available to pumps.

RCS to RHR Isolation Valves - To prevent direct flow from RCS to containment sump spraying reactor coolant to containment through residual spray headers. Also, the pressure interlocks are automatic features that prevent overpressurizing of the RHR pump suction line.

Safety Injection Pump Miniflow - To prevent sump fluid during recirculation from being pumped to RWST.

Containment Spray Suction From Sump - To prevent spill of RWST fluid to containment sump, and to prevent spraying the containment with reactor coolant.

Residual Containment Spray - To prevent spraying the containment with reactor coolant.

The applicant justified the compatibility of these interlocks with the functional requirements discussed in SER Section 5.4.4. The staff finds the justification of the compatibility of these interlocks acceptable and considers Confirmatory Issue 19 resolved.

(2) Charging Pumps Deadheading

As stated in the SER, the applicant addressed single failures and deadheading conditions that could cause the charging pumps to overheat and subsequently fail by removing the automatic isolation "S"-signal of the miniflow line. The staff required that the applicant provide plans to improve his design with automatic features or provide an analysis that addresses the flow degradation in the ECCS design if the miniflow line were left unisolated.

In a letter dated October 26, 1983, the applicant responded to this concern. The applicant reanalyzed the events that required the SI actuation and showed that the secondary pipe break analysis is insensitive to the SI flow changes resulting from an unisolated miniflow line. As for the primary pipe break, the applicant presented a generic Westinghouse analysis for UHI plants and a plant-specific analysis for Catawba (Duke Report-5179, "Reportable Item - Centrifugal Charging Pumps," transmitted by letter July 11, 1980).

The generic analysis was done to determine the effect of variations in pumped safety injection flow on small-break LOCA peak cladding temperatures (PCTs). This analysis was done using the small-break version of the evaluation model for UHI (Westinghouse, December 1974), which was approved by the NRC. The assumptions used were (1) a total loss of one ECCS train, (2) a 20% flow degradation is applied to the charging as well as the safety injection flow of the remaining train, and (3) a delay of 10 min after safety injection initiation and before the operator isolates the miniflow line. On the basis of the above analysis, Westinghouse states that a PCT penalty of 40F° is sufficiently conservative and bounds all UHI plants. Westinghouse further estimates that if the miniflow isolation does not occur at any time into the transient, a PCT penalty on the order of 200F° or more could occur.

The staff concurs that the above Westinghouse assumptions are conservative for the following reasons. If the worst active single failure is chosen as one inoperable ECCS train, the 20% flow degradation need only be applied to the remaining charging pump. Applying this flow degradation to the SI pump is conservative. The Catawba limiting small-break LOCA, as presented in the FSAR, is an equivalent 8-in. diameter, cold-leg break with a PCT of 1,218°F. Therefore, even if no credit for operator action to close the miniflow valve is taken, the limiting small-break LOCA PCT would be expected to increase to about 1,418°F (i.e., 1,218°F plus 200F°), which is still well below the 2,200°F limit.

In light of the substantial PCT margin for the above scenario, the staff finds the applicant's response acceptable. Therefore, the staff concludes that License Condition 12 is now resolved.

(3) Postaccident Environmental Conditions and Their Impact on the Ability of the Operator to Complete Certain Actions Outside the Control Room

As was stated in the SER, the applicant has proposed a partially automatic system with operator action to switch the low-head system from the injection to the recirculation mode. The automatic function of the system opens the RHR pump suction valves from the containment sump and subsequently isolates the RWST. Several valves that would have to be actuated during the switchover are interlocked to other components to prevent out-of-sequence operation. In conformance with SRP Section 6.3, Subsection III.19, the applicant states that where manual action is used in the switch to recirculation, a sufficient time (greater than 20 min) is available for the operator to respond.

In the SER, the applicant was requested to address the environmental conditions that result from postulated events that require the ECCS for their mitigation, and the impact of such conditions on the ability of the operator to complete the necessary manual actions outside the control room following these postulated events.

In a letter dated January 11, 1983, the applicant stated that, following a LOCA, the only action required outside the control room is to establish the hot-leg recirculation. Power restoration to the four valves 152B, 162A, 121A, and 183B is required. This can be done at the motor breakers in a readily accessible area of the auxiliary building. Following a safety injection signal caused by a steamline break, the operator may depressurize the reactor coolant to the residual heat removal (RHR) cut-in point without having to leave the control room because the cold-leg accumulators are pressurized only to 425 psig, which is the operating pressure for the RHR system. The RCS can be cooled to the cold shutdown mode without any nitrogen gas admitted from the cold-leg accumulators. The staff agreed with the applicant and concluded that there is reasonable assurance that the operator will be able to perform the required functions outside the control room within adequate environmental conditions. Therefore, the staff considers Confirmatory Issue 20 to be resolved.

(4) ECCS Override and Reset

In the SER, the staff also asked the applicant to provide procedure guidelines for resetting the ECCS after a safety injection signal. The applicant has committed to implement the generic Westinghouse Emergency Response Guidelines (ERGs) (Westinghouse Owners Group letters OG-64, -76, -83, and -84). These ERGs contain statements to caution and warn the operator that prompt action may be required subsequent to the SI override and reset if the offsite power was lost.

The Westinghouse ERGs have been reviewed and approved by the staff (Generic Letter 83-22, June 31, 1983). The staff finds the applicant's response acceptable and concludes that this issue (Outstanding Issue 10(b), Confirmatory Issue 21) is now resolved.

6.3.4 Testing

6.3.4.1 Preoperational Testing

In the SER, the applicant stated that the available refueling water storage tank (RWST) inventory provides (1) the operator with greater than 30 min after a LOCA to act and complete the ECCS switchover and (2) an available net positive suction head (NPSH) for all the ECCS pumps in their highest flow configuration with adequate margin above the required value.

In a letter dated January 11, 1983, the applicant provided a detailed analysis of the residual heat removal (RHR) pumps' NPSH calculations using conservative assumptions. The applicant showed that for a runout flow of 5,300 gpm the available NPSH would be 24.0 ft while the required NPSH is 23.0 ft.

Therefore, the staff finds the NPSH analysis acceptable and considers Confirmatory Issue 22 to be resolved.

As stated in the SER, the applicant indicated his intent to reference scale model tests performed for McGuire to show the acceptability of the Catawba sump design with respect to vortexing and air entrainment. However, the applicant did not provide quantified detail on the parameters of comparison with McGuire that are adequate enough to show that the McGuire sump tests are applicable to Catawba. The staff required the applicant to identify pertinent parameters (e.g., sump suction pipe submergence) and quantitatively (giving values for each plant) compare them, making sure that these parameters for Catawba also are consistent with the values used in RWST sizing and NPSH analyses.

In a letter dated January 14, 1983, the applicant provided a detailed comparison between the configurations of the McGuire and the Catawba sumps. The staff has reviewed that comparison and concludes that the McGuire sump test is applicable to Catawba and, therefore, the staff finds the applicant's response acceptable. In the same letter, the applicant committed to provide results of a survey quantifying the insulation in the containment by type and location before startup following the first refueling so that the staff may ascertain that such insulation will not block the containment sumps. The staff finds this commitment acceptable, and, therefore, Confirmatory Issue 23 is resolved.

6.3.5 Performance Evaluation

6.3.5.1 Large-Break LOCA

The ECCS must provide abundant core cooling to minimize fuel and cladding damage in accordance with the requirements of 10 CFR 50.46. Topical Report WCAP-8479, "Westinghouse Emergency Core Cooling System Evaluation Model Application to Plants Equipped with Upper Head Injection," describes the Westinghouse calculational model for a pressurized water reactor with ice condenser containment and upperhead injection systems. The staff has reviewed and approved the Westinghouse evaluation model for analyzing LOCAs in UHI plants. In the SER, the staff required further information to justify the adequacy of the break spectrum sensitivity analysis for Catawba.

In response to staff questions 440.100 and 440.129, the applicant explained that Catawba is different from any other UHI Westinghouse plant in that it uses the 17x17 optimized fuel. The applicant also explained that for the double-ended cold-leg guillotine (DECLG) break with a discharge coefficient of 1.0, perfect mixing low-pressure UHI counter current flow regime dominated during the period of interest (86 to 100 sec). For this flow regime the heat transfer coefficient of 1.0 Btu/hour ft^2 °F is imposed by the analysis model (NUREG-0297). For the 0.6 discharge coefficient DECLG break, the heat transfer coefficients are calculated for the low pressure co-current flow in the hot assembly by applying the Dougall-Roshenow correlation. The heat transfer coefficient during the period of interest for this case ranges between 4.7 and 25 BTU/hour ft^2 °F. The different heat removal rates cause the 1.0 discharge coefficient DECLG break to be more limiting than the 0.6 discharge coefficient DECLG break.

In a letter dated May 27, 1983, the applicant presented the results of a spectrum of large LOCAs using the imperfect mixing model. The applicant showed that the DECLG break with a discharge coefficient of 1.0 (perfect mixing) remains the limiting break. This break resulted in a PCT of 2,155°F.

The staff finds the applicant's response acceptable and concludes that Confirmatory Issue 24 is resolved.

6.6 Inservice Inspection of Class 2 and Class 3 Components

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

6.6.1 Evaluation of Compliance With 10 CFR 50.55a(g) for Catawba Nuclear Station Unit 1

The SER addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Based on a construction permit date of August 7, 1975, this section of the regulations requires that a preservice inspection program for Class 2 and Class 3 components be developed and implemented using at least the edition and addenda of Section XI of the ASME Code applied to the construction of the particular components. The components (including supports) may meet the requirements set forth in subsequent editions of this Code and addenda which are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein. The applicant has prepared the Preservice Inspection (PSI) Program based on compliance with the requirements of the 1974 Edition of the Code including Addenda through Summer 1975, except where specific relief is requested.

The staff has reviewed the FSAR through Revision 8 dated January 1984, the Catawba Unit 1 PSI Program Plan through Revision 3 submitted April 16, 1984, and letters from the applicant dated December 1, 1981, April 5, 1982, March 25, 1983, and March 30, 1984. The letter dated March 30, 1984 contained a revised listing of requests for relief from ASME Code Section XI requirements which the applicant has determined not to be practical. The relief requests address the required volumetric examination of four main steam line piping welds enclosed in guard pipe. The applicant provided 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 50.55a(a)(2), have 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. On the basis of the granting of relief from these specific preservice examination requirements, the staff concludes that the preservice inspection program for Catawba Nuclear Station Unit 1 meets the requirements of Section XI of the ASME Code, 1974 Edition including Addenda through Summer 1975, and, therefore, is in compliance with 10 CFR 50.55a(g)(3). The detailed evaluation supporting this conclusion is provided in Appendix 6A to this section of the report.

The initial inservice inspection program has not been submitted. This program will be evaluated after the applicable ASME Code edition and addenda can be determined based on 10 CFR 50.55a(b), but before the first refueling outage when inservice inspection commences.

6.6.2 Evaluation of Compliance With 10 CFR 50.55a(g) for Catawba Nuclear Station Unit 2

The PSI Program through Revision 3 for Unit 2 was submitted along with Unit 1 in the letter dated April 16, 1984. Because the construction details are not available for portions of some piping systems, the applicant intends to add the selection of the welds to be examined at a later date. The staff will review the Unit 2 program after the document is completed and submitted for review. Requests for relief from ASME Code Section XI requirements, which the applicant has determined not to be practical, will be reviewed after the PSI examinations for Unit 2 have been completed. The staff will complete its review of Unit 2 after the applicant provides the information described above and will present its findings in a supplement to this report.

APPENDIX 6A

PRESERVICE INSPECTION RELIEF REQUEST EVALUATION

I. INTRODUCTION

This appendix 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 that are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed therein.

In Revision 3 of the Preservice Inspection (PSI) Program and in letters from the applicant dated December 1, 1981, April 5, 1982, March 25, 1983, and March 30, 1984, the applicant submitted requests for relief from ASME Code Section XI requirements, which have been determined not to be practical. These relief requests were supported by information pursuant to 10 CFR 50.55(a)(2)(i).

Therefore, the staff evaluation consisted of reviewing this 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 August 7, 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 1974 Edition of ASME Code Section XI, including the Addenda through Summer 1975.

B. Verification of as-built structural integrity of the primary pressure boundary is not dependent on the Code 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 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 so examined are capable of subsequent inservice examination using a similar test method. In the case of Catawba 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.

D. 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 (ISI) program. The 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 December 1, 1981, April 5, 1982, March 25, 1983, and March 30, 1984. On the basis of 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. 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, 1974 Edition including Addenda through Summer 1975.

A. Relief Request CN-1-001, Examination Category B-J, Class 1 Branch Pipe Connection Welds

Weld Assembly	Manufacturer's Serial Number	Branch	Size	Outside Diameter
Loop 1:				
Crossover	17002	RTD return	3 in. Sch. 160	6.700
Cold Leg	15177	Pressurizer spray	4 in. Sch. 160	7.200
		Regenerative heat exchanger	3 in. Sch. 160	6.700
Loop 2:				
Crossover	17004	RTD return	3 in. Sch. 160	6.700
Cold Leg	15178	Pressurizer spray	4 in. Sch. 160	7.200

Weld Assembly	Manufacturer's Serial Number	Branch	Size	Outside Diameter
Loop 3:				
Crossover	17006	RTD return	3 in. Sch. 160	6.700
		Regenerative heat exchanger	3 in. Sch. 160	6.700
Loop 4:				
Crossover	17008	RTD return	3 in. Sch. 160	6.700
Cold Leg	15180	Regenerative heat exchanger	3 in. Sch. 160	6.700

Code Requirements: Table IWB-2600, Item B4.6, requires volumetric examination for branch pipe connection welds exceeding 6 in. in diameter.

Code Relief Request: Relief is requested from performing the required volumetric examination on the subject welds.

Reason for Request: Ultrasonic examination is impractical because of the configuration, and radiography cannot be performed for inservice inspection because of accessibility. These branch connection welds would have to be redesigned and replaced to make the welds inspectable. The applicant stated that approximately 20% of the required examination could be performed and that these welds would receive an alternative liquid penetrant surface examination.

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

1. During fabrication the subject welds have received liquid penetrant examinations on the inside and outside surfaces and radiography of the entire weld volume plus ultrasonic examination of the entire volume of the forged nozzle in accordance with ASME Code Section III requirements.

2. For PSI an alternative surface examination was performed in addition to the limited ultrasonic examination.

3. The ASME Code Section III examinations and hydrostatic test along with the limited Code Section XI ultrasonic examination and the alternative surface examination, demonstrate an acceptable level of preservice structural integrity.

B. Relief Request CN 1-002, Examination Category C-G, First Elbow Weld Off the Top of Each Steam Generator (4 welds total)

Weld		Size
Steam Generator A	CT-SM-1A-C	32 in.
Steam Generator B	CT-SM-1B-C	32 in.
Steam Generator C	CT-SM-1C-C	32 in.
Steam Generator D	CT-SM-1D-C	32 in.

Code Requirement: ASME Section XI, Table IWC-2600 Item C2.1 requires volumetric examination for circumferential butt welds. Table IWC-2520 examination category C-G requires that 50% of the total number of circumferential butt welds at structural discontinuities be examined.

Code Relief Request: Relief is being requested from performing the required volumetric examination on the subject welds.

Reason for Request: Guard pipe over the process pipe welds make these welds inaccessible for the Code required examination. The applicant states that there are no alternative examinations that can be performed as a result of the inaccessibility of the welds.

Staff Evaluation: The staff has determined that the preservice volumetric examination of these welds totally enclosed in guard pipe is impractical and concludes that the ASME Code Section III magnetic particle examination performed on the outside surface and radiographic examination on the entire weld volume during fabrication demonstrate an acceptable level of preservice structural integrity.

C. Relief Request CN-1-003, Examination Category B-H, Pressurizer Integrally Welded Supports, Seismic Lugs to Shell and Support Brackets to Shell

Code Requirement: Section XI, Table IWB-2500, Examination Category B-H, requires that 100% of all support lug attachments to Class 1 vessels shall be examined. Section XI, Table IWB-2600, Item B2.8, requires volumetric examination for integrally welded vessel supports.

Code Relief Request: Relief is being requested from performing the required volumetric examination on the subject welds.

Reason for Request: The Inservice Inspection (ISI) Plan will be written to the ASME Boiler and Pressure Vessel Code Section XI 1980 Edition, or later edition if adopted before the operating license is issued. Code Section XI, Table IWB-2500-1, Examination Category B-H, integral attachments for vessels, will require surface examination of these attachment welds. Performing a surface examination for the preservice inspection will provide a basis for comparing future inservice inspection data.

Staff Evaluation: The ISI Plan for Catawba Unit 1 will be written to ASME Code Section XI 1980 Edition, or later editions. Updating to the requirements of later approved editions and addenda is permitted by 10 CFR 50.55a(g)(3)(iv). The staff has determined that this relief request is acceptable as the alternative surface examination performed by the applicant is in accordance with subsequent editions of Section XI referenced by 10 CFR 50.55a(b).

D. Relief Request CN-1-004, Examination Category B-I-2, Pressurizer Cladding

Code Requirement: Section XI, Table IWB-2500, Examination Category B-I-2, requires a visual examination of at least one patch (36 sq. in.) of cladding on the interior cladding surfaces of vessels.

Code Relief Request: Relief is being requested from performing the required visual examination on the subject cladding.

Reason for Request: The ISI Plan will be written to the ASME Code Section XI, 1980 Edition, or later edition if adopted prior to issuance of an operating license. There is no visual examination of cladding required by the 1980 Edition.

Staff Evaluation: The ISI Plan for Catawba Unit 1 will be written to the ASME Code Section XI 1980 Edition, or later editions. This relief request is acceptable because updating to the requirements of later approved editions and addenda is permitted by 10 CFR 50.55a(g)(3)(iv).

IV. CONCLUSIONS

Based on the foregoing, pursuant to 10 CFR 50.55a(a)(2), certain Code 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 Catawba Nuclear 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 a 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.

On the basis of its staff review and evaluation, the staff 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.

7 INSTRUMENTATION AND CONTROLS

7.3 Engineered Safety Features System

7.3.2 Specific Findings

7.3.2.1 Steam Generator Level Control and Protection

In the SER, the staff indicated that the applicant intended to make design changes to ensure that the steam generator high-level trip logic meets the requirements of Paragraph 4.7 of IEEE-Std 279. The applicant's letter of February 1, 1984, stated that the logic for this trip has been changed to two out of four and utilizes an existing fourth steam generator level channel. The staff, therefore, considers Confirmatory Issue 25 closed.

7.3.2.2 Compliance With IE Bulletin 80-06

In the SER, the staff indicated that the applicant committed to perform a test to verify that the actual installed instrumentation and controls are in compliance with the requirements of IE Bulletin 80-06 as part of the Catawba preoperational tests. The applicant's letters of April 25 and June 8, 1984, stated that the tests have been completed and the IE Bulletin 80-06 requirements verified. The staff, therefore, considers Confirmatory Issue 26 resolved.

7.3.2.7 Test of Engineered Safeguards P-4 Interlock

In the SER, the staff indicated that the applicant was permanently installing a voltage indicator to facilitate testing of the P-4 interlock and to minimize the possibility of accidental shorting or grounding of this safety system circuit. The applicant's letter of October 13, 1983, stated that the voltmeter installation has been completed; therefore, the staff considers Confirmatory Issue 27 closed.

7.3.2.10 Containment Pressure Control System

In the SER, the staff stated that the applicant had indicated that the independence of the four sensor channels within the same train is maintained by separating the sensors and cables according to the protection channel separation criteria described in FSAR Section 7.3.2.2.3. The applicant's letter of July 8, 1983, provided written confirmation that this separation criterion is applied to the containment pressure control system sensor channels. The staff considers Confirmatory Issue 28 closed.

7.3.2.11 Lockout of Manual Control by the Load Sequencer

In the SER, the staff indicated that the applicant had been requested to respond to a concern about the safety significance of potential single failures of the Catawba load sequencer that would preclude manual control of sequenced loads. The applicant provided responses to the staff's concerns in letters dated January 14 and July 14, 1983.

The staff's concern relates to the degree of independence that exists with regard to automatically and manually controlled safety actions. Specifically, the load sequencer defeats the manual capability to close or trip switchgear loads until such time as the sequencer and initiating signals have been reset. Further, failures with the load sequencer may result in the failure to start sequenced load or preclude subsequent manual control. However, in some instances, the override of manual control capability may offer some safety benefit to avert operator error from either tripping sequenced loads or starting loads out of sequence. While the staff concludes that current regulatory guidance is not so explicit as to preclude this design, it does favor independence between manual and automatic systems. Therefore, in response to this concern the applicant has proposed that administrative procedures be applied that would permit an override of the load sequencer by appropriate operator action. The staff finds that the applicant's proposed action is acceptable and sufficient to resolve this concern and considers Outstanding Issue 10(a) closed.

7.4 Systems Required for Safe Shutdown

7.4.2 Specific Findings

7.4.2.4 Loss of Both RHR Trains Resulting From a Single Instrument Bus Failure

The staff indicated in the SER that the applicant had been requested to provide the basis that, during decay heat removal, the loss of both residual heat removal (RHR) trains as a result of instrument bus failure does not pose a safety significant issue. The applicant's letter of October 13, 1983, provided a description of his analysis. The analysis showed that under conservative assumptions adequate time--well in excess of 20 min--is available for the operator to take the necessary action to reestablish residual heat removal by either restoring power to at least one train of RHR or providing decay heat removal through the steam generators or the chemical and volume control system. On the basis of its review, the staff finds the design acceptable and considers Outstanding Issue 12 to be resolved.

7.4.2.5 Control Switches for RHR Miniflow Valves

In the SER, the staff indicated that the applicant would modify the control switch configurations to eliminate the neutral switch positions, which prevent the miniflow valves from responding to an automatic open signal required for RHR pump protection. The applicant's letter of June 20, 1983, provided electrical diagrams that detail the design modification and confirm the design change. The staff has reviewed the information provided and finds it satisfactory. The staff considers Confirmatory Issue 30 closed.

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.5 Instrumentation Used To Initiate Safety Functions

In the SER, the staff indicated that the applicant would address the staff's concerns related to indication, alarm, and test features of instrumentation used to initiate safety functions as part of an ongoing control room design review program. The applicant has completed the design review and has identified no new problems related to the staff's concerns. The staff, therefore, considers Confirmatory Issue 31 closed.

7.6 Interlock Systems Important to Safety

7.6.2 Specific Findings

7.6.2.3 Upper Head Injection Manual Control

In the SER, the staff indicated that the applicant would provide a safety-grade manual closure capability for the UHI accumulator isolation valves. The applicant's letter of August 1, 1983, provided electrical diagrams that detail the design modification and confirm the design change. The staff has reviewed the information provided and finds it satisfactory. The staff considers Confirmatory Issue 33 closed.

7.6.2.4 Key-Locked Switches Used to Override Isolation of Control Room Area HVAC System

The staff indicated in the SER that the applicant would modify the isolation circuitry to provide the capability to block isolation signals from a failed detector or monitor, but this would not prevent closure of the isolation valves as a result of a subsequent isolation signal from a nonfailed detector or monitor. The applicant's letter of June 7, 1983, provided electrical diagrams that detail the design modification and confirm the design change. The staff has reviewed the information provided and finds it satisfactory and, therefore, considers Confirmatory Issue 34 closed.

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

In the SER, the staff indicated that an automatic closure system for the PORV block valve would not be required if studies provided in response to Item II.K.3.2 show that the probability for the PORV sticking open is sufficiently small. The applicant's response to Item II.K.3.2 referred to a Westinghouse generic report (WCAP-9804) and stated agreement with the conclusions in that report as applicable to Catawba. The staff has now reviewed the applicant's response and WCAP-9804 and finds that an automatic PORV isolation system is not required for Catawba as noted in Section 15.5.3 of this supplement. The staff, therefore, considers License Condition 14 resolved.

8 ELECTRIC POWER SYSTEMS

8.4 Other Electrical Features and Requirements for Safety

8.4.4 Power Lockout to Motor-Operated Valves

Section 8.4.4 of the Catawba SER indicated that the applicant had not identified the means used to lockout power from valves from which power is removed outside the control room. The applicant also had not indicated whether dual position indication is provided in the control room for the listed valves.

The staff has subsequently reviewed the schematic diagrams covering the design details for motor-operated valves requiring power lockout. Dual position indication is provided in the control room for these valves; however, there is not always two positive indications (two lit lights) for the locked-out position. For example, the indication for a locked open valve may consist of "open" and "closed" lights on one panel and a single "closed" light on another panel. In the locked open position the "open" light would be energized on one panel and the single closed light would be de-energized on the other panel. If the valve should unseat from the fully open position both the "open" and "closed" pair of lights would be energized on one panel and the single "closed" light would be energized on the other panel. The applicant explained that the single de-energized light was necessary in order to follow the panel's design concept (panel is not normally lit).

Because the position indication lights on the two panels provide indication if the valve should come off of the fully locked-out position and because they are fed from separate power supplies and limit switches, they meet the single failure criterion and are acceptable.

The staff has also reviewed the means used to lock out these valves, both locally and from the control room. The valves, which must be controllable from the control room, use a second motor contactor to remove power from the valve motor operator. This contactor is operable from the control room. This meets the requirements of BTP ICSB 18 (PSB) and, therefore, is acceptable.

Power to the valve motors, which have power locked out locally, is removed by opening and padlocking the circuit breakers to the valve motor operator. The padlocking of the circuit breaker is a positive means of ensuring that the circuit breaker remains open and, therefore, is acceptable to the staff.

8.4.5 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

Section 8.4.5 of the Catawba SER discussed the separation of non-Class 1E field run cables and Class 1E circuits. The field run cables are communication, fire detection, and lighting circuits. Some of these cables had been attached to the side rails of essential cable trays or installed in the proximity of Class 1E cables. This practice was discontinued after June 1, 1982. The applicant justified this separation on the basis of the limited power available for the circuits and/or the cable construction and associated manufacturer's fire test results. Also, the Class 1E cables at Catawba have an armored outer sheath that provides additional protection, and the field run cables are attached to the side rails of the trays in most cases, with the rail acting as a barrier.

The staff agreed with the applicant's justification and conclusion that these circuits are unlikely to degrade the Class 1E circuits. However, the staff stated that it would confirm the acceptability of this arrangement during its site visit. The staff would then have a better idea of the number of circuits involved and could get a firsthand view of this installation. The staff has completed its site visit. A number of examples were seen where these circuits were attached to the side rails of non-Class 1E trays. Although many Class 1E cable trays were seen during the course of the visit, only one example was observed where a field run cable was attached to the side rail of a Class 1E tray. The limited number of these circuits found during the site visit and the method of attachment to the trays seen (tray side rail usually acting as a barrier) confirm the adequacy of the installation. On the basis of (1) the justifications originally provided by the applicant and (2) the limited number of circuits involved, the staff concludes that this installation is acceptable and that Confirmatory Issue 35 is resolved.

8.4.7 Flooding of Electrical Equipment

Section 8.4.7 of the SER stated that a number of electrically operated valves are located below the maximum LOCA flood elevation. The applicant had assumed their failure would be in the safe direction but did not discuss what would prevent their failure in the unsafe direction. The applicant also did not address what the effect would be on the Class 1E power supplies that feed the flooded equipment.

The applicant has subsequently provided a modification using latching type relays that prevent a spurious limit switch operation from repositioning the valves when they are flooded. The applicant also has stated that these valves close on a containment isolation signal in sufficient time prior to being flooded. The latching relays have manual reset capability in the control room.

There also are redundant fuses or circuit breakers in the valve circuits coordinated so that, in the case of faults caused by submergence, the faulted valve circuits will be isolated without adversely affecting the upstream Class 1E power sources. The energized circuits in question are limited to those in the valve control power and indication circuits.

The applicant has stated that the subject modifications will be completed before fuel loading. The staff finds the provisions made for the flooding of electrical equipment to be acceptable. This resolves Confirmatory Issue 36 of this report. The adequacy of the environmental qualification of this equipment is addressed in Section 3.11 of this report.

8.4.8 Load Sequencing Design

The staff stated in Section 8.4.8 of the Catawba SER that it will confirm the adequacy of the load sequencer accelerated sequence feature following a review of the Catawba preoperational test results on this system. The accelerated sequence feature had been used at McGuire with satisfactory results but no analysis or tests had been provided for this feature at Catawba.

By letter dated April 18, 1984, the applicant informed the staff that the preoperational test on the train A essential and blackout power systems was recently completed. A part of this test verified proper operation of the accelerated sequence blackout loading. By letter dated June 5, 1984, the applicant has submitted the preoperational test results for the accelerated sequence blackout loading on the train A essential and blackout power systems. The staff has reviewed the applicant's submittal which showed that the loads were successfully sequenced and the voltage and frequency minimum values and recovery times specified by RG 1.9 were not exceeded during the sequencing of the loads. This confirms the adequacy of the accelerated sequence feature at Catawba. Therefore, the staff finds the load sequencer accelerated sequence feature acceptable, and considers Confirmatory Issue 37 resolved.

8.4.10 Load Reduction Capability

Because the Catawba turbine generators have 100% load reduction capability without tripping, the staff questioned the effect of the main generator's voltage and frequency excursions on the safety-related station loads. The applicant subsequently replied that the maximum voltage on the output of the generator would be approximately 129% of rated voltage with the period of the excursion where voltage is above 110% of rated voltage being approximately 3.2 sec. The maximum frequency is estimated to be approximately 107.5% of rated frequency.

The applicant has stated that this overvoltage and overfrequency would not damage power equipment and motors because the equipment is normally designed or tested to levels greater than these values. The staff, however, is concerned about the effect on equipment that uses electronic components because these normally have a lower tolerance to excessive transient voltages and frequencies. The applicant has stated that although industry standards/limits are not available on every type of equipment, industry experience has not indicated a problem with voltage excursions following load rejection.

To ensure that the transient voltages and frequency resulting from 100% load rejection will not damage redundant safety-related equipment, the applicant should either provide additional information on the voltage and frequency excursion levels at other plants with similar load rejection capability or provide information on the tolerance of electronic equipment at Catawba to the overvoltage and overfrequency they have indicated will occur during a load rejection event. The staff will require a license condition that this information be provided and this issue be satisfactorily resolved before a full-power license is issued.

9 AUXILIARY SYSTEMS

In the SER, the staff stated that the review of the safety-related equipment was based on a design temperature of 95°F at the inlet to the nuclear service water system. The staff also stated that the 95°F temperature may change on the basis of an independent analysis. In Section 2.4.4.2 of SSER 1, this temperature was raised to 98.4°F after the independent analysis was completed. Also, the staff stated in SSER 1 that the applicant indicated the affected safety-related equipment will be requalified at the higher temperature.

By letter dated October 13, 1983, the applicant committed to requalify all safety-related equipment at a temperature of at least 98.4°F. By letter dated March 13, 1984, the applicant stated that affected equipment had been requalified at a temperature of 100°F. On this basis, the staff concludes that the safety-related equipment requalification is acceptable. Section 2.4.4.2 of this report discusses the hydrologic and thermal performance acceptability of the standby nuclear service water pond. Thus, as stated in Section 2.4.4.2 of this report, Outstanding Issue 2 is resolved.

9.3 Process Auxiliaries

9.3.2 Process and Postaccident Sampling Systems

9.3.2.2 Postaccident Sampling System

In the SER, the staff found that the applicant's postaccident sampling system (PASS) met 8 of the 11 criteria for Item II.B.3 in NUREG-0737. The following three criteria were unresolved:

Criterion 2 - provide a core damage estimate procedure

Criterion 10 - provide information demonstrating applicability of procedures and instrumentation in the postaccident water chemistry and radiation environment

Criterion 11 - provide information regarding heat tracing of containment sample lines

By letter dated February 7, 1984, the applicant provided additional information. The staff's evaluation follows.

Criterion 2 - The applicant provided a procedure for estimating the degree of reactor core damage based on measured and predicted postaccident radionuclide concentrations from failed fuels. The procedure is identical to that of the McGuire Nuclear Station. The staff determined that these provisions meet Criterion 2; therefore, the procedure for estimating core damage is acceptable on an interim basis. The applicant should provide a final procedure to estimate the extent of core damage based on radionuclide concentrations and taking into consideration other physical parameters such as core temperature data, sample location, and containment radiation levels and hydrogen concentrations. Guidance for the procedure to estimate core damage has been provided to the applicant.

Criterion 10 - The accuracy, range, and sensitivity of the PASS instruments and analytical procedures are consistent with the recommendations of RG 1.97, Revision 2, and the clarifications of NUREG-0737, Item II.B.3, "Postaccident Sampling Capability," transmitted to the applicant. Therefore, they are adequate for describing the radiological and chemical status of the reactor coolant. The analytical methods and instrumentation were selected for their ability to operate in the postaccident sampling environment. Equipment used in postaccident sampling and analyses will be calibrated or tested at least every 6 months. Retraining of operators for postaccident sampling is scheduled at a frequency of once every 6 months. The staff finds that these provisions meet Criterion 10 and, therefore, are acceptable.

Criterion 11 - The applicant has provided information regarding heat tracing of the containment atmosphere sample line to aid in obtaining representative samples. The staff has determined that the applicant meets Criterion 11 of Item II.B.3 of NUREG-0737; therefore, it is acceptable.

The staff concludes that the postaccident sampling system now meets all the criteria of Item II.B.3 of NUREG-0737 and the procedure for estimating reactor core damage is acceptable on an interim basis. Before restart following the first refueling outage, the applicant shall revise the interim core damage estimating procedure by submitting a final procedure that incorporates, as a minimum, hydrogen levels, reactor coolant system pressure, core exit thermocouple temperatures and containment radiation levels in addition to radionuclide data.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection Program

The following partially resolves Outstanding Issue 14 of the SER.

9.5.1.5 General Plant Guidelines

Control of Combustibles

The staff stated in its SER that hydrogen gas would be routed through areas containing shutdown-related equipment. The staff was concerned that the system was not installed in accordance with fire protection guidelines contained in BTP CMEB 9.5-1. By letter dated April 14, 1983, the applicant provided additional information on this system.

The staff has reviewed this system for compliance with BTP CMEB 9.5-1 guidelines. The bulk hydrogen gas storage cylinders are located in the plant yard. Piping within the auxiliary and reactor building are designed to seismic Class I requirements. The two 150-lb cylinders associated with the reactor coolant pump drain tanks also are seismically restrained.

On the basis of the above findings, the staff concludes that the hydrogen gas storage and distribution system complies with Section C.5.d(5) of BTP CMEB 9.5-1 and is acceptable.

9.5.1.7 Fire Detection and Suppression

Fire Detection

In its SER, the staff listed the type of fire detectors used at Catawba Station. By letter dated April 14, 1983, the applicant indicated that ultra-violet and photo-electric-type detectors also are used at Catawba. Because these types of detectors are acceptable, the staff's conclusion regarding this item remains the same.

Fire Protection Water Supply System

The staff stated in the SER that the greatest water demand for fire suppression was 3,420 gpm. By letter dated April 14, 1983, the applicant revised that quantity to 3,645 gpm. In the same letter, the applicant provided the results of acceptance tests on the fire pumps. The results demonstrated that this higher flow rate can be met with the existing system. The performance capabilities of the fire pumps meet Section 6.b of BTP CMEB 9.5-1 and are, therefore, acceptable.

9.5.1.8 Fire Protection for Specific Plant Areas

Safety-Related Battery Rooms

In its SER, the staff expressed concern that redundant dc switchgear and inverters were vulnerable to fire damage. By letter dated April 14, 1983, the applicant indicated that the standby shutdown system will provide a physically and electrically independent safe shutdown capability from the redundant systems in these fire areas. This meets Section C.5.b of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.9 Conclusion

The following two items remain open:

(1) Safe Shutdown Analysis (Section 9.5.1.5)
(2) Description of Standby Shutdown System (Section 9.5.1.5)

The staff will report its review of these unresolved items in a future supplement to the SER.

9.5.3 Lighting System

In FSAR Section 9.5.3, the applicant identified certain vital areas, necessary for plant shutdown, as having only one emergency lighting system, either the emergency ac lighting or the 8-hour battery packs. In the SER, the staff requested that all such vital areas be identified. Revision 8 to the FSAR (Table 9.5.3.2) identified all such areas. The tabulation shows that not all equipment areas have redundant emergency lighting. By letter dated March 23, 1984, the applicant identified the following additional sources of emergency lighting:

(1) At least six battery-operated, 200 W lighting units of the type described in SER Section 9.5.3(4) are stored and maintained as spares. These units are included in the normal surveillance program for this type of lighting.

(2) At least 30 portable lighting units (7.5 V battery) are available. These units are standard stock, consumable items and are not included in a surveillance program.

On the basis of its review, the staff concludes that the various emergency lighting systems provided at Catawba in the vital areas discussed in FSAR Table 9.5.3.2 and supplemented by the emergency lighting sources discussed above, are in conformance with SRP Section 9.5.3 (NUREG-0800) and industry standards. The lighting systems can perform their design functions and, therefore, are acceptable.

9.5.4 Emergency Diesel Engine Fuel Oil Storage and Transfer System

9.5.4.1 Emergency Diesel Engine Auxiliary Support Systems (General)

The applicant was requested in the SER to show that initiation of the automatic CO_2 fire protection systems in the diesel generator building, for whatever reason (seismic event, fire, spurious action, etc.), will not degrade engine startup and operation on demand. In a letter dated May 16, 1983, the applicant stated that the fire detection circuit was seismically designed and supervised to annunciate control malfunctions. Subsequently, the applicant in telephone conversations with the staff stated that the detectors were not seismically qualified. It also was stated in the May 16, 1983, letter that each diesel room is provided with electrically separate CO_2 actuation systems to preclude a common malfunction affecting both diesel rooms. In addition, the ventilation system for the diesel generator rooms is designed so that the CO_2 and products of combustion will not enter the diesel generator air intake. Thus, even though the fire detectors are not seismically qualified, the applicant has stated that an actuation of the CO_2 fire protection for any reason will not degrade the diesel engine starting and operating on demand.

The staff finds the design to be in conformance with the recommendations of NUREG/CR-0660 for enhancement of diesel generator reliability with regard to dust and dirt in the diesel generator rooms. It, therefore, is acceptable and Outstanding Issue 15(c) is resolved.

9.5.8 Emergency Diesel Engine Combustion Air Intake and Exhaust System

In the SER it is stated that the applicant had provided preliminary information on the redesigned diesel engine combustion air intake and exhaust system. At that time the redesigned intake and exhaust structures were found to meet the requirements of GDC 4, the guidelines of RGs 1.115 and 1.117 and NUREG/CR-0660, and the requirements of GDC 2 with regards to rain, freezing rain, snow and dust carryover, and blockage resulting from drifting snow and tornado debris. However, insufficient information was provided on blockage of the intake and exhaust openings as a result of ice and freezing rain and no final drawings were submitted on the redesigned intake and exhaust structures. Thus, the system was found unacceptable because it did not meet the requirements of GDC 2 regarding protection against the effects of natural phenomena.

In a letter dated April 11, 1983, the applicant submitted the revised general arrangement drawings for the redesigned diesel generator air intake and exhaust structures. It also was stated in the letter that the intake and exhaust structure louvers are recessed in the structural openings and protective overhangs are provided in accordance with American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE) recommendations for "Inlet and Outlet Design for Weather and Dust Protection." Louver spacing is greater than 4 in. between blades, thus providing adequate space for ice buildup on the blades without encouraging blockage. Also, the velocity and corresponding pressure drop are low enough to prevent blade icing from compromising the performance of the intake and exhaust system.

On the basis of its review of the submitted information, the staff concludes that the emergency diesel engine air intake and exhaust system meets the requirements of GDC 2, 4, 5, and 17 and meets the requirements of NUREG/CR-0660, the guidance of the cited regulatory guides and SRP Section 9.5.8, and industry codes and standards. The system can perform its design safety function and is acceptable. Therefore, Outstanding Issue 15(b) is resolved.

10 STEAM AND POWER CONVERSION SYSTEM

10.3 Main Steam Supply System

10.3.4 Secondary Water Chemistry

FSAR Section 10.3.4 provided details of a secondary water chemistry monitoring and control program. The staff found that additional information was needed to complete the review; the applicant provided the additional information by letter dated February 15, 1984. The proposed program addresses the six program criteria of the staff's position, as discussed below, and is based on the steam generator water chemistry program recommended by the Steam Generators Owner Group (SGOG).

The program monitors the critical parameters to inhibit steam generator corrosion and tube degradation. The limits and sampling schedules for these parameters have been established for condensate pump common discharge, condensate polisher outlet, deaerator storage tank outlet, steam generator water and steam, and moisture separation drains. The modes covered include normal power operation, startup from hot standby, hot shutdown/hot standby, and cold layup. Sampling frequencies, control points for the critical parameters, and process sampling points have been identified. Plant procedures used for measuring the values of the critical parameters have been similarly identified.

The staff finds that the applicant's secondary side chemistry monitoring and control program

(1) is capable of reducing the probability of abnormal leakage in the reactor coolant pressure boundary by inhibiting steam generator corrosion and tube degradation and thus meets the requirements of GDC 14

(2) adequately addresses all of the program criteria delineated in the staff's position on control and monitoring of secondary water

(3) is based on the SGOG recommended steam generator water chemistry program

(4) monitors the secondary coolant purity in accordance with BTP MTEB 5-3, Revision 2, and thus meets acceptance Criterion 3 of SRP Section 5.4.2.1, "Steam Generator Materials," Revision 2

(5) monitors the water quality of the secondary side water in the steam generators to detect potential condenser cooling water in-leakage to the condensate, and thus meets Position II.3.f.(1) of BTP MTEB 5-3, Revision 2

(6) describes the methods for control of secondary side water chemistry data and record management procedures and corrective actions for off-control point chemistry and thus meets Positions II.3.f.(2)-(6) of BTP MTEB 5-3, Revision 2

Routine changes in the program should be reviewed as per the requirements of Technical Specifications and should be reported under biannual FSAR update as required by 10 CFR 50.71. Nonconservative changes, i.e., relaxation in sample frequency or in impurity limits, should be submitted to NRC for review before the change is implemented. However, all-volatile treatment (AVT) program changes that incorporate boric or calcium hydroxide additions to the steam generator water to further reduce corrosion problems such as tube denting or pitting do not require NRC review provided an evaluation performed in accordance with 10 CFR 50.59 demonstrates that the change does not involve an unreviewed safety question or require a change in the Technical Specifications.

The annual operating report should include an evaluation of the secondary side water chemistry program with an evaluation of the trends and a summary of the total time during the reporting period that the various chemistry parameters were out of the recommended control range.

On the basis of its evaluation, the staff concludes that the proposed secondary water chemistry monitoring and control program meets (1) the requirements of GDC 14 insofar as secondary water chemistry control program boundary material integrity; (2) Acceptance Criterion 3 of SRP Section 5.4.2.1, Revision 2; (3) Position II.3 of BTP MTEB 5-3, Revision 2; and (4) the program criteria in the staff's position and, therefore, is acceptable. Thus, License Condition 19 is considered resolved.

10.4 Other Features

10.4.9 Auxiliary Feedwater System

In the SER, the staff expressed its concern regarding the potential for blocking all suction supply to the auxiliary feedwater (AFW) pumps as a result of inadvertent closure of the single supply line valve (CA103). This concern was incorporated as License Condition 20.

By letter dated September 28, 1983, the applicant stated that valve CA103 has been removed. Removing this valve will not block the water from the primary water source to the auxiliary feedwater (AFW) pumps. The staff finds this acceptable; therefore, License Condition 20 is resolved.

13 CONDUCT OF OPERATIONS

13.3 Emergency Preparedness

13.3.1 Introduction

The staff's evaluation of the applicant's emergency preparedness is provided in Section 13.3 of SSER 1 for Catawba Nuclear Station. The deficiencies identified in that evaluation have been addressed by the applicant in (1) Revision 3 to the Catawba Emergency Plan, June 1983, (2) revisions to the Catawba Emergency Plan Implementing Procedures submitted in July 1983, (3) Revision 9 to Corporate Crisis Management Plan, June 1983, and (4) revisions to the Crisis Management Plan Implementing Procedures, submitted July 1983.

The revised sections of the plans and procedures were reviewed against (1) the appropriate planning standards in 10 CFR 50.47, (2) the requirements of Appendix E to 10 CFR 50, and (3) the specific guidance criteria of NUREG-0654/FEMA-REP-1, Revision 2, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants," November 1980, which has been endorsed by RG 1.101 (Revision 2). The revised plans and procedures also have been reviewed against the deficiencies noted in the earlier review.

13.3.2 Evaluation of the Applicant's Onsite Emergency Plan

The deficiencies identified in SSER 1 are repeated here, followed by the staff evaluation comments.

13.3.2.1 Assignment of Responsibility (Organization Control)

(1) The letters of agreement with the various offsite support agencies should be updated annually.

The applicant has committed to certifying annually that the letters of agreement are current. This satisfies the intent of NUREG-0654.

(2) Duke Power Company's corporate emergency plan should be revised to include Catawba Nuclear Station.

Revision 10 of the Corporate Management Plan, dated October 6, 1983, includes Catawba Nuclear Station except in Table P-2, the section headed "Procedures Used by CMC Dose Assessment Group" does not include Catawba site-specific procedures. The staff considers this to be a part of Confirmatory Issue 42.

13.3.2.5 Notification Methods and Procedures

(1) The station directive for the Technical Support Center (TSC) and the Operations Support Center (OSC) must be generated and approved by station and corporate authorities.

Catawba Nuclear Station Directive 3.8.4, Revision 4 of June 1, 1983, details the alerting, staffing, and activation of the TSC and OSC.

13.3.2.7 Public Information

(1) The public information brochure should be developed and submitted to the staff for review.

The public information brochure for Catawba Nuclear Station, submitted for review June 22, 1983, has been reviewed by FEMA and the NRC. Suggestions for improvement of the brochure have been forwarded to the utility.

13.3.2.8 Emergency Facilities and Equipment

(1) The plan should identify the two-way communications capability between the TSC and the OSC.

The applicant has committed to revising the station emergency plan to include the two-way communications between the TSC and the OSC. The staff finds this commitment to be acceptable.

(2) The plan should describe in detail the equipment and procedures to be used in relaying information from the Field Monitoring Team to the Dose Assessment Group at the permanent Crisis Management Center (CMC)/Emergency Operation Facility (EOF).

The plan identifies Health Physics Procedures HP/0/B/1009/04, "Environmental Surveillance Following a Large Unplanned Release of Gaseous Radioactivity," and HP/0/B/1009/19, "Emergency Radio Operations, Maintenance, and Communications," which provide detailed instructions to the field monitoring teams, both corporate and station, in the equipment and procedures to be used in relaying field survey data to the field monitoring coordinator at the CMC.

(3) The plan should describe the procedures for the CMC in Charlotte in the event of simultaneous emergencies at both McGuire and Catawba Nuclear Stations.

The applicant has reviewed the CMC facilities and staffing plan, and has determined that, in the unlikely event of a simultaneous accident at Catawba and McGuire, the CMC has sufficient facilities available and the key staff positions have several trained alternates available. The applicant has provided additional information and has identified procedures to provide assurance that there would be sufficient resourses available.

(4) The description of the upgraded meteorological system should be revised to clarify the method of obtaining the offsite meteorological data from the National Weather Service (NWS) at Douglas Airport, the applicability of the data to the Catawba site, and the timeliness of these data.

The revised plan directs plant personnel to contact, by Bell telephone, the National Weather Service (NWS) office at Douglas Airport, approximately 13 mi distant, to ensure that basic meteorological information can be assessed. This verifying call will be made monthly by personnel responsible for making offsite dose projections using Health Physics Procedure HP/0/B/1000/6. In an emergency these data are available immediately. Comparison of plant site data with NWS (Douglas Airport) data shows reasonable correlation.

13.3.2.9 Accident Assessment

(1) Procedures to provide the means for relating measured field contamination levels to dose rate and for estimating integrated dose to the population at risk must be generated and approved by station and corporate authorities.

A corporate emergency plan implementing procedure CEPIP-8, "Offsite Radiological Coordination Group," contains a description of the responsibilities, functions, emergency actions and responses of the Dose Assessment Coordinator (DAC) who calculates the doses based on release data, meteorology, monitoring results, and analytical results using dose calculation models, and advises the Offsite Radiological Coordinator (ORC) of the doses to the population-at-risk in the vicinity of the station. The ORC reports to the Recovery Manager and coordinates this information with the Station Emergency Coordinator, the State and local emergency response centers, the Crisis News Director, the NRC advisory support group and others, as appropriate.

13.3.2.10 Protective Response

(1) The applicant will submit maps and information regarding evacuation routes, areas, shelters, preselected sampling and monitoring points, and the population distribution around the facility.

The public information brochure for Catawba, submitted for review on June 22, 1983, contains the maps and information regarding evacuation routes, protective action zones, reception/shelter centers.

Revision 3 of the Emergency Plan for Catawba contains information on the population distribution around the facility by zones and distances.

Health Physics procedure HP/0/B/1009/04 lists in tabular form preselected sampling and monitoring points around the facility.

13.3.3 Conclusions

On the basis of its review of the Catawba Nuclear Station Emergency Plan, previously reported in SSER 1, and a review of the revisions as reported herein, the staff concludes that, upon satisfactory completion of those items identified in Section 13.3.2 of this report as committed to by the applicant, the Catawba Emergency Plan will provide an adequate planning basis for an acceptable state of emergency preparedness.

After reviewing the findings and determinations made by FEMA on the adequacy of State and local emergency response plans and after reviewing any future revisions to the applicant's Emergency Plan, a supplement to this report will provide the staff's overall conclusions as to whether the state of onsite and offsite emergency preparedness provides reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Therefore, Outstanding Issue 16 has been changed to Confirmatory Issue 42.

13.5 Plant Procedures

13.5.1 Administrative Procedures

13.5.1.3 TMI Action Plan Items

I.A.1.1 Shift Technical Advisor

The applicant has by letter dated January 24, 1984, committed to having on shift a shift technical advisor. The applicant plans to have as part of the operating shift crew a shift engineer (shift technical advisor). He shall have a bachelor's degree or equivalent in a scientific or engineering discipline and 2 years of responsible nuclear power plant experience accompanied by an overall knowledge of the plant. The staff concludes that this provision meets Task Action Plan Item I.A.1.1 and is acceptable. Therefore, License Condition 2 is resolved.

I.C.4 Control Room Access

The applicant has developed and issued station procedures that establish specific individual authority and responsibility related to controlling personnel access in the control room during normal and abnormal or emergency conditions. In addition, station procedures have been developed and issued that establish a clear line of authority and responsibility in the control room in the event of an emergency. These procedures also define the lines of communication and authority for station management personnel not in direct command of operations, including those who report to stations outside the control room. The staff finds this acceptable and considers License Condition 24 resolved.

13.5.2 Operating and Maintenance Procedures

I.C.1 Short-Term Accident Analysis and Procedures Revision

The staff's guidance for upgrading emergency operating procedures (EOPs) was provided in the SER. The schedule and review requirements for TMI Task Action Plan Item I.C.1 have been modified by Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability."

Supplement 1 to NUREG-0737 requires that technical guidelines be submitted to NRC for review. For Catawba, this requirement was satisfied by (1) the applicant's commitment in the FSAR to implement a program of emergency operating procedures based on the Westinghouse Emergency Response Guidelines when approved by the staff, and (2) NRC approval of Revision 0 of the Westinghouse Owners Group Emergency Response Guidelines (Generic Letter 83-22, dated June 3, 1983).

NUREG-0737, Supplement 1, also requires that each licensee/applicant submit to NRC a procedures generation package (PGP) at least 3 months before the date formal operator training on the upgraded EOPs is scheduled to begin. The PGP shall include

(1) plant-specific technical guidelines
(2) a writer's guide

(3) a description of the validation/verification program for EOPs
(4) a description of the training program for upgraded EOPs

Review criteria for PGPs are not currently included in the Standard Review Plan (SRP). When SRP Section 13.5.2 was written, the program for the review of EOPs was under development, based on reviews performed for TMI Task Action Plan Item I.C.8. Review criteria for PGPs are being developed based on experience gained in performing the I.C.8 reviews and on NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures," which is the reference document for the EOP upgrade portion of NUREG-0737, Supplement 1. NUREG-0899 identifies the elements necessary for licensees and applicants to prepare and implement EOPs that will provide the operator with directions to mitigate the consequences of a broad range of accidents and multiple equipment failures. In addition, NUREG-0899 outlines the process by which licensees and applicants should develop, implement, and maintain EOPs. To ensure that the elements are addressed in the upgraded procedures and that acceptable processes of development, implementation, and maintenance are used, the staff will review PGPs to gain confidence that EOPs prepared according to the licensee/applicant's program will be acceptable.

The staff's review of PGPs consists of an evaluation of

(1) the applicant's plant-specific technical guidelines, including the planned method for developing plant-specific EOPs from approved generic technical guidelines that are based on the reanalysis of transients and accidents as described in NUREG-0660, Section I.C.1, as clarified in Item I.C.1 of NUREG-0737

(2) the applicant's plant-specific writer's guide, detailing the specific methods to be used in preparing EOPs based on the technical guidelines to ensure that the EOPs are usable, accurate, complete, readable, and acceptable to control room personnel

(3) a description of the applicant's EOP verification/validation program to ensure that the EOPs accurately reflect the technical guidelines and writer's guide, and that the EOPs will guide the operator in mitigating the consequences of transients and accidents

(4) a description of the applicant's program for training operators on EOPs to ensure that the operators will be adequately trained before the EOPs are implemented

The Catawba PGP was submitted by a letter from H. B. Tucker (Duke) to H. R. Denton (NRC), dated February 28, 1983. Subsequently, this PGP was superceded by a revised PGP submitted by a letter from H. B. Tucker to H. R. Denton, dated June 1, 1983. In a letter from H. B. Tucker to H. R. Denton, dated February 22, 1984, the applicant clarified the June 1, 1983, PGP by stating that the NRC-approved version of the Westinghouse Owners Group ERGs, namely, Revision 0 to the ERGs, served as the starting point for the development of the Catawba plant-specific technical guidelines.

The Catawba PGP consists of the seven parts: (1) an introduction describing the purpose, scope, and contents of the PGP; (2) a discussion of the Westinghouse Owners Group ERGs used as the applicant's basis for developing plant-specific technical guidelines and plant-specific EOPs, along with a description of the EOP development process; (3) the Catawba Nuclear Station Writer's Guide that provides instructions for writing procedures, emphasizing the incorporation of human factors engineering principles; (4) a description of the verification program used to confirm the correctness and technical accuracy of the procedures; (5) a description of the validation program for ensuring that a trained operating shift can manage emergency conditions using the plant-specific EOPs; (6) a description of the training program for control room operating personnel, including discussion of classroom, inplant, and simulator training; and (7) status of the applicant's program for upgrading EOPs.

As previously discussed, detailed criteria for review of PGPs do not exist. The Catawba review was based on the requirements of Supplement 1 to NUREG-0737. NUREG-0899 provided additional guidance for the review.

As a result of its review of the Catawba PGP, the staff finds that the following items need to be resolved before the staff can conclude that the applicant's program for developing procedures in accordance with TMI Task Action Plan Item I.C.1 is acceptable. Item 1 must be resolved before initial criticality. Item 2 consists of several minor issues that should be resolved before an operating license is issued.

(1) In the February 22, 1984, letter from H. B. Tucker to H. R. Denton, the applicant stated that Revision 0 of the ERGs served as the starting point for the Catawba plant-specific technical guidelines. The applicant also stated that some changes had been made to the Catawba plant-specific technical guidelines to conform with Revision 1 of the ERGs. These changes are briefly summarized in the February 22, 1984, letter from the applicant. In addition, Section 6.2.2.1 of the PGP states that major differences between the Catawba design and the reference plant are being considered in additional analyses performed by Westinghouse. Examples of these differences are the ice condenser containment and upper head injection system used in the Catawba design.

    The staff requires the applicant to identify the safety-significant differences in the Catawba plant-specific technical guidelines from the NRC-approved generic technical guidelines and to provide justification for these deviations. This information shall be reviewed and approved by the staff before initial criticality.

(2) Additional information and/or clarification is needed in the following areas:

    (a) The PGP should contain a more complete description of how adequate operator and plant staff familiarization with EOPs will be ensured before EOP implementation. This description should (i) include a commitment that all EOPs will be exercised by all control room operators during simulator training, (ii) identify the method for ensuring adequate operator training of areas not covered by simulator exercises, and (iii) describe the method of documenting the simulator program, including provisions for evaluation and documentation of operator performance.

(b) The PGP should contain a description of the criteria used for selecting the scenarios used in the validation/verification program to provide a high level of assurance that the procedures will properly guide the operators in mitigating the consequences of transients and accidents. The program description should indicate that the full complement of EOPs will be exercised (including multiple failures, both simultaneous and sequential).

(c) Section 2.5 of the Catawba Writer's Guide correctly states that action steps should not be included in cautions or notes. However, in the Emergency Procedures Example in Appendix I to the Writer's Guide, the cautions on pages 3 and 4 do include action steps. Either the action steps should be removed from cautions or the Writer's Guide should be revised to describe when it is permissible to include action steps in cautions.

(d) Section 5.5.3 of NUREG-0899 states that "WARNINGS and CAUTIONS should be written so that they can be read completely without interruption by intervening steps or page turning." Section 2.5 or other appropriate location in the Catawba Writer's Guide should include a statement to this effect.

(e) Section 5.5.8 of NUREG-0899 contains guidance for the preparation of figures and tables. Section 2.9 or another appropriate location in the Catawba Writer's Guide should include such guidance to ensure accuracy of information presentation to facilitate access and usability.

(f) Describe the method for handling differences between Catawba Units 1 and 2 in the validation/verification and training process, e.g., to the extent that the units differ in terms of instrumentation, controls, equipment (including availability, design, labeling, or location) or any other aspect that may impact safety of plant operation or maintenance.

The staff concludes, with the exception of these items, that the applicant's program for developing of EOPs as required by NUREG-0737, Item I.C.1, and Supplement 1 to NUREG-0737, is acceptable. Therefore, Item I.C.1 becomes License Condition 34 in this supplement.

13.5.3 Reanalysis of Transients and Accidents, Development of Emergency Operating Procedures

I.C.7 NSSS Vendor Review of Procedures

The requirement for vendor review of EOPs has been satisfied by the involvement of Westinghouse in the development of the ERGs, as reported under TMI Task Action Plan Item I.C.1 of this supplement. The applicant's EOPs will be based on the ERGs. In addition, Westinghouse is performing analyses of differences between Catawba and the reference design used in developing the ERGs to be used in developing the plant-specific technical guidelines. Therefore, the staff finds, the applicant has adequately responded to TMI Task Action Plan Item I.C.7 for EOPs. NSSS vendor review of low-power testing and power ascension procedures as discussed in Section 13.5.3 of the SER remains as License Condition 25 in this supplement.

15 ACCIDENT ANALYSIS

15.1 General Discussion

Review of thermal hydraulic code THINC-IV is described in Section 4.4 of the SER. The LOFTRAN code has been reviewed and approved by the staff (letter from C. Thomas (NRC) to E. Ray (Westinghouse), July 29, 1983). The staff review of the FACTRAN code has progressed to such a point that there is reasonable assurance that analyses results dependent on the code will not be appreciably altered by any revisions that may be required by the staff. For some events analyzed in Section 15, the applicant used an improved thermal design method (described in SER Section 4.4). The staff has requested that the applicant clearly identify the events for which this method was used and show that implementation of this method conforms to appropriate restrictions and limitations. Because this issue is identified as Outstanding Issue 5 in Section 4.4.1 in Supplement 1 of the Catawba SER (NUREG-0954, April 1983), it is being removed from this section as Confirmatory Issue 39.

15.2 Normal Operation and Anticipated Transients

15.2.4 Reactivity and Power Distribution Anomalies

15.2.4.5 Rod Cluster Control Assembly Malfunctions

SSER 1 indicated that, as a result of the staff approval of the new Westinghouse analytical methodology for the control rod drop event and the topical report describing it, the related operating restrictions were not needed for Catawba cycle one. The staff has subsequently determined that the cases presented in the topical report are not necessarily directly applicable to Catawba cycle one and that reactor-specific calculations are required. These calculations, using the approved Westinghouse methodology, have been done and the required criteria have been met. These calculations are presented in Amendment 30, Revision 8, to the Catawba FSAR. The staff review has concluded that appropriate reactor-specific calculations have been completed for Catawba and operating restrictions are not required for cycle one.

15.3 Design-Basis Accidents

15.3.4 Reactor Coolant Pump Rotor Seizure and Shaft Break

As stated in the SER, the reactor coolant pump locked-rotor accident was analyzed by postulating an instantaneous seizure of one reactor coolant system pump rotor. The reactor flow would decrease rapidly, which leads to a reactor trip as a result of a reactor coolant low-flow signal. In response to a staff question, the applicant stated that for the case of a loss of offsite power, no fuel rods are calculated to experience a departure from nucleate boiling ratio (DNBR) value less than the acceptance limit and, hence, no fuel failure resulting from locked-rotor event. Because there is no fuel failure calculated for this accident at Catawba, there is no single active failure that will cause the consequences to exceed 10 CFR 100 limits.

The staff finds the applicant's response acceptable and, therefore, concludes that Confirmatory Issue 40 is now resolved.

15.4 Radiological Consequences of Design-Basis Accidents

15.4.4 Steam Generator Tube Rupture

On February 24, 1984, a meeting was held with several NTOL applicants that use the Westinghouse nuclear steam supply system (NSSS) in their facilities, to discuss the proposed Westinghouse Steam Generator Tube Rupture program. The meeting summary, dated March 7, 1984, provides a brief outline of the issues discussed among the NRC staff, Westinghouse, and the NTOL applicants. By letter dated May 25, 1984, the staff requested the applicant to provide additional information related to this area. Until the applicant provides a submittal for staff review and approval, the staff will condition the license to require that such submittal and approval be made before startup following the first refueling outage.

15.4.6 Fuel-Handling Accident

On July 26, 1983, the applicant committed to upgrade the non-ESF-grade containment purge ventilation system in order to receive credit for an efficiency of 90% elemental and 70% organic removal by the atmospheric cleanup system during and following an accident occurring inside containment. The applicant will install a 100-kW electric heater upstream of the atmospheric cleanup system high-efficiency-particulate-air (HEPA) and charcoal filters, and provide controls to isolate the system on high radiation or high relative humidity signals. The heater will be set to maintain less than or equal to 70% relative humidity in the inlet air. A second humidity controller will ensure a suitable atmosphere in the adsorber section during periods of shutdown/isolation of the system. The Technical Specifications will include requirements to maintain the HEPA and charcoal adsorbers to the guidelines specified in RGs 1.52 (Rev. 2) and 1.140.

On the basis of this modification, the staff considers the atmospheric cleanup system for the containment purge ventilation system acceptable for the credit assumed in the analysis in the SER for the fuel-handling accident (Section 15.4.6, NUREG-0954). The staff considers Confirmatory Item 41 to be resolved.

15.5 NUREG-0737 Items

15.5.1 Thermal Mechanical Report (II.K.2.13)

As stated in the SER, the Westinghouse Owners Group submittal regarding the thermal mechanical analysis was being reviewed by the staff. The staff has recently completed its review and concluded that the information provided is adequate in demonstrating reasonable assurance that vessel integrity is maintained for an Action Plan Item II.K.2.13 event. The staff's conclusions regarding this issue, which is related to Unresolved Safety Issue (USI) A-49, "Pressurized Thermal Shock," are based on findings related to USI A-49. Based on its review, the staff finds that the applicant has satisfied the requirements set forth in TMI Action Item II.K.2.13. Therefore, License Condition 29 is resolved.

15.5.2 Voiding in the Reactor Coolant System During Transients (II.K.2.17)

As stated in the SER, the Westinghouse Owners Group (WOG) undertook a study (WOG-57, R. W. Jurgensen, Westinghouse Owners Group, to P. S. Check, NRC, April 20, 1981) to ascertain the potential for void formation in Westinghouse reactors during anticipated transients. For this study, Westinghouse used the WFLASH computer program, which models the RCS with nodalized volumes. The staff has reviewed WOG-57 and concludes that the analyses performed for the anticipated transients reported in the licensing documentation of these Westinghouse plants account for the effects of void formation in the reactor coolant systems.

The staff concludes that the voids generated in the reactor coolant systems of these Westinghouse plants during anticipated transients are accounted for in present analysis models (i.e., FLASH-4 and LOFTRAN computer programs). Furthermore, based on transient analyses performed by Westinghouse using these models, the staff further concludes that these steam voids will not result in unacceptable consequences during anticipated transients in any of these Westinghouse plants. Therefore, the staff considers License Condition 30 resolved.

15.5.3 Installation and Testing of Automatic Power-Operated Relief Valve Isolation System (II.K.3.1) and Report on Overall Safety Effect of Power-Operated Relief Valve Isolation System (II.K.3.2)

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 has asserted that the generic report was applicable to Catawba. Based on the similarity of the safety valves (Dresser type 6-31749A) to those used by some other Westinghouse plants (North Anna Units 1 and 2), and based on the Electric Power Research Institute (EPRI) test results (EPRI NP-2628, 1982), the staff estimates the failure rate of the Catawba safety valves (SV) to be similar to that of other Westinghouse plants, 1×10^{-2}/demand. Because of similar design and operation of the plant, the staff expects a similar SV challenge frequency to that of other Westinghouse plants. Therefore, the staff's estimate of the frequency of a small-break loss-of-coolant accident (SBLOCA) resulting from a stuck-open SV is 3×10^{-4}/reactor-year, the same as for other Westinghouse plants.

The PORVs at Catawba are similar to those at McGuire, and the staff estimates a similar PORV challenge frequency at McGuire and Catawba because of similarity in plant design and operation. The analysis presented in the staff's letter of March 13, 1984, to H. B. Tucker (Duke) from T. M. Novak (NRC) on McGuire is therefore applicable to Catawba. The staff estimate of SBLOCA frequency, resulting from a stuck-open PORV, is 1.5×10^{-3}/reactor-year.

The staff, therefore, has 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, the staff considers License Condition 14 resolved, although the staff notes that a cost-benefit analysis was not done.

15.5.6 Small-Break LOCA Methods (II.K.3.30) and Plant-Specific Calculations (II.K.3.31)

As stated in the SER, the applicant has referenced the Westinghouse Owners Group submittal regarding this issue. The staff's review of this submittal has not been completed. The applicant has stated that it is a participant in the Westinghouse Owners Group on this issue. This issue is being actively pursued by the staff on a generic basis. On the basis of the above information, the staff considers License Condition 32 resolved.

15.6 Anticipated Transients Without Scram

As stated in the SER, the applicant is required to have procedures for mitigating the consequences of anticipated transients without scram (ATWS) events. The Westinghouse Owners Group has developed ERGs that include actions for mitigation of ATWS events. The applicant's EOPs will be based on ERGs that are approved by the staff. Therefore, the staff concludes that the applicant has adequately responded to the NUREG-0460 requirement to have EOPs for mitigating the consequences of ATWS events.

18 CONTROL ROOM DESIGN REVIEW

18.1 Position

Action Plan Item I.D.1, "Control Room Design Reviews" (NUREG-0660), states that operating reactor licensees and applicants for operating licenses will be required to perform a detailed control room design review (DCRDR) to identify and correct design discrepancies. The objective, as stated in NUREG-0660, is to improve the ability of nuclear power plant control room operators to prevent or cope with accidents, if they occur, by improving the information provided to them. Supplement 1 to NUREG-0737, dated December 17, 1982, confirmed and clarified the DCRDR requirement in NUREG-0660. As a result of Supplement 1 to NUREG-0737, each applicant or licensee is required to conduct their DCRDR on a schedule negotiated with NRC.

NUREG-0700 describes four phases of the DCRDR to be performed by the applicant and licensee. These phases are (1) planning, (2) review, (3) assessment and implementation, and (4) reporting.

The draft of NUREG-0801, "Evaluation Criteria for Detailed Control Room Design Review," provides the necessary criteria for evaluating each phase.

Supplement 1 to NUREG-0737 requires applicants and licensees to submit a program plan that describes how they will

(1) establish a qualified multidisciplinary review team

(2) perform a function and task analyses to identify control room operator tasks and information and control requirements during emergency operations

(3) compare display and control requirements with a control room inventory

(4) survey the control room to identify deviations from accepted human factors principles

(5) assess human engineering discrepancies (HEDs) to determine which HEDs are significant and should be corrected

(6) select design improvements

(7) verify the selected design improvements will provide the necessary correction

(8) verify that improvements will not introduce new HEDs

(9) coordinate control room improvements with changes from other programs such as the safety parameter display system (SPDS), operator training, RG 1.97 instrumentation, and upgrade of emergency operating procedures

The NRC requires each applicant and licensee to submit a summary report at the end of the DCRDR. The report should describe the proposed control room changes and implementation schedules and provide justification for leaving safety significant HEDs uncorrected or partially corrected.

The staff will evaluate the organization, process, and results of each DCRDR. The evaluation of the applicant's and licensee's DCRDR efforts will consist of the following, as described in NUREG-0801:

(1) an evaluation of the program plan report submitted by the licensee/applicant

(2) a visit to some of the plant sites to audit the progress of the DCRDR programs

(3) an evaluation of the licensee/applicant DCRDR summary report

(4) a possible preimplementation audit

(5) the preparation of a safety evaluation report that will present the results of the NRC evaluation

Significant HEDs should be corrected. Improvements that can be accomplished with an enhancement program should be done promptly.

18.2 Discussion

Duke Power Company submitted a generic "Control Room Review Plan" to the NRC on April 14, 1983, for performing DCRDRs for all units of the Oconee, McGuire, and Catawba Nuclear Stations. The staff reviewed the program plan with reference to the requirements of Supplement 1 to NUREG-0737 and the guidance contained in NUREG-0700 and Draft NUREG-0801 and transmitted comments to Duke Power by letter, dated August 2, 1983. Also, by the letter of April 14, 1983, the applicant submitted a Control Room Review Final Report as an attachment to his response to NUREG-0737, Supplement 1, and, by letter dated June 1, 1983, submitted a Control Room Review Supplement (dated May 6, 1983) to the Final Report for the Catawba Nuclear Station Unit 1. In conjunction with the staff's review of the Catawba Unit 1 DCRDR Summary Report and the preparation of the SER on the Catawba Unit 1 DCRDR, the staff conducted a preimplementation audit of Catawba Unit 1 and an in-progress audit of the remaining Duke nuclear stations on August 9-12, 1983. Consultants from Lawrence Livermore National Laboratory (LLNL) assisted the staff in its review. LLNL's Technical Evaluation Report can be found as Enclosure A to a letter dated March 9, 1984, from NRC to Duke transmitting the DCDR preliminary draft SER. By letter dated Apr[illegible], 1984, the applicant provided written responses to each of the open items identified in the staff's letter of March 9, 1984.

The following is a brief summary of the degree to which the requirements of Supplement 1 to NUREG-0737 were satisfied. Additional detail describing how Duke conducted the Catawba Unit 1 DCRDR can be found in Enclosure A to the above-mentioned letter.

(1) Establishment of a Qualified Multidisciplinary Review Team

Duke established an 11-member interdisciplinary management steering committee to direct and manage the DCRDR and an interdisciplinary review team to work on the DCRDR. Six members of the review team were designated as the core review team and assigned to work full time on the DCRDR.

Duke's DCRDR planning and organization generally follow the guidelines of NUREG-0700 and Draft NUREG-0801. The review team was supported by well-qualified human factors consultants.

In summary, it is the staff's judgment that the applicant has met the requirement of establishing a qualified multidisciplinary review team.

(2) Function and Task Analyses to Identify Control Room Operator Tasks and Information and Control Requirements During Emergency Operations

Duke conducted a function and task analysis based upon the Westinghouse Emergency Response Guidelines (ERGs) issued in September 1982. Procedures for all emergency operations were analyzed and some normal operating procedures also were analyzed. The applicant's objectives in performing the task analysis were identification of operator tasks, determination of the controls and displays required to perform those tasks, and evaluation of the human factors suitability of the controls and displays.

The task analysis team developed operational sequences for all ERGs and for selected normal operating procedures to define operator tasks and task-elements that established information and control requirements. The task/task element descriptions were then used with operational sequence talk-throughs and walkthroughs to identify potential HEDs. The Catawba Unit 1 task analysis identified 112 potential HEDs.

Duke's function and task analysis for Catawba Unit 1 was audited by the staff during the preimplementation audit because neither the program plan nor summary report described in sufficient detail how the objectives of the task analysis were going to be accomplished. The task analysis audit included a review of the Duke task analysis documentation and detailed discussions with the personnel who conducted the task analysis. The audit verified that the task analysis was performed on all operational sequences identified in the Westinghouse ERGs and selected normal operation sequences. The audit team reviewed (a) selected task data packages consisting of task sequence charts, (b) completed task data forms that included identification of information and control requirements, and (c) HED documentation orginating from the task analysis. In addition, the audit team selected the ERG for steam generator tube rupture and conducted a detailed walkthrough and evaluation of the task sequence using Duke's task sequence charts and task data forms and the full scale control room mockup

Based on the operator tasks identified, the applicant defined the parameters necessary for the operators to determine the need to perform the tasks and the parameters necessary to determine that the tasks have been performed successfully. The operator's tasks were analyzed to determine the characteristics of the information and control capability needed to perform the task. Information characteristics included parameter type, dynamic range, set points, resolution/accuracy, speed of response, units, and the need for trending. Control characteristics included type (discrete or continuous), discrete function (e.g., On, Off, Auto), rate, gain, response requirements, transfer function, criticality, and frequency of use.

On the basis of the audit of Duke's system function and task analysis, it was the staff's judgment that the applicant had basically met the requirement for conducting the system function and task analysis. Since the audit, the staff has met with the Westinghouse Owners Group (WOG) on the task analysis requirements. The staff has discussed the results of the WOG meeting with the applicant and further confirmed the adequacy of the Catawba Unit 1 task analysis.

(3) <u>A Comparison of Display and Control Requirements With A Control Room Inventory</u>

While Duke Power did not conduct an explicit control room inventory, an inventory was compiled during construction of the photo-mosaic mockup of the Catawba Unit 1 control room. All components on the mockup were labeled and identified with their engineering drawing identification number.

Lack of needed control room instruments and controls was identified during the task analysis talkthroughs and walkthroughs conducted at the control room mockup. Systematic identification of unnecessary controls and displays was not performed. A listing of emergency equipment, communications equipment, and reference materials to be provided in the control room was compiled during the control room survey.

The activities performed by Duke during the task analysis and control room survey activities enabled the staff to conclude that the applicant has met the intent of the requirements of comparing display and control requirements with a control room inventory.

(4) <u>A Control Room Survey To Identify Deviations From Accepted Human Factors Principles</u>

Duke conducted a control room survey (CRS) of Catawba Unit 1 to determine the extent that control room equipment and components were in compliance with human factors guidelines. The Catawba Unit 1 CRS was divided into three separate surveys:

(a) a physical survey at the control room mockup and on-site to evaluate control room components and equipment

(b) an engineering survey to evaluate the control room against guidelines that could be assessed using engineering drawings or that required special studies

(c) an environmental survey to measure control room environmental factors

The applicant's descriptions of the Catawba Unit 1 control room environment, communications equipment, emergency and protective equipment, annunciators, and computer system follow:

(a) Environmental Survey

Gibbs and Hill, Inc. was retained to perform a lighting survey of the Catawba control room. The results of this survey were reviewed by the control room survey team to identify specific HEDs. In general, the lighting was in compliance with recommended guidelines; however, a few minor problems in portions of the control room were identified. HED C-2-153 covers the physical changes necessary to correct the identified problems.

In addition to the survey of control room lighting, surveys of the heating, ventilating, and air conditioning (HVAC) and sound environment in the control room; and the lighting, HVAC, and sound environment for the auxiliary shutdown panel areas were conducted by the control room survey team. Identified HEDs were assessed by the control room review team. The assessment results were that the sound and HVAC environments were in general compliance with recommended guidelines and that no changes were required in these areas, but several changes in the lighting for the auxiliary shutdown area were needed because of glare or low illumination. HED C-1-701 covers the physical changes necessary to correct these problems. Both HEDs C-1-701 and C-2-153 are described in Revision 4 of the Duke Power Response, dated March 28, 1984, to Supplement 1 of NUREG-0737.

(b) Communications Equipment

A recent survey of the communications equipment was performed by the control room survey team. Installed equipment met all recommended guidelines and no HED corrective actions were required. Because of the construction status, the fire brigade radio, NRC red phone, and the NOAA radio were not installed at the time of the survey; they are to be installed before fuel loading. The design documentation for the installation of these items was reviewed and no HEDs were identified.

(c) Emergency Protective Equipment

A recent survey of this equipment was performed by the control room survey team. Adequate fire protection equipment was available and located in designated areas of the control room. No HED corrective actions were required. The location and adequacy of the emergency breathing air system was also reviewed and no HEDs were identified.

(d) Availability and Storage of Reference Materials

This subject was covered in the operating experience review. No problems were identified. In addition, a recent inspection found that the access and storage requirement for procedures, drawings, and other necessary documents met recommended guidelines.

(e) Annunciators

The annunciator system for the control room was reviewed in both the task analysis and control room survey activities. In addition, comments from station operators were received in the operating experience review. A special study of the annunciator system was performed by the control room review team to assess the HEDs identified in these activities in an integrated manner. A solution package was developed that included typical changes such as reengraving of certain windows, rearrangement of certain windows to other panels, and change in wording or abbreviations. These changes are scheduled to be completed under HED C-1-457. This HED is described in the Supplement to Final Report for Catawba Nuclear Station Unit 1, dated May 6, 1983.

(f) Computer

The computer system, including the operator interface with the keyboards, CRTs, and printers, was reviewed in both the task analysis activity and the control room survey activities. In addition this subject was also covered in the operating experience review. HEDs identified during these activities were assessed by the control room review team and those HEDs requiring physical solutions are included in the supplement to Final Report Catawba Nuclear Station Unit 1, dated May 6, 1983. In addition, several HEDs to be resolved by management attention were transmitted to station management. These HEDs concerned the periodic replacement of printer ribbons, contrast of CRTs, alarm buffer increase, and the density of several graphic screens. The staff finds the applicant's responses acceptable.

Initially, the applicant evaluated the NUREG-0700 control room survey guidelines and Duke operating conventions and standards for specific applicability to Catawba Unit 1. Appropriate justification was provided by the applicant for those NUREG-0700 guidelines found to be not applicable to Catawba Unit 1. Then Duke's criteria for the CRS were developed, categorized, and assigned to the three survey activities. The audit team reviewed the guideline selections, categorizations, and assignments and found them appropriate for the plant-specific Catawba Unit 1 CRS. The Catawba 1 CRS identified 308 potential HEDs that were deviations from accepted human factors engineering guidelines.

In summary, it is the staff's judgment that the applicant has met the requirements of conducting a survey to identify deviations from accepted human factors principles.

(5) Assessment of Human Engineering Discrepancies (HEDs) to Determine Which HEDs Are Significant and Should Be Corrected

A total of 523 potential HEDs had been identified in the Catawba Unit 1 control room at the time of the DCRDR preimplementation audit. Duke screened the potential HEDs during the assessment phase of the DCRDR to determine whether:

(a) The potential HED was an actual discrepancy in the site-specific control room context.

(b) The HED required individual study and assessment.

(c) The HED should be resolved to maintain consistency with control room conventions or standards.

(d) The HED was part of a larger or generic HED, or a duplicate HED.

(e) The HED was so minor that no physical change was needed and could be resolved by establishing operator awareness through training.

(f) The HED could be resolved with surface enchancements.

(g) The HED was already being resolved by an existing design change.

Potential HEDs that did not fall into these categories were evaluated by a formal significance evaluation process to determine the relative significance of each HED. Factors of the significance evaluation were the potential for operator error, the potential for detection and recovery, and the consequence of the error to plant operation and safety. The final disposition of potential HEDs and the determination of relative significance were made by an assessment team comprised of three senior reactor operators, three mechanical and nuclear engineers, two electrical engineers, and two human factors specialists. Based on the above process, the applicant designated 210 HEDs for corrective action.

The audit team found the Duke HED assessment process to be a useful, qualitative evaluation tool for comparing HEDs, although the audit team did not consider the process to be sufficiently refined to use the quantitative results as accurate rankings of HED significance.

In summary, it is the staff's judgment that the licensee has met the requirement of assessing HEDs to determine which HEDs are safety significant and should be corrected.

(6) Selection of Design Improvements

Three of Duke's solution teams, each consisting of one operator and one engineer, developed resolutions for the HEDs that Duke determined to be actual discrepancies. The solution teams were assisted by design engineers and human factors specialists. The resolutions considered were physical control room modifications, surface enhancements to control boards, and recommendations for procedures revisions or additional training. Solutions were developed on a control board by control board basis.

Duke also estimated the costs of solutions and, in some cases, alternative solutions. For HEDs that were assigned a relative significance, a significance/cost ratio was determined as an aid to determining cost effectiveness. HEDs without an assigned relative significance were subjectively reviewed for cost effectiveness by Duke's DCRDR review team.

Duke determined that 16 HEDs did not have cost-effective solutions or alternative solutions. These HEDs were identified and documented with justification for no corrective action to be taken. The remainder of the HEDs were designated for corrective action by physical control room changes, by surface enhancement techniques, or by management action for changes in procedures or training. The audit team reviewed the following:

(a) Each of the 16 HEDs that Duke determined did not require corrective action. In all cases, except one, the staff concurred with Duke's justification for no corrective action. The applicant responded that it was his intent to add improved labeling to the switches in this system; however, additions to this system since the HED was identified have required the rearrangement of these switches to accommodate the additional control devices. During this rearrangement the switches were realigned to place train A switches on the left and train B switches on the right. This action fully corrects the original HED. The staff finds the applicant's response acceptable.

(b) Forty-eight of the 210 HEDs that Duke designated for corrective action by physical changes or by surface enhancement techniques. The audit team concurred with Duke's proposed corrective actions for each of these HEDs.

(c) Thirty-one HEDs were referred to management attention. Typical solutions for these HEDs included additional operator training or emphasis; changes to station maintenance procedures; requisition of, or availability of special tools, step ladders, throat microphones, chart paper, etc. Most of these problems were noted as a result of the construction status of the unit and would have been resolved before fuel loading. In addition, two HEDs, which were referred to station management, were identified during the environmental survey. These HEDs concerned the cleaning of control boards and devices and the poor contrast on computer CRTs.

The control room review team transmitted a description of each of these HEDs to station management. Supervision responsible for areas of station management to which the HEDs pertained reviewed the HEDs and proposed appropriate corrective actions to the review team. The review team reviewed the proposed corrective actions for approval before implementation.

Corrective actions for all management-attention HEDs have been completed except for HEDs 276, 486, 519, and 606. The status of these HEDs follows:

HED 276 - Install warning signs in areas prohibited for walkie-talkie use.

Signs have been made for areas that are designated as prohibited for walkie-talkie use. The signs will be installed in designated areas by June 1, 1984.

HED 486 - Backlighted switches on 1.47 panel are hot to touch.

New LED-type bulbs have been ordered as replacements. These bulbs will be installed as soon as they are received.

HED 519 - Frequency of fire detection panel alarms reduces audibility of other control room alarms.

This system has been in test-and-check-out mode. After test completion, volume will be reduced to acceptable level and frequency of alarm occurrences will be low.

HED 606 - Present CRT monitors have poor contrast.

A new type of CRT monitors have been ordered and will be installed by December 1984.

The staff finds the applicant's response acceptable.

Duke prioritized the implementation of HED corrective actions on the basis of (a) the operating status of the plant required for installation of the HED solution, and (b) the significance of the HED.

For scheduling HED corrective action implementation, Duke established two categories of plant operating status: (a) before fuel loading, and (b) by the end of the first refueling outage.

Within each HED correction category, Duke used the HED significance ranking or the subjective significance evaluation of the HED to determine implementation priority and to assign the HEDs to these implementation categories. Scheduling appears to have been a subjective committee deliberation process that was not well documented. Justification for assigning HED corrective actions to the category to be completed after fuel loading and before the end of the first refueling outage was not documented.

A letter from H. B. Tucker (Duke) to H. R. Denton (NRC), dated February 20, 1984, discusses the schedule for specific HED corrective actions to be completed before fuel loading and before the end of the first refueling outage and provides improvements in the original schedule and justifications for HEDs scheduled for completion during these periods.

The staff finds the applicant's response acceptable. However, until the licensee has corrected all human engineering deficiencies according to the schedule contained in the letter of February 20, 1984, this issue will be a License Condition.

(7) <u>Verification That Selected Design Improvements Will Provide the Necessary Corrections</u>

The staff is not sure that the design and installation of the HED solutions by Duke line organization is being followed and documented adequately to verify that the proper corrective action has been implemented. From the documentation reviewed and discussed during the audit, it was not clear how the detailed designs of control room modifications would be checked back against the HED solutions developed by the DCRDR review team to verify that the implemented corrective actions resolve all HEDs.

The applicant responded that HED solutions were developed by the control room review solution teams, which were comprised of instrumentation and control engineers, mechanical/nuclear engineers, senior reactor operators, and a human factors specialist. The recommended solutions were then assigned to the control complex group of the Design Engineering Department for implementation. Two members of the control room review team's "core team" are now assigned to the control complex group. In addition, the remaining personnel of the control complex group served on the control room survey teams and the solution teams during the control room review. These personnel are familiar with both the review and the proposed solutions and are responsible for the implementation of detailed solutions through the nuclear station modification (NSM) process. This process ensures the installation of modifications in accordance with the NSM document package.

The proposed physical changes developed by the control room review solution teams were portrayed on the full-scale control board mockups used for the review. Because HED solutions were integrated on the mockups, the effect of each solution on the Operator as well as its relationship to other solutions, could be observed.

In addition, the Duke Power Emergency Procedure Validation Program provides an administrative process to ensure that a trained operating shift can manage emergency conditions using the plant-specific emergency procedures. This validation process evaluates the adequacy of the operator/procedure/control room interface in handling emergency situations. The program provides both an initial validation and an on-going validation process.

The staff finds the applicant's response acceptable.

(8) <u>Verification That Improvements Will Not Introduce New HEDs</u>

Three of Duke's HED solution teams reviewed the HED solutions on the full-scale, control room mockup and determined that no new HEDs were created by the solutions. The staff concludes that the applicant has met this requirement.

(9) <u>Coordination of Control Room Improvements With Changes From Other Programs Such As SPDS, Operator Training, Reg. Guide 1.97 Instrumentation, and Upgraded Emergency Operating Procedures</u>

Based on audit team findings, the staff concludes that the applicant has met this requirement.

(10) <u>Post-TMI Actions and Salem ATWS Events</u>

The applicant responded that NUREG-0737, Items II.B.1, II.D.3, II.F.1 and II.F.2, resulted in modifications to the displays and controls in the Catawba control room. These TMI items also were incorporated into the emergency procedures as appropriate. As discussed in Duke's response to Supplement 1 to NUREG-0737, operators have been trained on these procedures and the upgraded emergency procedure program will be fully implemented by fuel loading.

Task analyses for inadequate core cooling and for an ATWS event were conducted by the task analysis team during the control room review using Westinghouse Emergency Response Guidelines FR-C.1 and ECA-1. HEDs identified during the task analysis activities were assessed by the review team and the required HED corrective actions are described in the Supplement to Final Report, Catawba Nuclear Station, Unit 1, dated May 6, 1983.

The staff finds the applicant's response acceptable.

18.3 Conclusions

The staff finds that the applicant's DCRDR for Catawba Unit 1 meets all of the requirements of Supplement 1 to NUREG-0737 except for scheduling of HED corrective actions. On the basis of the applicant's responses transmitted by letters dated February 20, and April 9, 1984, the staff concludes, from a human factors standpoint, that a full-power operating license can be granted for Catawba Unit 1.

APPENDIX A

CONTINUATION OF CHRONOLOGY

April 11, 1983	Letter from applicant concerning design of the diesel generator intake and exhaust system.
April 13, 1983	ASLB issues Order extending the time for filing discovery responses.
April 18, 1983	ASLB issues Memorandum and Order regarding rulings on Palmetto Alliance motion to compel discovery from applicant.
April 22, 1983	Letter from applicant concerning resolution of TMI Action Plan Item II.K.3.5., "Automatic Trip of Reactor Coolant Pumps."
April 26, 1983	Letter to applicant concerning their request for withholding information from public disclosure.
April 27, 1983	ASLB issues Memorandum and Order regarding ruling on Palmetto request for remedial measures.
May 6, 1983	Letter to applicant requesting additional information in the hydrologic engineering area.
May 9, 1983	Generic Letter 83-20 -- Integrated Scheduling for Implementation of Plant Modifications.
May 10, 1983	Letter from applicant forwarding storage and in-transit security plan for special nuclear material (SNM) of low strategic significance.
May 11, 1983	Generic Letter 83-21 -- Clarification of Access Control Procedures for Law Enforcement Visits.
May 13, 1983	Letter to applicant forwarding Supplement 1 to the Safety Evaluation Report.
May 13, 1983	ASLB issues Memorandum and Order regarding ruling on applicant's motion to compel discovery from Palmetto Alliance.
May 16, 1983	Letter from applicant concerning open items, confirmatory items, and license conditions.
May 18, 1983	Letter from applicant concerning proposed steam generator modifications.
May 20, 1983	Letter from applicant forwarding proposed Unit 1 Technical Specifications.

May 25, 1983	Meeting with applicant to discuss Type C leak rate testing of certain isolation valves.
May 27, 1983	Letter from applicant concerning pressurizer safety valve sizing and LOCA sensitivity analysis.
May 31, 1983	Letter to applicant concerning control of heavy loads, NUREG-0612.
June 1, 1983	Letter from applicant concerning internal corrosion protection for the fuel oil storage tanks.
June 3, 1983	Generic Letter 83-22 -- Safety Evaluation of Emergency Response Guidelines.
June 7, 1983	Letter from applicant concerning containment systems branch confirmatory items.
June 7, 1983	Letter from applicant concerning removal of the key-locked switches from the control room HVAC circuits.
June 13, 1983	ASLB issues Memorandum and Order regarding ruling on Palmetto Alliance motion for further discovery.
June 15, 1983	Letter from applicant forwarding 1982 Annual Reports.
June 20, 1983	ASLB issues Memorandum and Order regarding ruling on applicant and staff motion for sanctions.
June 20, 1983	Letter from applicant forwarding Revision 4 to Security Plan.
June 20, 1983	Letter from applicant forwarding electrical elementary diagrams.
June 21, 1983	Letter from applicant responding to questions in the hydrologic engineering area.
June 22, 1983	Letter from applicant forwarding public information brochure for the station.
June 28, 1983	Letter from applicant concerning control of heavy loads.
June 28, 1983	Letter to applicant concerning issuance of operating license amendments to McGuire Nuclear Station.
June 29, 1983	Letter from applicant concerning control room access.
June 30, 1983	Commission issues Memorandum and Order CLI-83-19 regarding criteria for accepting late filed contentions based on information contained in licensing-related documents that are not required to be prepared early enough in a licensing proceeding to provide a timely basis for framing contentions.

July 5, 1983	Generic Letter 83-26 -- Clarification of Surveillance Requirements for Diesel Fuel Impurity Level Tests.
July 6, 1983	Generic Letter 83-27 -- Surveillance Intervals in Standard Technical Specifications.
July 8, 1983	Generic Letter 83-28 -- Required Actions Based on Generic Implications of Salem ATWS Events.
July 8, 1983	Letter from applicant concerning containment pressure control system.
July 11, 1983	Letter from applicant concerning flooding of electrical equipment as a result of a LOCA.
July 14, 1983	ASLB issues Memorandum and Order approving stipulation between applicants and Charlotte-Mecklenburg Environmental Coalition regarding the latter's withdrawal as a party.
July 14, 1983	Letter from applicant concerning lockout of manual control by the load sequencer.
July 14, 1983	Letter from applicant concerning 100% load rejection capability.
July 20, 1983	Letter from applicant concerning difficulty with purchase orders that involve 10 CFR 21.
July 20, 1983	ASLB issues Memorandum and Order regarding schedule leading to hearing. Hearing scheduled to begin October 4, 1983.
July 21, 1983	Generic Letter 83-30 -- Deletion of Standard Technical Specification Surveillance Requirement 4.8.1.1.2.d.6 for Diesel Generator Testing.
July 25, 1983	Letter from applicant concerning standby shutdown system.
July 26, 1983	Letter from applicant concerning ESF grade containment purge filter system design (Confirmatory Item 41).
July 26, 1983	Letter from applicant concerning loose parts monitoring systems (Confirmatory Item 9).
July 26, 1983	Letter from applicant concerning emergency planning and related meteorology.
July 27-28, 1983	Meeting and tour by Caseload Forecast Panel to assess construction completion schedule (summary issued August 22, 1983).
July 29, 1983	Letter from Model D2/D3 steam generator design review panel notifying that its work has been completed and that panel should be dissolved.

August 1, 1983	Letter from applicant forwarding electrical diagrams.
August 2, 1983	Letter to applicant concerning detailed control room design review - Supplement 1, NUREG-0737 (McGuire and Catawba Nuclear Stations).
August 8, 1983	Letter from applicant concerning plans for modification of the Unit 1 steam generators.
August 9-12, 1983	Preimplementation audit of detailed control room design review summary report at site.
August 17, 1983	ASLB issues Order concerning miscellaneous matters.
August 18, 1983	Letter to applicant concerning emergency operations facilities review.
August 19, 1983	Letter to applicant requesting additional information in the hydrologic engineering area.
August 26, 1983	ASLB issues Memorandum and Order ruling on applicant's motion for partial summary disposition of Contention 6.
August 29, 1983	Letter to applicant concerning Duke proposal to undertake Nelson Electric duties Under 10 CFR 21.
August 30, 1983	Letter to applicant concerning results of NRC caseload forecast panel visit July 27-28, 1983.
September 1, 1983	ASLB issues Order confirming time and place for prehearing conference, time for presentation of Palmetto's further discovery requests, and rulings on two disputed documents. Final prehearing conference scheduled on September 12, 1983, at 9:30 a.m. in Mecklenburg County Courthouse.
September 6, 1983	Letter from applicant requesting an extension of time for responding to Generic Letter 83-28.
September 6, 1983	ASLB issues Memorandum and Order ruling on applicant and staff motions for summary disposition of Contentions 16 and 19 and on Palmetto motion for sanctions.
September 8, 1983	ASLB issues Memorandum and Order ruling on summary disposition motion concerning Contention 18/44.
September 13, 1983	Board Notification 83-140 -- Summary Board Notification.
September 13, 1983	Meeting with applicant to visit site and observe the D3 steam generator modification for Unit 1 (summary issued October 4, 1983).
September 13-14, 1983	Meeting with applicant to visit site and discuss open and confirmatory items related to the power systems branch review.

September 14, 1983	ASLB issues Order concerning prehearing conference.
September 15, 1983	Meeting with applicant to discuss the internal corrosion protection for fuel oil storage tanks and the emergency lighting.
September 20, 1983	ASLB issues Order denying motion by Palmetto Alliance for extension of time in which to file objections to the Board's September 14 prehearing conference order.
September 21, 1983	Board Notification 83-139 -- Westinghouse Reactor Coolant Pump Seals.
September 26, 1983	Letter from applicant forwarding Revision 2 to the response to Supplement 1 to NUREG-0737.
September 28, 1983	Letter from applicant concerning (License Condition 20) loss of primary source of condensate storage water.
September 29, 1983	Board Notification 83-66A -- Westinghouse Rod Drop Issue.
September 29, 1983	ASLB issues Memorandum and Order ruling on remaining emergency planning contentions.
September 29, 1983	Board Notification 82-105A -- NRC staff evaluation regarding allegations of potential design deficiencies in Class I piping.
September 30, 1983	Meeting with applicant to discuss the internal corrosion protection for fuel oil storage tanks and the emergency lighting (summary issued November 25, 1983).
September 30, 1983	ASLB issues Notice of Reconstitution of Board. Board now consists of J. Kelley, Chairman, and R. Foster and P. Purdom.
September 30, 1983	ASLB issues Memorandum and Order ruling on objections to prehearing conference order.
October 4, 1983	Board Notification 83-151 -- Westinghouse ECCS Actuation Logic.
October 13, 1983	Letter from applicant correcting incorrect statements in trip report.
October 13, 1983	Letter from applicant concerning test of engineered safeguards P-4 interlock.
October 13, 1983	Letter from applicant concerning performance of the standby nuclear service water pond.
October 13, 1983	Letter from applicant concerning loss of both RHR trains resulting from a single instrument bus failure.

October 17, 1983	Board Notification 83-140A -- Transmits copy of BN 83-128 concerning draft test report on qualification test program of Class 1E solenoid valves.
October 18, 1983	ASLB issues Memorandum and Order ruling on applicant's and staff's motions for summary disposition of DES Contention 17.
October 19, 1983	Generic Letter 83-33 -- NRC Positions on Certain Requirements of Appendix R to 10 CFR 50.
October 19, 1983	Letter from applicant concerning instrumentation of inadequate core cooling detection.
October 21, 1983	Board Notification 83-160 -- New Information Concerning Transamerica Delaval (TDI) Emergency Diesel Generators.
October 25, 1983	Board Notification 83-147 -- New Information - Apparent Deficiency Related to Diesel Generators.
October 26, 1983	Letter to applicant concerning clarification of required actions based on generic implications of Salem ATWS events.
October 26, 1983	Letter from applicant responding to SER open items.
October 26, 1983	Letter from applicant concerning relief and safety valve testing.
October 31, 1983	Meeting with applicant to discuss technical issues related to probable maximum precipitation and its effects on safety-related structures and components.
October 31, 1983	Generic Letter 83-38 -- NUREG-0965, "NRC Inventory of Dams."
October 31, 1983	Letter to applicant concerning local flooding and site drainage.
November 1, 1983	ASLB issues Protective Order.
November 1, 1983	Board Notification 83-175 -- QA/QC Investigations at Catawba.
November 1-4, 1983	Meeting with applicant and site visit to audit fire protection program.
November 2, 1983	Generic Letter 83-35 -- Clarification of TMI Action Plan Item II.K.3.31.
November 2, 1983	Board Notification 83-163 -- New Information - Apparent Deficiency Related to a Reactor Coolant Pump.
November 7, 1983	Letter from applicant forwarding revisions to Crisis Management Plan Implementing Procedures.

November 11, 1983	Letter from applicant concerning emergency lighting and internal corrosion protection for fuel oil storage tanks.
November 15, 1983	ASLAB issues Order concerning ASLB's November 1 protective order.
November 17, 1983	Board Notification 83-160A -- Supplemental Information Concerning Transamerica Delaval (TDI) Emergency Diesel Generators.
November 17, 1983	Commission issues Order concerning ASLB and ASLAB Orders dated November 10 and 14, respectively.
November 18, 1983	Letter from applicant concerning leak-before-break concept.
November 21, 1983	Letter to applicant concerning control of heavy loads, Phase II, NUREG-0612.
December 2, 1983	Generic Letter 83-32 -- NRC Staff Recommendations Regarding Operator Action for Reactor Trip and ATWS.
December 6, 1983	Commission issues Order concerning ASLB and ASLAB orders dated November 10 and 14, respectively.
December 7, 1983	Letter to applicant concerning request for additional information on Transamerica Delaval diesel generators.
December 19, 1983	Generic Letter 83-42 -- Clarification to Generic Letter 81-07 Regarding Response to NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."
December 19, 1983	Generic Letter 83-43 -- Reporting Requirements of 10 CFR Part 50, Sections 50.72 and 50.73, and Standard Technical Specifications.
December 20, 1983	Generic Letter 83-44 -- Availability of NUREG-1021, "Operator Licensing Examiner Standards."
December 20, 1983	Letter from licensee concerning potential benefits of eliminating postulated pipe breaks in the reactor coolant system primary loop.
December 21, 1983	Generic Letter 83-40 -- Operator Licensing Examination.
December 21, 1983	Letter from applicant forwarding facility staffing survey.
December 30, 1983	ASLB issues Memorandum and Order confirming closing of the record and schedule for filing proposed findings.
December 30, 1983	ASLB issues Memorandum and Order denying applicant's motion for reconsideration concerning revised emergency planning, Contention 11.

December 30, 1983	Letter to applicant requesting additional information regarding Transamerica Delavel emergency diesel generators.
January 5, 1984	Generic Letter 84-01 -- NRC Use of the Terms, "Important to Safety" and "Safety Related."
January 5, 1984	Board Notification 84-04 -- Environmental Qualification Briefing of Chairman by Sandia.
January 6, 1984	Generic Letter 84-02 -- Notice of Meeting Regarding Facility Staffing.
January 10, 1984	Letter from applicant forwarding offsite dose calculation manual.
January 13, 1984	ASLB issues Memorandum and Order setting time and place for evidentiary hearing.
January 13, 1984	Generic Letter 84-03 -- Availability of NUREG-0933, "A Prioritization of Generic Safety Issues."
January 13, 1984	Letter from applicant concerning proposal to undertake Nelson Electric duties under 10 CFR 21.
January 17, 1984	Letter from applicant concerning 100% load reduction capability.
January 17, 1984	Letter from applicant concerning fire protection site audit.
January 18, 1984	Board Notification 84-11 -- NRC Use of the Terms, "Important to Safety" and "Safety Related."
January 19, 1984	Letter from applicant concerning emergency planning and related meteorology.
January 20, 1984	Letter to applicant forwarding comments on the public information brochure and transmitting the fire protection site audit summary.
January 20, 1984	ASLB issues Order postponing evidentiary hearing. Hearing is postponed until January 30-31, 1984, in Charlotte, North Carolina.
January 24, 1984	Letter from applicant concerning proposed license condition regarding shift technical advisor.
January 24, 1984	Board Notification 84-13 -- TDI response to NRC questions concerning Transamerica Delaval emergency diesel generators.
January 26, 1984	Letter from applicant forwarding Amendment 30 to application for operating licenses.

January 30, 1984	Letter from applicant forwarding Revision 3 to response to Supplement 1 to NUREG-0737.
January 30, 1984	ASLAB issues Memorandum and Order denying Palmetto Alliance's motion for directed certification of a December 13 oral ruling of the Licensing Board.
February 1, 1984	Letter from applicant concerning core exit thermocouples.
February 1, 1984	Letter from applicant concerning Hydrologic Engineering Branch question related to Confirmatory Item 1.
February 1, 1984	Generic Letter 84-04 -- Safety Evaluation of Westinghouse Topical Reports Dealing with Elimination of Postulated Pipe Breaks in PWR Primary Main Loops.
February 1, 1984	Letter from applicant concerning steam generator level control and protection.
February 2, 1984	Letter from applicant concerning the fire protection system in the diesel room.
February 3, 1984	Letter from applicant concerning relief and safety valve testing.
February 7, 1984	Letter from applicant concerning postaccident sampling system.
February 7, 1984	Letter from applicant concerning flooding of electrical equipment as a result of a LOCA.
February 7, 1984	Meeting with applicant to discuss arbitrary intermediate breaks.
February 7, 1984	Letter from applicant concerning environmental qualification of equipment.
February 7, 1984	Letter from applicant concerning implementation schedule for human engineering discrepancies solutions to be completed by the end of the first refueling outage.
February 8, 1984	Letter from applicant concerning Environmental Qualification Program.
February 8, 1984	Meeting with applicant to discuss environmental qualification of equipment (summary issued March 27, 1984).
February 9, 1984	Meeting with applicant to discuss the environmental qualification of D.G. O'Brien penetrations (summary issued February 22, 1984).
February 9, 1984	Board Notification 84-06 -- Falsification of Quality Control Documents Relating to the Construction of Safety-Related HVAC Units by the Bahnson Co., Winston Salem, North Carolina.

February 10, 1984	Letter from applicant concerning Fire Protection Site Audit Summary.
February 10, 1984	Letter from applicant concerning the operator training program.
February 13, 1984	Board Notification 84-20 -- Report of Meeting of Representatives of the Transamerica Delaval, Inc. (TDI) Emergency Diesel Generators Owners' Group.
February 13, 1984	Board Notification 84-21 -- Staff Inspection Reports of Transamerica Delaval, Inc., for Inspections Conducted from 3/79 to 7/83.
February 13, 1984	Board Notification 84-32 -- Additional Information on Environmental Qualification.
February 14, 1984	ASLAB issues Memorandum and Order denying applicant's request for interlocutory review of the admission of a revised version of their Contention 11.
February 15, 1984	Letter from applicant concerning elimination of arbitrary intermediate pipe breaks.
February 15, 1984	Letter from applicant concerning secondary water chemistry monitoring and control program.
February 16, 1984	Board Notification 84-33 -- Task Action Plan for USI A-17 "Systems Interaction Program."
February 20, 1984	Letter from applicant concerning proposed modification of Westinghouse Model D4/D5/E steam generators.
February 20, 1984	Letter from applicant concerning control room design review.
February 20, 1984	Letter from applicant concerning reactor coolant pump motor oil collection system of the fire protection program.
February 20, 1984	Letter from applicant concerning vital area/equipment identification.
February 21, 1984	ASLB issues Memorandum and Order concerning motion to bifurcate operating license proceeding.
February 22, 1984	Letter from applicant responding to questions regarding the Transamerica Delaval, Inc. diesel generators.
February 23, 1984	ASLAB issues Order concerning intervenors' three-part contention on reliability of the facility's diesel generators.
February 23, 1984	ASLB issues Memorandum and Order referring certain diesel generator issues to the Appeal Board.

February 27, 1984	ASLBP issues Order establishing new ASLB to preside over all emergency planning issues. The Board is comprised of M. Margulies, Chairman, R. Lazo, and F. Hooper.
February 27, 1984	ASLB issues Memorandum and Order admitting a Board contention concerning certain diesel generator problems.
February 27, 1984	Board Notification 84-38 -- Status Update Westinghouse ECCS Actuation Logic.
February 28, 1984	New ASLB issues Memorandum and Order concerning scheduling of hearing on emergency planning.
February 28, 1984	Board Notification 84-39 -- Report of meetings between the NRC and representatives of the Transamerica Delaval, Inc (TDI) Emergency Diesel Generators Owners Group.
February 28, 1984	Letter from applicant transmitting the equipment lists for the Seismic Qualification Review Team and Pump and Valve Operability Review Team onsite audits.
February 29, 1984	Letter from applicant concerning the fire protection site audit.
February 29, 1984	Board Notification 84-44 -- Transamerica Delaval, Inc. (TDI) 10 CFR Part 21 Report on Turbocharger Thrust Bearing Lubrication Deficiency.
February 29, 1984	Board Notification 84-31 -- Allegations Regarding Quality Assurance Program on Catawba Nuclear Power Plant.
February 29, 1984	Letter from applicant concerning technical feasibility and potential benefits of eliminating postulated pipe breaks in the pressurizer surge lines from the structural design basis.
February 29, 1984	Letter from applicant forwarding Revision 10 to report "An Analysis of Hydrogen Control Measures at McGuire Nuclear Station."
March 1, 1984	ASLAB issues Order granting staff's motion for an extension of time to submit its views with respect to the ASLB's February 23 referral order.
March 1, 1984	Letter from applicant concerning elimination of arbitrary intermediate pipe breaks.
March 6-8, 1984	Meeting and site visit with applicant to audit the equipment environmental qualification.
March 7, 1984	Letter from applicant deleting references to three-loop operation from the Proof and Review Technical Specifications.
March 7, 1984	Board Notification 84-47 -- Transamerica Delaval, Inc. Owners Group Piston Skirt Report and Task Descriptions.

March 8, 1984	Letter from applicant concerning location of welded attachments.
March 9, 1984	Letter to applicant transmitting a preliminary draft SER for the detailed control room design review.
March 12, 1984	Board Notification 84-52 -- Meeting Summaries Containing Transcripts of February 10 and 16, 1984, Meetings Between NRC and Transamerica Delaval, Inc. Owners Group.
March 12, 1984	Letter from applicant concerning qualification documentation for the containment purge and vent valves.
March 12, 1984	Board Notification 84-51 -- Transamerica Delaval, Inc. Diesel Generators Owners Group Program Plan.
March 13, 1984	Letter from applicant concerning performance of the SNSW pond.
March 13, 1984	Meeting with applicant to conduct the confirmatory site visit.
March 14, 1984	Letter from applicant forwarding summary of the experience for the Operations personnel to be licensed on Unit 1.
March 15, 1984	Letter from applicant concerning the proposed snubber Technical Specifications.
March 15, 1984	Letter from applicant concerning changes to surveillance requirements for diesel fuel oil in the Proof and Review Technical Specifications.
March 16, 1984	ASLB issues Memorandum and Order denying motion to defer action on diesel generator contentions.
March 19, 1984	Meeting with applicant to discuss resolution of the main steamline break analysis.
March 20, 1984	Letter from applicant concerning proposed amendments to the Proof and Review Technical Specifications.
March 21, 1984	Letter from applicant concerning test exemptions for Proof and Review Technical Specifications.
March 21, 1984	Meeting with applicant to discuss a plan of action for the resolution of concerns related to the TDI diesel generators (summary issued April 11, 1984).
March 22, 1984	Letter from applicant concerning changes to the Proof and Review Technical Specifications.
March 23, 1984	Letter from applicant concerning SER Open Item 15, Emergency Lighting.
March 23, 1984	Board Notification 84-63 -- Reports Submitted by the Transamerica Delaval, Inc. Owners Group.

March 26, 1984	Letter from applicant concerning TMI Action Plan Item II.K.3.5, "Automatic Trip of Reactor Coolant Pumps."
March 28, 1984	Letter from applicant concerning main steamline break using a revised heat transfer model.
March 28, 1984	Letter from applicant concerning Proof and Review Technical Specifications.
March 29, 1984	Letter from applicant forwarding City of Charlotte Emergency Plan.
March 30, 1984	Letter from applicant forwarding relief requests concerning Preservice Inspection Program.
April 2, 1984	Generic Letter 84-05 -- Change to NUREG-1021, "Operator Licensing Examiner Standards."
April 2, 1984	Letter to applicant forwarding safety evaluation related to elimination of arbitrary intermediate pipe breaks.
April 2, 1984	ASLB issues Adjudicatory Hearing Schedule on Emergency Planning Contentions. Hearing will commence on May 1, 1984.
April 2, 1984	Board Notification 84-57 -- Equipment Temperature Response in Ice Condenser Containment.
April 4, 1984	Generic Letter 84-08 -- Interim Procedures for NRC Management of Plant-Specific Backfitting.
April 4, 1984	Letter from applicant proposing changes to the Proof and Review Technical Specifications.
April 4, 1984	Board Notification 84-72 -- TDI Owners Group/NRC Meeting Transcript and Additional TDI Owners Group Information Submitted.
April 5, 1984	Letter from applicant concerning justification for not testing certain isolation valves.
April 5, 1984	Letter from applicant concerning extended operation tests and the inspection plans for the 1A and 1B diesel generators.
April 9, 1984	Letter from applicant concerning power lockout to motor-operated valves.
April 9, 1984	Letter from applicant concerning the detailed control room design review.
April 10, 1984	Letter to applicant requesting additional information concerning leak-before-break analysis.

April 10, 1984	Letter to applicant requesting additional information related to procedures and systems review, offsite dose calculation manual, improved thermal design procedure, and emergency preparedness.
April 11, 1984	Letter from applicant concerning Pump and Valve Operability Review Team audit.
April 11, 1984	Letter from applicant proposing changes to the Proof and Review Technical Specifications.
April 11, 1984	Letter from applicant concerning the fire protection preliminary draft safety evaluation report.
April 11, 1984	Letter from applicant concerning installation of circuit modification before fuel load.
April 13, 1984	Letter from applicant concerning his public information brochure.
April 13, 1984	ASLB issues Order dismissing intervenor's crankshaft contention.
April 16, 1984	Letter from applicant concerning environmental qualification of mechanical equipment.
April 16, 1984	Letter from applicant concerning thermal design procedures and flow measurement techniques.
April 16, 1984	Letter from applicant concerning preservice inspection program.
April 16, 1984	ASLB issues Notice of Hearing. Hearing on Emergency Planning contentions will commence at 9:30 a.m. in the Old Post Office Building, Rock Hill, South Carolina, on May 1, 1984
April 16, 1984	Letter from applicant forwarding revision to Security Plan.
April 16, 1984	Letter from applicant forwarding revision to Contingency Plan.
April 17, 1984	ASLAB issues Memorandum and Order dismissing ASLB's February 27, 1984, referral of a ruling rejecting two segments of a three-part untimely contention by intervenors Palmetto Alliance and the Carolina Environmental Study Group.
April 18, 1984	Letter from applicant concerning Seismic Qualification Review Team audit.
April 18, 1984	Letter from applicant concerning load sequencer accelerated sequence.
April 19, 1984	Letter from applicant concerning control of heavy loads.
April 19, 1984	Board Notification 84-76 -- Westinghouse Reactor Coolant Pump Seals.

April 19-20, 1984	Meeting with applicant to discuss the proof and review comments on Unit 1 Technical Specifications.
April 24, 1984	Letter from applicant forwarding Amendment 31 to application for operating licenses.
April 24, 1984	Letter from applicant concerning ECCS flow measurements and NPSH verification.
April 25, 1984	Letter from applicant concerning Fire Protection Program.
April 25, 1984	Letter from applicant concerning compliance with IE Bulletin 80-06.
April 26, 1984	Generic Letter 84-10 -- Administration of Operating Tests Prior to Initial Criticality (10 CFR 55.25).
April 30, 1984	Generic Letter 84-12 -- Compliance with 10 CFR 61 and implementation of the Radiological Effluent Technical Specifications (RETS) and Attendant Process Control Program (PCP).
April 30, 1984	Meeting with applicant to discuss ice sublimation shielding material.
May 3, 1984	Generic Letter 84-13 -- Technical Specifications for snubbers.
May 4, 1984	Letter from applicant concerning comments on proof and review of Technical Specifications.
May 4, 1984	Letter from applicant forwarding changes to proof and review of Technical Specifications.
May 7, 1984	Board Notification 84-98 -- Additional Reports Submitted to NRC by TDI Owners Group.
May 8, 1984	Letter to applicant requesting additional information concerning hydrogen control and financial qualifications.
May 10, 1984	Letter from applicant concerning alarm in the control room for boron dilution modes in all modes of operations.
May 11, 1984	Letter from applicant concerning postaccident sampling system.
May 11, 1984	Letter from applicant concerning lifting devices.
May 11, 1984	Letter from applicant concerning disposal procedure for radioactively contaminated material
May 11, 1984	Letter from applicant concerning leak-before-break concept.

May 14, 1984	Letter from applicant concerning TMI Item II.F.2, "Instrumentation for Inadequate Core Cooling."
May 17, 1984	Board Notification 84-97 -- Supplement to the Information Provided in Board Notification 83-147 (dated October 25, 1983) Related to Metal Files in Diesel Generators.
May 18, 1984	Meeting with applicant to discuss Reactor Systems Branch related to Unit 1 Technical Specifications.
May 21, 1984	Meeting with applicant to discuss resolution of issues related to the review of equipment seismic qualification.
May 22, 1984	Meeting with applicant to discuss resolution of issues related to the review of equipment seismic qualification.
May 22, 1984	Letter from applicant forwarding Revision 11 to report, "An Analysis of Hydrogen Control Measures at McGuire Nuclear Station."
May 23, 1984	Letter from applicant responding to questions from the Procedures and Systems Review Branch.
May 23, 1984	Letter from applicant concerning Fracture Prevention of Containment Pressure Boundary.
May 25, 1984	Letter to applicant concerning Unit 1 Technical Specifications.
May 25, 1984	Letter to applicant concerning steam generator tube rupture events and requesting additional information. Also requests information on financial qualification.
May 29, 1984	Letter from applicant concerning clarifications to the Control Room Design Review Task Analysis.
May 29, 1984	Letter from applicant concerning leak-before-break concept.
May 29, 1983	Letter from applicant concerning offsite dose calculation manual.
May 30, 1984	Letter to applicant concerning review of utility on-shift operating experience.
May 30, 1984	ASLB issues Memorandum and Order (Authorizing Issuance of a License to Load Fuel and Conduct Certain Precritical Testing).
May 31, 1984	Letter from applicant concerning seismic qualification of equipment.
May 31, 1984	Letter from applicant concerning internal corrosion protection for fuel oil storage tanks.

May 31, 1984	Letter from applicant concerning load reduction capability.
June 1, 1984	Letter from applicant concerning proposed program for resolution of the TDI diesel generator issue.
June 1, 1984	Letter from applicant forwarding Revision 4 to the Emergency Plan.
June 1, 1984	Letter from applicant concerning draft Technical Specification on snubbers.
June 5, 1984	Letter from applicant concerning blackout and load rejection test.
June 8, 1984	Commission issues Order for ASLB to terminate its consideration of the TDI diesel generator contention.

APPENDIX B

BIBLIOGRAPHY

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

U.S. Department of the Army, Office of the Chief of Engineers EM 1110-2-1411, Civil Engineering Bulletin No. 52-8, "Standard Project Flood Determinations," Washington, D.C., March 1952 (reprinted June 1964).

U.S. National Oceanic and Atmospheric Administration and Corps of Engineers, Hydrometeorological Report (HMR) No. 51, "Probable Maximum Precipitation Estimates, United States East of the 105th Meridian," June 1978.

U.S. National Weather Service, HMR No. 52, "Application of Probable Maximum Precipitation Estimates - United States East of the 105th Meridian," August 1982.

U.S. Nuclear Regulatory Commission, NUREG-0422, "Safety Evaluation Report Related to the Operation of McGuire Nuclear Station, Units 1 and 2, May 1983.

---, NUREG-0966, "Safety Evaluation Report Related to the D2/D3 Steam Generator Modification," March 1983.

---, NUREG/CR-2136, "Effect of Postulated Event Devices on Normal Operation of Piping Systems in Nuclear Power Plants," May 1981.

U.S. Weather Bureau, HMR No. 33, "Seasonal Variation of the Probable Maximum Precipitation East of the 105th Meridian for Area from 10 to 1000 Square Miles and Durations of 6, 12, 24, and 48 hours," April 1956.

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

---, "RVLIS - Summary Report," December 1980.

---, "Environmental Qualification of Class IE Motors for Nuclear Out of Containment Use," March 1976.

APPENDIX D

PRINCIPAL CONTRIBUTORS

NRC STAFF

Name	Title	Branch
R. Gonzales	Hydraulic Engineer	Environmental and Hydrologic Engineering
R. McMullen	Geologist	Geosciences
R. Kirkwood	Principal Mechanical Engineer	Mechanical Engineering
J. Rajan	Senior Mechanical Engineer	Mechanical Engineering
G. Hammer	Mechanical Engineer	Mechanical Engineering
D. Terao	Mechanical Engineer	Mechanical Engineering
N. Chokshi	Structural Engineer	Structural and Geotechnical Engineering
M. Hum	Senior Materials Engineer	Materials Engineering
D. Sellers	Senior Materials Engineer	Materials Engineering
A. Lee	Senior Mechanical Engineer	Equipment Qualifications
H. Walker	Materials Engineer	Equipment Qualifications
J. Jackson	Mechanical Engineer	Equipment Qualifications
J. Wing	Senior Chemical Engineer	Chemical Engineering
B. Turovlin	Materials Engineer	Chemical Engineering
D. Kubicki	Fire Protection Engineer	Chemical Engineering
A. Singh	Mechanical Engineer (Aux. Sys.)	Auxiliary Systems
F. Burrows	Reactor Engineer (Instrumentation)	Instrumentation and Control Systems
J. Lazevnick	Electrical Engineer (Reactor Systems)	Power Systems
R. Giardina	Mechanical Engineer (Reactor Systems)	Power Systems
S. Diab	Nuclear Engineer	Reactor Systems
J. Pulsipher	Containment Systems Engineer	Containment Systems
R. Palla	Containment Systems Engineer	Containment Systems
H. Richings	Senior Reactor Physicist	Core Performance
Y. Hsii	Nuclear Engineer	Core Performance

Name	Title	Branch
T. Huang	Nuclear Engineer	Core Performance
M. Dunenfeld	Senior Reactor Engineer	Core Performance
F. Allenspach	Nuclear Engineer (Management Systems)	License Qualifications
F. Liederbach	Principal Operational Safety Engineer	Procedures and Systems Review
J. Kramer	Senior Human Factors Engineer	Human Factors Engineering
G. Simonds	Emergency Preparedness Analyst	Emergency Preparedness
E. Chow	Reliability & Risk Analyst	Reliability and Risk Assessment
F. Jape	Chief, Test Programs Section, Division of Engineering and Operational Programs	Region II

NRC CONTRACTORS

Brookhaven National Laboratory

Gage, Babcock, and Associates, Inc.

Idaho National Engineering Laboratories

NRC FORM 335 (2-84) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

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1. REPORT NUMBER (Assigned by TIDC, add Vol. No., if any)

NUREG-0954
Supplement No. 2

2. TITLE AND SUBTITLE

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

3. LEAVE BLANK

4. DATE REPORT COMPLETED

MONTH	YEAR
June	1984

5. AUTHOR(S)

6. DATE REPORT ISSUED

MONTH	YEAR
June	1984

7. 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

8. PROJECT/TASK/WORK UNIT NUMBER

9. FIN OR GRANT NUMBER

10. SPONSORING ORGANIZATION NAME AND MAILING ADDRESS (Include Zip Code)

Same as 7 above

11a. TYPE OF REPORT

Safety Evaluation Report, Supplement 2

b. PERIOD COVERED (Inclusive dates)

12. SUPPLEMENTARY NOTES

Pertains to Docket Nos. 50-413 and 50-414

13. ABSTRACT (200 words or less)

This report supplements the Safety Evaluation Report (NUREG-0954) issued in February 1983 and Supplement 1 issued in April 1983 by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission with respect to the application filed by Duke Power Company, North Carolina Municipal Power Agency Number 1, North Carolina Membership Corporation, and Saluda River Electric Cooperative, Inc., as applicants and owners, for licenses to operate the Catawba Nuclear Station, Units 1 and 2 (Docket Nos. 50-413 and 50-414, respectively). The facility is located in York County, South Carolina, approximately 9.6 km (6 mi) north of Rock Hill and adjacent to Lake Wylie. This supplement provides more recent information regarding resolution or updating of some of the open and confirmatory issues and license conditions identified in the Safety Evaluation Report.

14. DOCUMENT ANALYSIS – a. KEYWORDS/DESCRIPTORS

b. IDENTIFIERS/OPEN-ENDED TERMS

15. AVAILABILITY STATEMENT

Unlimited

16. SECURITY CLASSIFICATION

(This page)
Unclassified

(This report)
Unclassified

17. NUMBER OF PAGES

18. PRICE

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

OFFICIAL BUSINESS
PENALTY FOR PRIVATE USE, $300

FIRST CLASS MAIL
POSTAGE & FEES PAID
USNRC
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PERMIT No. G67

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US NRC
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