NUREG-0781
Supplement No. 2

Safety Evaluation Report
related to the operation of South Texas Project, Units 1 and 2

Docket Nos. 50-498 and 50-499

Houston Lighting and Power Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 1987

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ABSTRACT

In April 1986 the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0781) regarding the application of Houston Lighting and Power Company (applicant and agent for the owners) for a license to operate South Texas Project, Units 1 and 2 (Docket Nos. 50-498 and 50-499). The facility is located in Matagorda County, Texas, west of the Colorado River, 8 miles north-northwest of the town of Matagorda and about 89 miles southwest of Houston. The first supplement to NUREG-0781 was issued in September 1986. This second supplement reports on the status of unresolved items in the Safety Evaluation Report and identifies certain additional items that have since been reviewed by the staff.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

In April 1986 the Nuclear Regulatory Commission (NRC) staff issued its Safety Evaluation Report (SER) (NUREG-0781) on the application filed by Houston Lighting and Power Company (HL&P), the applicant, acting on behalf of itself and the other owners [City Public Service Board of San Antonio (CPS), Central Power and Light Company (CPL), and City of Austin (COA)] for a license to operate South Texas Project, Units 1 and 2, Docket Nos. 50-498 and 50-499. At that time the staff identified items that had not been resolved with the applicant. In the first supplement to the SER (SSER 1) published in September 1986, the status of unresolved items and the comments made by the Advisory Committee on Reactor Safeguards (ACRS) in its letter dated June 10, 1986, were presented. This second supplement reports on the status of the unresolved items, indicates those which have been resolved, and identifies certain additional items which the staff is either reviewing or has reviewed.

Each of the following sections or appendices is numbered the same as the corresponding SER section or appendix that is being supplemented. Each section is supplementary to and not in lieu of the discussion in the SER unless otherwise noted. Appendix A continues the chronology of the staff's actions related to the processing of the South Texas Project application. Appendix B lists references cited in this report.* Appendix D contains abbreviations used in this supplement. Appendix E lists principal staff members and consultants who contributed to this supplement. Appendix P is the staff evaluation of the Westinghouse report, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems." Appendix Q is a Technical Evaluation Report on inservice testing, and Appendix R is a Technical Evaluation Report on emergency response capability (Regulatory Guide 1.97). Appendix S is the audit report published by the staff after the fourth and final audit of the verification and validation program of the qualified display processing system. Appendices T and U are respectively Technical Evaluation Reports on Items 2.1.2 and 4.5.2 of Generic Letter 83-28.

Copies of this SER supplement are available for inspection at the NRC Public Document Room at 1717 H Street, N.W., Washington, D.C., and at the local Public Document Room located at the Wharton Junior College Library, Wharton, Texas.

The NRC Project Manager for South Texas Project, Units 1 and 2, is N. Prasad Kadambi. Dr. Kadambi may be contacted by calling (301) 492-7272 or by writing to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

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

1.7 Open Items

The staff identified certain open items in the SER listed in Table 1.4 that was updated in SSER 1. The section number of the discussion is shown for reference. Table 1.4 keeps a running tally of the list so that the number shown increases with new items even as items are resolved as shown in the status column. Two items have been resolved in SSER 2 and two have been converted to confirmatory items. One item on pipe break criteria has been added to reflect a range of issues being considered as described in Section 3.6.2. Progress has been made for resolution of the equipment qualification item through completion of the audits on seismic and dynamic qualification and pump and valve operability on December 18, 1987. The tabulation shows 11 items remain to be resolved, with resolution of 7 of the items expected in the next supplement to the SER.

1.8 Confirmatory Items

The staff identified confirmatory items in the SER indicating additional information or review needed to confirm preliminary conclusions. The listing was shown in Table 1.5 and was updated in SSER 1. It is also a running tally. Ten items have been resolved in this supplement (SSER 2), and ten additional items (Nos. 36 through 45) have been added to the list. A breakdown of the added items indicates that Nos. 36 and 41 are relief requests; No. 37 was created by the ACRS; Nos. 38, 39, and 40 take account of upcoming audits; No. 42 formalizes a conclusion reached earlier; and No. 43 was created by a new Generic Letter 86-16, "Westinghouse ECCS Evaluation Models." Numbers 44 and 45 were taken from the open items list. The tabulation shows 29 items remain to be resolved, with the resolution of 15 items expected in the next supplement to the SER.

1.9 License Conditions

In Section 1.9 of the SER, the staff identified three license conditions. These are issues that must be resolved by the applicant as a condition for issuance of an operating license to ensure that NRC requirements are met during plant operation.

The current status of license conditions is listed in the updated version of Table 1.6. The item on qualification of the residual heat removal system has been resolved through a commitment made by the applicant in a submittal dated September 30, 1986, that the system would be qualified to withstand postaccident conditions. No new license conditions have been added at this time.

Table 1.4 Listing of open items

Item		Status	SER Section
(1)	Internal flooding analysis	Under review	3.4.1, 9.2.7, 9.3.3
(2)	Internal missiles analysis	Resolved in SSER 1	3.5.1, 10.4.9
(3)	Staff review of jet impingement from high energy pipe failures	Resolved in SSER 1	3.6.1
(4)	Equipment qualification		
	(a) Seismic and dynamic qual.	Under review	3.10.1
	(b) Pump and valve operability	Under review	3.10.2
	(c) Environmental equipment qual.	Under review	3.11.3
(5)	Preservice inspection/inservice inspection program review	Under review, status in SSER 2	5.2.4, 6.6.1
(6)	Design, verification, and validation of qualified display processing system	Under review, status in SSER 2	7.1.2
(7)	Acceptability of isolation between safety and non-safety systems	Awaiting information	7.3.2.5
(8)	Conformance to RG 1.97	Resolved in SSER 2	7.5.2.4
(9)	Test results of aluminum-sheathed and copper-sheathed cable	Awaiting information	8.3.3.3
(10)	Maximum available fault currents at electrical penetrations	Resolved in SSER 1	8.3.3.5
(11)	Safe and alternate shutdown systems	Resolved in SSER 2	9.5.1
(12)	Auxiliary feedwater system reliability study	Resolved in SSER 1	10.4.9
(13)	Emergency planning	Under review	13.3
(14)	Industrial security	Under review	13.6
(15)	Analysis for boron dilution event during modes 4 and 5	Awaiting information	15.4.6
(16)	Use of TREAT code for small-break loss-of-coolant-accident analysis	Under review, status in SSER 2	15.6.5, 6.3.5

Table 1.4 (Continued)

Item	Status	SER Section
(17) Review of submittals on Generic Letter 83-28	Converted to Confirmatory Item 44	15.8.2
(18) Wear of the bottom mounted instrumentation thimbles	Converted to Confirmatory Item 45	3.9.2.3
(19) Pipe break criteria	Awaiting information, under review, status in SSER 2	3.6.2

Table 1.5 Listing of confirmatory items

Item		Status	SER Section
(1)	Onsite meteorological measurements program (a) Comparison of new with old system (b) Measurements of precipitation to resolve anomalous and inconsistent records	Awaiting information	2.3.3
(2)	Staff's independent analysis of the thermal performance of the essential cooling pond	Resolved in SSER 1	2.4.11.2
(3)	Geotechnical monitoring program to detect horizontal and vertical movements	Resolved in SSER 1	2.5.1
(4)	Review of stability and safety data relative to main cooling reservoir dike after filling to 49 feet msl	Awaiting information, status in SSER 2	2.5.7
(5)	Completion of review of reports on pressure relief devices	Awaiting information	3.9.3.2
(6)	Design information on ASME Code Class 1, 2, and 3 component supports (Question 210.60)	Awaiting information	3.9.3.3
(7)	Preservice and inservice testing of pumps and valves	Resolved in SSER 2	3.9.6
(8)	Acceptability of consequences from momentary liftoff of fuel assembly	Resolved in SSER 1	4.2.3.1(9)
(9)	Combined seismic and loss-of-coolant-accident loads on fuel assemblies	Resolved in SSER 2	4.2.3.3(4)
(10)	Steam generator inspection	Under review	5.4.2.2.2
(11)	Applicability of Diablo Canyon natural circulation test	Under review	5.4.7
(12)	Conservatism of loss-of-coolant-accident analysis in light of information in FSAR Table 6.3.1 and response to Question 440.39	Resolved in SSER 1	6.3.1

Table 1.5 (Continued)

Item		Status	SER Section
(13)	Analysis for nonisolable small-break loss-of-coolant accident	Combined with Open Item 16	6.3.5.2
(14)	Reanalysis of loss-of-coolant accident during shutdown	Combined with Confirmatory Item 15	6.3.5.3
(15)	Analyses for 6-inch and 8-inch breaks with justification for operator actions	Awaiting information	6.3.6, 15.6.5
(16)	Interface between Class 1E and circuits	Awaiting information	7.3.2.12
(17)	Adequacy of design change so that main steam isolation valves do not operate on safety injection signal	Under review	7.3.2.2
(18)	Additional information on Criterion 2 of NUREG-0737 Item II.B.3	Resolved in SSER 2	9.3.2.2
(19)	Procedures for preventive maintenance and operability checks on emergency communication equipment	Awaiting information	9.5.2.5
(20)	Inservice inspection and testing of emergency dc lighting	Under review	9.5.3
(21)	Revision of radwaste process control program to meet staff guidelines	Awaiting information	11.4.2
(22)	Update process and instrumentation diagrams for solid waste processing	Awaiting information	11.4.2
(23)	Report on staff's site visit to corporate office and plant	Under review	13.1.1.3
(24)	Conformance to Generic Letter 84-16 on hot operating experience	Under review	13.1.2.1
(25)	Compliance with commitments on administrative procedures	Under review	13.5.1.9

Table 1.5 (Continued)

Item		Status	SER Section
(26)	Qualification requirements for preoperational and initial startup test personnel to be equivalent to American National Standards Institute/American Nuclear Society Standard 3.1-1981	Resolved in SSER 1	13.5.1.9
(27)	Staff review of the procedures generation package	Under review	13.5.2
(28)	Plant-specific information on steam generator tube rupture	Under review	15.6.3
(29)	Review of design against 10 CFR 50.62	Resolved in SSER 2	15.8.1
(30)	Results of the engineering assurance program	Awaiting information	17.4.3
(31)	Results of the final verification and validation program for the final emergency operating procedures	Under review	18
(32)	Results of investigation of green Roto-tellite lights under actual operating conditions	Under review	18
(33)	Results of surveys of lighting, sound, meter, and communication system when control room work is completed	Under review	18
(34)	NUREG-0737 items:		
	II.E.1.1 Auxiliary feedwater system evaluation	Combined with Open Item 12	10.4.9
	II.E.3.1 Emergency power for pressurizer heaters	Resolved in SSER 1	8.3.6
	II.G.1 Power supplies for pressurizer relief valves, block valves, and level indicators	Resolved in SSER 1	8.3.6
	II.K.1 IE Bulletins 5. Review of ESF Valves 10. Operability Status	 Resolved in SSER 1 Resolved in SSER 1	6.3.1

Table 1.5 (Continued)

Item			Status	SER Section
(34)	NUREG-0737 items: (cont'd)			
	II.K.2	Orders B&W plants 13. Thermal mechanical report: effect of HPI for small-break LOCA with no auxiliary feedwater	Resolved in SSER 1	15.6.5
	II.K.3	Final recommendations, B&O task force		
		3. Reporting SV and RV failures and challenges	Resolved in SSER 1	5.2.2.1
		5. Automatic trip of RCPs	Combined with Confirmatory Item 35	15.6.5.1
		17. ECCS outages	Resolved in SSER 1	6.3.1
		25. Power on pump seals	Resolved in SSER 1	15.1.15.1
		30. Small-break LOCA methods	Under review	15.6.5
		31. Compliance with 10 CFR 50.46	Under review	15.6.5
	III.A.1.2	Upgrading of emergency support facilities	Combined with Open Item 13	13.3
	III.A.2	Emergency preparedness	Combined with Open Item 13	13.3
	III.D.1.1	Primary coolant outside containment	Resolved in SSER 2 with a condition	13.5
(35)	Compliance with Generic Letter 85-12 (TMI Item II.K.3.5) RCP setpoint for small-break LOCAs		Under review	15.6.5.1
(36)	Safety-Related Instrument Tubing Program		Resolved in SSER 2	3.9.3
(37)	DG Fuel Oil Piping Vibration Test Plan		Resolved in SSER 2	3.9.2.1
(38)	Electrical, instrumentation and control systems audits		Under review	7.1, 8.1
(39)	SPDS audit		Under review	
(40)	Fire Protection Program audit		Under review	

Table 1.5 (Continued)

Item	Status	SER Section	
(41)	Deletion of the containment spray system sump additive tank	Resolved in SSER 2 Generic issue under review	6.5.2
(42)	RTD bypass loop elimination	Resolved in SSER 2	4.4.3.2
(43)	Revision to the BART code	Under review	6.3.5
(44)	Compliance with GL 83-28	Resolved in SSER 2 Items under review do not impact licensing	15.8.2
(45)	BMI thimble vibration	Awaiting information	

Table 1.6 Listing of license conditions

Item		Status	SER Section
(1)	Implementation report on preoperational testing of the reactor vessel water level system	Awaiting information	4.4.6.3
(2)	Postaccident qualification of the residual heat removal system before December 31, 1988, or the second refueling outage, whichever comes first	Resolved through commitment made September 20, 1986	5.4.7.7
(3)	Implementation and maintenance in effect of all provisions of the approved fire protection program	Awaiting information	9.5.1.8

2 SITE CHARACTERISTICS

2.5 Geology and Seismology

2.5.7 Reevaluation of Completed Main Cooling Reservoir

To satisfy the provisions of Regulatory Guide (RG) 1.59, "Design Basis Floods for Nuclear Power Plants," the applicant postulated a nonmechanistic breach of the main cooling reservoir (MCR) embankment to determine the design-basis flood level. Section 2.4.10 of the SER discusses this postulated breach and resulting flood protection measures. Revision 2 of RG 1.59, issued after the South Texas construction permit was docketed, suggested that an evaluation of the effects of erosion and scour caused by a breach of reservoir embankments should be included in the evaluation of the design-basis flood. Rather than making an assessment of the effects of scour, the applicant chose to make an evaluation of the integrity of the MCR embankment facing the safety-related plant structures. This alternate approach was accepted by the staff in the SER. As indicated in Section 2.4.10 of the SER, a failure of the north side of the MCR embankment produces the design-basis flood for all safety-related structures. The staff deferred judgment on the MCR embankment because the initial filling of the reservoir to the operational level of 49 feet msl (mean sea level) and the period immediately following filling are most critical to the stability and integrity of the MCR embankment.

The applicant designed a program of controlled reservoir filling to develop an understanding of the embankment underseepage control system. This program consisted of filling the reservoir to elevation 35 feet msl, monitoring the embankment instrumentation, and visually observing the embankment performance. At 35 feet msl the effects on the underseepage control system resulting from changes in annual groundwater level are minimized.

By letter dated September 29, 1986 (M. R. Wisenberg, HL&P, to V. S. Noonan, NRC), the applicant submitted a report that described the embankment underseepage control system response resulting from the filling of the reservoir to elevation 35 feet msl. In addition, the report identified remedial work necessary to improve the safety of the MCR embankment at operating pool levels.

Small boils and seepage were detected in the plant area drainage ditch invert. This area is inspected daily by the applicant, and the detected boils are not actively piping material from the foundation. The applicant's consultant has recommended that a filtered seepage exit should be constructed in this location before resuming to fill the reservoir. The installation of adequately designed filtered seepage exits is an acceptable method of preventing the piping of material from the foundation of embankments.

With the reservoir at 35 feet msl, the calculated uplift factor of safety of the embankment toe, based on observed piezometer levels, was less than 1.5 for several reaches of the embankment. The applicant's consultant has recommended that additional relief wells be designed and installed to limit the uplift factors of safety to a minimum of 1.5 for projected uplift pressures at reservoir elevation 49 feet msl. A factor of safety of 1.5 against uplift is necessary to ensure the long-term stability of the embankment. Section 2.5.6.4.2 of the SER indicated that the installation of additional relief wells, increasing the size of the exterior berm, or increasing the size of the toe ditch were acceptable methods of increasing the factor of safety against uplift should the observed conditions warrant it.

Maintenance around the MCR collector ditches had suffered before the reservoir was filled to an elevation of 35 feet msl. High grasses, cattails, and water standing in areas of ditches where the invert had lowered because of erosion created a condition in which inspection of these areas was difficult. Although maintenance in the collector ditches has improved, the applicant should commit to continue maintenance to ensure inspectability of the collector ditches. The collector ditch inverts should be restored to design elevations.

On the basis of information provided by the applicant, the staff concludes that the MCR embankment in the vicinity of plant structures is capable of containing the reservoir up to an elevation of 35 feet msl. Before filling of the reservoir to the operational level of 49 feet msl, the remedial work identified above should be completed. The pool elevation should not exceed 35 feet msl before completion of the remedial work. The remedial work is necessary to ensure safety of the MCR embankment under all operating conditions. The applicant's program of MCR instrument monitoring, embankment inspection, and maintenance should continue. The favorable evaluation of the MCR to date is conditional on completion of the remedial work and continued instrument monitoring before exceeding 35 feet msl.

The staff's final judgment of the MCR must await the results of the applicant's remedial work. The applicant must report to the staff the results of the remedial work and the performance of the MCR embankment underseepage control system with the reservoir at elevation 49 feet msl. The staff will report the results of its evaluation in a future supplement to the SER. This remains a confirmatory item.

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

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

The staff stated in the SER that the review in accordance with SRP Section 3.6.2 (NUREG-0800) pertains to the methodology used for protecting safety-related structures, systems, and components against the effects of postulated pipe breaks both inside and outside containment. The staff has used the review procedures identified in SRP Section 3.6.2 to evaluate the effect that breaks in high-energy fluid systems would have on adjacent safety-related structures, systems, or components with respect to jet impingement and pipe whip. The staff also reviewed the location, size, and orientation of postulated failures and the methodology used to calculate the resulting pipe whip and jet impingement loads that might affect nearby safety-related structures, systems, or components.

After the staff prepared the SER, the applicant provided submittals to the staff that, if approved, would grant additional relief in certain pipe break postulation and analysis criteria. The submittals are in the following areas:

(1) an increase in the value of the minimum acceptable cumulative usage factor (CUF) from 0.1 to 0.4

(2) additional locations where arbitrary intermediate breaks need not be postulated

(3) methods for performing piping analyses, such as coupling a main run of piping with a branch line, and the increased seismic damping factors

(4) use of leak-before-break technology beyond the locations specifically approved by the Commission's completed rulemaking (see 51 FR 12502)

The staff has not completed the reviews in all of these areas and there are areas of overlap between them. Discussions are continuing with the applicant, with recent requests for additional information and justification. This is an open item and has been added to the tabulation in Table 1.4.

3.6.2.1 Elimination of Large Primary Loop Ruptures as a Design Basis

By letter dated September 28, 1983, the applicant submitted a Westinghouse report (Westinghouse Report MT-SME-3078) on the technical bases for eliminating large primary loop piping ruptures as a structural design basis. This submittal was made in support of a request for an exemption from General Design Criterion (GDC) 4 of Appendix A to 10 CFR 50 in regard to the need for protection against dynamic effects from postulated pipe breaks. After meeting with the applicant and Westinghouse, the NRC staff formally responded by letter dated April 20, 1984, to transmit the staff's comments and questions on the submittal. The response to the staff's concerns resulted in a revision to the report (WCAP-10559), submitted to the NRC on July 17, 1984. By means of deterministic fracture mechanics analyses, the applicant contends that postulated double-ended guillotine breaks of the primary loop reactor coolant piping will not occur in South Texas Project, Units 1 and 2, and therefore need not be considered as a design basis for installing protective devices, such as pipe whip restraints and jet impingement shields, to guard against the dynamic effects associated with such postulated breaks. No other changes in design requirements are addressed within the scope of the referenced reports; for example, no changes to the definition of a loss-of-coolant accident or its relationship to the regulations addressing design requirements for the emergency core cooling system (10 CFR 50.46), containment (GDC 16 and 50), other engineered safety features, and the conditions for environmental qualification of equipment (10 CFR 50.49).

On April 11, 1986, a final rule was published (51 FR 12502), effective May 12, 1986, amending 10 CFR 50, Appendix A, GDC 4. The revised GDC 4 allows the use of analyses to eliminate from the design basis the dynamic effects of postulated pipe ruptures of primary coolant loop piping in pressurized water reactors. In the summary section of the final rule, it is stated that the new technology reflects an engineering advance that simultaneously allows an increase in safety, reduced worker radiation exposures, and lower construction and maintenance costs. Implementation permits the removal of pipe whip restraints and jet impingement barriers as well as other related changes in operating plants, plants under construction, and future plant designs. Containment design, emergency core cooling, and environmental qualification requirements are not influenced by this modification. In the supplementary information section of the final rule, it is stated that acceptable technical procedures and criteria are defined in NUREG-1061, Volume 3, dated November 1984, entitled "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks."

With the revised GDC 4, the exemption originally requested is no longer necessary. Using the criteria in NUREG-1061, Volume 3, the staff has reviewed and evaluated the applicant's submittals, and the following provides the staff's findings.

Parameters Evaluated by the Staff

The primary coolant system of South Texas Units 1 and 2, described in WCAP-10559, has four main loops, each comprising a 33.9-inch-diameter hot leg, a 36.2-inch-diameter crossover leg, and a 31.14-inch-diameter cold-leg piping. The material in the primary loop piping is cast stainless steel (SA 351 CF8A). In its review of WCAP-10559, the staff evaluated the Westinghouse analyses with regard to compliances with Chapter 5.0 of NUREG-1061, Volume 3. The staff criteria follow:

(1) The loading conditions should include the static forces and moments (pressure, deadweight, and thermal expansion) resulting from normal operation, and the forces and moments associated with the safe shutdown earthquake (SSE). These forces and moments should be located where the highest stresses, coincident with the poorest material properties, are induced for base materials, weldments, and safe-ends.

(2) For the piping run/systems under evaluation, all pertinent information should be provided to demonstrate that degradation or failure of the piping resulting from stress corrosion cracking, fatigue, or waterhammer are not likely. Relevant operating history should be cited, which includes system operational procedures, system or component modification, water chemistry parameters, limits and controls, resistance of material to various forms of stress corrosion, and performance under cyclic loadings.

(3) A throughwall crack should be postulated at the highest stressed locations determined from item (1) above. The size of the crack should be large enough so that leakage detection is ensured with at least a factor of 10, using the minimum installed leak detection capability when the pipe is subjected to normal operational loads.

(4) It should be demonstrated that the postulated leakage crack is stable under normal plus SSE loads for long periods of time (i.e., crack growth, if any, is minimal during an earthquake). The margin, in terms of applied loads, should be at least 1.4 and should be determined by a crack stability analysis (i.e., the leakage-size crack will not experience unstable crack growth even if large loads (larger than design loads) are applied). This analysis should demonstrate that crack growth is stable and the final crack size is limited, so that a double-ended pipe break will not occur.

(5) The crack size should be determined by comparing the leakage-size crack to the critical-size crack. Under normal loads plus SSE loads, it should be demonstrated that there is a margin of at least 2 between the leakage-size crack and the critical-size crack to account for the uncertainties inherent in the analyses and leakage detection capability. A limit-load analysis may suffice for this purpose; however, an elastic-plastic fracture mechanics (tearing instability) analysis is preferable.

(6) The materials data provided should include types of materials and materials specifications used for base metal, weldments, and safe-ends; materials properties including the J-R curve used in the analyses; and long-term effects such as thermal aging and other limitations to valid data (e.g., J maximum, maximum crack growth).

The margins cited in the staff criteria are guidelines. Their applicability is dependent on the conservatism of the analyses performed.

Conclusions

On the basis of its evaluation of the analysis contained in WCAP-10559, the staff finds that the applicant has presented an acceptable technical justification, addressing the above criteria, for not installing protective devices to deal with the dynamic effects of large pipe ruptures in the main loop primary coolant system piping of South Texas Units 1 and 2. This finding is predicated on the fact that each of the parameters evaluated for South Texas is enveloped by the generic analysis performed by Westinghouse in WCAP-9558, and accepted by the staff in Enclosure 1 to Generic Letter 84-04. Specifically:

(1) The loads associated with the highest stressed location in the main loop primary system piping are 1,958 kips (axial), 24,505 in.-kips (bending

moment) and result in maximum stresses less than the bounding stresses used by Westinghouse in WCAP-9558, or those established by the staff as limits (e.g., a moment of 42,000 in.-kips in Enclosure 1 to Generic Letter 84-04).

(2) For Westinghouse plants, there is no history of cracking failure in reactor primary coolant system loop piping. The Westinghouse reactor coolant system primary loop has an operating history that demonstrates its inherent stability. This includes a low susceptibility to cracking failure from the effects of corrosion (e.g., intergranular stress corrosion cracking), waterhammer, or fatigue (low and high cycle). This operating history totals over 400 reactor-years, including 5 plants each having 15 years of operation and 15 other plants with over 10 years of operation.

(3) The leak rate calculations performed for South Texas using an initial throughwall crack of 7.5 inches are identical to those of Enclosure 1 to Generic Letter 84-04. South Texas Units 1 and 2 have a reactor coolant system (RCS) pressure boundary leak detection system that is consistent with the guidelines of Regulatory Guide 1.45, and it can detect leakage of 1 gpm in 1 hour. The calculated leak rate through the postulated flaw results in a factor of at least 10 relative to the sensitivity of the South Texas plant leak detection system.

(4) The margin in terms of load based on fracture mechanics analyses for the leakage-size crack under normal plus SSE loads is within the bounds calculated by the staff in Section 4.2.3 of Enclosure 1 to Generic Letter 84-04. Based on a limit-load analysis, the load margin is about 2.8; based on the J limit discussed in item (6) below, the margin is at least 1.4.

(5) The margin between the leakage-size crack and the critical-size crack was calculated by a limit-load analysis. Again, the results demonstrated that a margin of at least 3 on crack size exists and is within the bounds of Section 4.2.3 of Enclosure 1 to Generic Letter 84-04.

(6) As an integral part of its review, the staff's evaluation of the material properties data of WCAP-10456 is enclosed as Appendix P to this supplement. In WCAP-10456, data for 10 plants, including the South Texas units, are presented, and lower bound or worst-case materials properties were identified and used in the analysis performed in WCAP-10559. The applied J for South Texas in WCAP-10559 was less than 3000 in.-lb/in.^{2}, and hence the staff's upper bound on the applied J (see Appendix P, page 4) was not exceeded.

In view of the analytical results presented in WCAP-10559 and the staff's evaluation findings related above, the staff concludes that the probability or likelihood of large pipe breaks occurring in the primary coolant system loop of South Texas Units 1 and 2 is sufficiently low that protective devices associated with postulated pipe breaks at the eight locations per loop in the South Texas Units 1 and 2 primary coolant system (as specified in the applicant's letter of July 17, 1984) need not be installed. Furthermore, the staff concludes that the applicant is in compliance with GDC 4, as revised.

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components, and Equipment

3.9.2.1 Piping Preoperational Vibration and Dynamic Effects Testing

In the SER, the staff reported on its evaluation of the South Texas Units 1 and 2 piping preoperational vibration and dynamics effects testing program. Part of the basis for that evaluation was a response to staff question Q 210.41, which provided a list of the specific systems to be tested by the applicant. One of these systems was the diesel generator system. In a letter dated June 10, 1986 D. Ward, ACRS, to N. Palladino, NRC), the Advisory Committee on Reactor Safeguards (ACRS) recommended that the applicant perform tests and take appropriate corrective measures to prevent possible failures caused by vibration in the diesel generator fuel oil piping. This request was transmitted to the applicant in a letter dated June 13, 1986. In a letter dated June 27, 1986, the applicant agreed to respond to this request by August 1986. In letters dated August 29 and December 1, 1986, the applicant provided "Test Guidelines for Vibration Testing of Diesel Generator Fuel Oil Supply Lines for South Texas, Unit 1." The December 1, 1986, letter contains Revision 1 of the test guideline that provides a description of the vibration acceptance criteria that will be used during the testing of the subject piping. These criteria are consistent with those previously reported by the staff in Section 3.9.2.1 of the SER. The criteria are also consistent with applicable sections of the May 1985 draft of ANSI/ASME Standard OM-3, "Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems." The staff has been closely involved in the development of this standard and is in agreement with the criteria therein.

In the letter dated August 29, 1986, the applicant stated that since the layout of the diesel generators and associated fuel oil piping is the same for South Texas Units 1 and 2, the results of the testing and any required modifications on Unit 1 will also be applicable to Unit 2. Therefore, a separate testing program will not be performed on Unit 2. The staff does not agree that similarity in piping design and layout between units of any nuclear power plant provides the basis for not performing preoperational testing on all units of a plant. One of the primary objectives of this testing is to discover possible deficiencies in fabrication, installation, and inspection, as well as design, before licensing of each unit. For example, similarities in design and layout between Units 1 and 2 do not provide assurance that supports are properly installed and snubbers (if applicable) are functional in Unit 2 without testing Unit 2. Therefore, the staff will require that the applicant commit to performing preoperational vibration and dynamics effects testing on the diesel generator fuel oil piping on Unit 2. With the exception of the vibration acceptance criteria to which the applicant has committed, the testing program for Unit 2 does not necessarily have to be identical to that for Unit 1.

On the basis of the above discussion, the staff has concluded that "Test Guidelines for Vibration Testing of Diesel Generator Fuel Oil Supply Lines for South Texas, Unit 1" is acceptable, and a commitment to perform tests on Unit 2 as described above is sought. However, the item is considered closed for the licensing schedule of Unit 1.

3.9.2.3 Preoperational Flow-Induced Vibration Testing of Reactor Internals

In SSER 1, the staff addressed the issue of wear in the bottom-mounted instrument (BMI) thimbles based on the applicant's letter of June 27, 1986. Subsequently, the applicant has submitted additional information by letter dated December 19, 1986, which provides details relative to the design changes which will be implemented on South Texas Units 1 and 2 to prevent wear on the BMI thimbles similar to that experienced at several European plants. In the December 19th letter, the applicant also stated that a study performed by Westinghouse and the applicant has concluded that the BMI thimble wear is a vibration problem resulting from high flow velocity in the BMI column gap. The applicant proposes to reduce this velocity in the 14-foot core at South Texas Units 1 and 2 so that the velocity is similar in magnitude to that in the 12-foot core plants. To accomplish this, Westinghouse has designed a flow-limiting device that will be installed just above the lower core support plate between the fuel assembly and the support plate. Similar devices are currently in use in several European 14-foot core plants.

Because of design differences between Units 1 and 2 relative to the size of the existing gap between the outside diameter of the thimble and the inside diameter of the BMI column, Unit 1 will require a sleeve around the thimble in addition to the flow-limiting device. This sleeve will result in a gap size in Unit 1 identical to that of Unit 2. The applicant submitted detailed sketches of these proposed changes in its letter dated December 19, 1986.

The staff has reviewed the additional information and has concluded that the design changes proposed by the applicant provide reasonable assurance that the wear problem on South Texas Units 1 and 2 will not occur. Because similar design changes have already been implemented on European 14-foot core plants and because the applicant has committed to monitor the performance of these plants relative to this issue, the staff has concluded that this should be a confirmatory issue pending documentation of conclusive data verifying that the BMI thimble wear has been minimized on these 14-foot core plants.

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

The staff has reviewed the relief request contained in letters dated August 13, 1986 and October 16, 1986, which present a description of the applicant's program for design, fabrication, installation, testing, and inspection of safety-related instrument tubing for South Texas Units 1 and 2. This program applies to Safety Class 2 and 3 (Quality Group B and C) instrument lines that are located downstream of the socket weld at the root valve up to and including the last valve at the instrument. The root valve is the isolation valve that separates the instrument tubing from the process line. The tubing used is stainless steel 3/8 inch or less in diameter. Compression fittings have been used for instrument tubing connections in lieu of welded attachments. The adequacy of tubing connections will be ensured by installation of compression fittings in accordance with the manufacturer's recommended practice, followed by 100 percent pressure testing of all fittings in accordance with American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) requirements. In addition, 100 percent visual inspection of fittings during and after the pressure test will be performed and documented in the Pressure Test Report.

The applicant has presented a detailed comparison of the program with ASME Code requirements. All items in the program are seismic Category I, and are designed, fabricated, installed, and tested using ASME Code, Section III, as guidance. These items are subject to the applicant's project quality assurance program in accordance with 10 CFR 50, Appendix B. As part of the above comparison, the applicant has stated that the inservice inspection required by ASME Code, Section XI, is not applicable to its program. The staff position on this part of the proposed program, is that, as a minimum, the subject tubing should be tested and examined in accordance with the requirements of ASME Code, Section XI, articles IWA-5000 (with the exception of IWA-5300, "Test Reports"), IWC-5000, and IWD-5000.

On the basis of the above discussion and the information in the letters of August 13 and October 16, 1986, the staff has concluded that the applicant's program for design, fabrication, installation, testing and inspection of safety-related instrument tubing for South Texas Units 1 and 2 provides a quality level that is commensurate with that of the attached ASME Code, Section III fluid system and is acceptable pending a commitment that all tubing segments which include the compression fittings are subject to the applicable requirements of ASME Code, Section XI, articles IWA-5000 (with the exception of IWA-5300), IWC-5000 and IWD-5000.

3.9.6 Inservice Testing of Pumps and Valves

10 CFR 50.55a, "Codes and Standards," requires, in part, that certain safety-related pumps and valves meet the requirements of Section XI of the ASME Code. To meet the requirements of this regulation, the applicant has submitted its first 10-year inservice testing (IST) program on pumps and valves for South Texas Unit 1. Since the review started, revision to the IST program was made by the applicant. The staff has reviewed Revision 1 of the applicant's IST program dated August 12, 1986, and the results of the review are provided below. It should be noted that any additional requests for relief submitted by the applicant after August 12, 1986, should not be implemented by the applicant before NRC review and approval.

The NRC consultant, EG&G Idaho, Inc., has reviewed the August 12, 1986, submittal of the applicant's IST program, and prepared an evaluation of the applicant's IST program for South Texas Unit 1 (see Appendix Q). The staff has reviewed the evaluation and concurs in its bases and findings.

On the basis of its review of EG&G's Technical Evaluation Report (TER) regarding the IST program for South Texas, the staff concludes that the applicant's IST program dated August 12, 1986, and associated request for relief from certain specific requirements of Section XI of the ASME Code are acceptable with the exceptions discussed below and identified in Appendix D of Appendix Q. The applicant must resolve these exceptions in accordance with the conclusions discussed below and the guidelines presented in Appendix Q. These exceptions and associated staff comments are provided as follows:

(1) The applicant has requested to test the residual heat removal pumps quarterly during plant operation and measure all parameters with the exception of pump inlet pressure and differential pressure (see Section 2.2.1 of Appendix Q). The staff concurs that since there will be very little variation in pump inlet pressure and as the applicant is

utilizing pump outlet pressure to determine pump hydraulic condition, this should be sufficient testing during power operation. However, the applicant should measure all Code-required parameters during cold shutdowns.

(2) The applicant has requested relief from exercising valves FCV-0551, 0552, 0553, and 0554, feedwater regulator valves (see Section 3.3.1.1 of Appendix Q), in accordance with the requirements of Section XI, paragraphs IWV-3412 and 3414, and proposed to verify valve operability by partial-stroke exercising of these valves during plant operation on a nonspecified frequency and full-stroke exercising of these valves on a cold shutdown frequency. The staff concurs with the applicant that these valves can only be full-stroke exercised during cold shutdown. However, the staff concludes that the applicant should perform partial-stroke exercising of these valves at least quarterly during power operation.

(3) The applicant has requested relief from the corrective action requirements of Section XI, paragraph IWV-3417(a) for all degraded valves that require stroke timing at increased frequency and can only be exercised during cold shutdowns (see Section 3.6.1.2 of Appendix Q). The staff concludes that continued plant operation should not be permitted when these valves are known to be operating in a degraded condition. These valves should be replaced before startup from cold shutdown.

4 REACTOR

4.2 Fuel Design

4.2.3 Design Evaluation

4.2.3.3 Fuel Coolability Evaluation

(4) Structural Damage From External Forces

In the SER, the staff stated that fuel assembly structural damage from external forces is a confirmatory issue that requires the applicant to submit the results of a combined seismic and loss-of-coolant-accident (LOCA) loading analysis for the fuel assemblies.

By a letter dated September 12, 1986 (M. R. Wisenburg, HL&P, to V. S. Noonan, NRC), the applicant provided the results of a combined seismic and LOCA loading analysis using the approved methods described in WCAP-9401. The results show that the combined loads on grids and non-grid components are less than the allowable loads for South Texas Units 1 and 2.

The staff concludes that the applicant has demonstrated acceptable results for fuel assemblies under combined seismic and LOCA conditions. Thus, Confirmatory Item 9 is resolved.

4.4 Thermal-Hydraulic Design

4.4.3 Design Abnormalities

4.4.3.2 Crud Deposition and Flow Uncertainty

By letter dated August 2, 1985 (M. R. Wisenburg, HL&P, to G. W. Knighton, NRC), the applicant indicated that the reactor coolant temperature measurement system for the hot legs will be modified. This modification is to eliminate the resistance temperature device (RTD) bypass manifold in order to reduce radiation exposure, improve availability, and reduce maintenance. However, the new hot-leg temperature method has the disadvantage of a slightly longer response time.

The new method of measuring hot-leg temperatures uses RTDs in thermowells. These are located in each hot leg at three locations (120° apart) where there were formerly sampling scoops. The new method, with a thermowell RTD, measures the temperature at one point rather than the five sample holes used at the same location for scoop measurement. The RTD is placed at the same radial location as the center hole of the scoop and therefore measures the equivalent of the average scoop sample if a linear radial temperature gradient exists in the pipe.

A microprocessor-based system is used to perform the averaging of the reactor coolant hot-leg signals from the three RTDs in each hot leg and then to transmit the signal for the average hot-leg temperature to protection and control systems. This system is called a qualified display processing system (QDPS) and is discussed in Final Safety Analysis Report (FSAR) Section 7.2.2.3. The QDPS has a routine for performing a quality check of the three temperature signals for each hot leg. Because of hot-leg temperature streaming, there is a variation in temperature in the cross-section of the hot legs. The three locations in each hot leg are used to get an average value of the variation. The QDPS has the capability to add a bias to the averaging calculation, if needed, in order to compensate for the loss of one of the three RTD sensor inputs. The bias considers the past history of the previous hot-leg readings. It is noted that cold-leg temperature streaming is not a problem because of the mixing action of the reactor coolant pump. The applicant has stated that the measurement of the cold-leg temperature has also been modified with a single thermowell RTD and spare in each cold leg in place of a scoop with external reading.

By letter dated October 16, 1986 (M. R. Wisenberg, HL&P, to V. S. Noonan, NRC), the applicant provided FSAR changes regarding the new reactor coolant system (RCS) temperature measurement system modifications required because of the elimination of the RTD bypass loop. Included were the results of the reanalysis of several FSAR Chapter 15 non-LOCA accidents. The staff questioned the applicant regarding the accuracy and response time effects on the new temperature measurement system. Besides the effect of the accuracy of the hot-leg temperature in the accident analysis, it is the principal contributor in the analysis for calculating the RCS flow measurement uncertainty. The longer response time has an effect on the results of the accident analysis.

In a letter dated November 24, 1986 (M. R. Wisenberg, HL&P, to V. S. Noonan, NRC), the applicant responded to the staff's questions and stated that the accuracy of the hot-leg temperature will be included in the RCS flow measurement uncertainty analysis to be submitted later. The new method of measuring hot-leg temperatures with thermowell RTDs, used in place of the three scoops, has been analyzed to be slightly more accurate than the RTD bypass system, since the error caused by imbalances in the scoop sample flows is eliminated. Although the thermowell measurement may have a small error relative to the scoop measurement because of a temperature gradient over the 5-inch scoop span, this gradient has been calculated to have a small effect. Therefore, it is concluded that the three thermowells will provide a more accurate measurement than the three scoops.

The overall response time of the new South Texas thermowell RTD hot-leg temperature system is 0.5 sec longer than the former RTD bypass system (6.5 vs 6.0 sec). The applicant stated that the increased channel response time results in longer delays from the time when fluid conditions in the RCS require overtemperature delta-T or overpower delta-T reactor trips until a trip is actually generated. The applicant presented additional information in the November 24, 1986 letter concerning the FSAR Chapter 15 non-LOCA accidents that rely on the above-mentioned trips. The non-LOCA accidents affected by the longer response time include (1) the uncontrolled rod cluster control assembly withdrawal, (2) the loss of load/turbine trip, (3) the inadvertent opening of a pressurizer safety or relief valve, (4) the uncontrolled boron dilution at power, and (5) the steamline rupture at power. These accidents are described in FSAR Sections 15.4.2, 15.2.3, 15.6.1, 15.4.6, and 15.1.5, respectively. The applicant stated that the LOFTRAN code was used for the first four accidents, and the results showed that the departure from nucleate boiling ratio (DNBR) criterion was met in all four accidents. For the uncontrolled-boron-dilution-at-power event, the results of the analysis show that the conclusions presented in the proposed revision to FSAR Section 15.4.6 remain valid; that is, there are more than 15 minutes available from the time of the alarm until total loss of plant shutdown margin. For the steamline-rupture-at-power event, the analysis included the increased response time and the increased temperature uncertainty allowance. The analysis showed that the design basis as described in WCAP-9226-R1 has been met.

In addition, system uncertainty calculations performed by the applicant verify that sufficient allowance has been made in the reactor protection system setpoints to account for an increased initial RCS average temperature error of 0.7°F (4.7°F vs 4.0°F). Although the new hot-leg RTD temperature sensor output is slightly more accurate than with the former RTD manifold method, the average of the sensor signals in a given hot leg is slightly less accurate because of the additional uncertainties introduced when the signal is sent to the QDPS for averaging before being sent to the 7300 processing system. However, the current values of nominal setpoints for the South Texas Technical Specifications were found to still be valid and, as a result, the accident analysis results were not changed.

In conclusion, the effect of the elmination of the RTD bypass for South Texas Units 1 and 2 on the FSAR Chapter 15 non-LOCA accident analyses has been evaluated and found acceptable. For the events affected by the increase in the channel response time, it has been demonstrated that the conclusions presented in the FSAR remain valid. For the remaining Chapter 15 non-LOCA events, the effect of the increased initial RCS average temperature error allowance has been ascertained by separate evaluations. In all instances, the conclusions presented in the South Texas FSAR remain valid under this error allowance assumption and the DNBR limit value is met. The applicant has stated that an analysis to support an RCS flow measurement uncertainty value, which includes the new hot-leg RTD temperature accuracy, will be provided later. This value of the RCS flow measurement uncertainty will be reviewed by the staff. If it is found to be acceptable, it will be used in Technical Specifications in place of the 3.5% value used in the Standard Technical Specifications.

6 ENGINEERED SAFETY FEATURES

6.5 Engineered Safety Feature Filter Systems

6.5.2 Containment Spray as a Fission Product Cleanup System

The applicant informed the staff by letter dated August 28, 1986, that a chemical additive tank associated with the containment spray sump had been deleted from the design. The justification provided indicated that the pH of the spray without this tank was sufficient to provide the required cleanup. By a letter dated October 17, 1986, the staff indicated to the applicant that the acceptance criterion for the pH control of the sump was being modified through a revision to the Standard Review Plan (SRP) (NUREG-0800). The proposed design puts the equilibrium sump pH as presented by the applicant into the acceptable range of the modified criterion. The staff concluded that the design change could be implemented. If problems should arise in the technical content of the applicant's submittal or if the SRP revision is not successful, a schedule for corrective actions would be established so that the licensing of Unit 1 would not be affected; hence, this item is considered resolved.

6.6 Inservice Inspection of Class 2 and 3 Components

6.6.1 Compliance With the Standard Review Plan

In the SER, the staff stated that the evaluation of the preservice inspection (PSI)/inservice inspection (ISI) program will be completed after the applicant submits the required examination information and identifies all plant-specific areas where American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section XI requirements cannot be met and provides the supporting technical justification. To date, the staff has received the required program descriptions and the following relief requests:

(1) to perform certain PSI examinations on component supports prior to initiation of hot functional testing

(2) to delete nondestructive examination of welds and visual examination of supports in open-ended portions of the containment spray system

(3) to delete surface examination of an inaccessible pipe weld in the safety injection system

(4) to delete ultrasonic testing (UT) of the inside-radius section of main steam nozzles in steam generators

(5) to document the extent of UT of reactor pressure vessel (RPV) welds and request acceptance of the untested portions

(6) to document the extent of UT and surface examination of Class 1 (except RPV) and Class 2 components and piping and request acceptance of the untested portions

The first relief request has been granted, and the evaluation is documented below. The remaining are under staff review and will be evaluated in the next supplement to the SER.

6.6.3 Evaluation of Compliance With 10 CFR 50.55a(g) for South Texas Unit 1

6.6.3.1 Relief From Preservice Examination Requirements of Component Supports

6.6.3.1.1 Relief Request Regarding Visual Examination

By letter dated May 22, 1986, the applicant requested relief from certain preservice inspection (PSI) examination requirements for component supports at South Texas Units 1 and 2. The PSI programs at South Texas Units 1 and 2 are based on the 1980 Edition through Winter 1981 Addenda of Section XI of the ASME Code. The following provides an evaluation of the applicant's request, supporting information, and alternative examinations or tests, as well as the staff's bases for granting the request pursuant to 10 CFR 50.55a.

Code Examination Requirements

(1) A VT-3* examination shall be performed on the following types of supports:

(a) plate and shell type supports
(b) linear type supports
(c) component standard supports except that a VT-4** examination shall be performed on spring type supports, constant load type supports, shock absorbers, and hydraulic and mechanical type snubbers

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*VT-3 (visual examination)

(1) The VT-3 visual examination shall be conducted to determine the general mechanical and structural conditions of components and their supports, such as the presence of loose parts, debris, or abnormal corrosion products, wear, erosion, corrosion, and the loss of integrity at bolted or welded connections.

(2) The VT-3 visual examination may require, as applicable to determine structural integrity, the measurement of clearances, detection of physical displacement, structural adequacy of supporting elements, connections between load-carrying structural members, and tightness of bolting.

(3) For component supports and component interiors, the visual examination may be performed remotely with or without optical aids to verify the structural integrity of the component.

**VT-4 (visual examination)

(1) The VT-4 visual examination shall be conducted to determine conditions relating to the operability of components or devices, such as mechanical and hydraulic snubbers, component supports, pumps, valves, and spring-loaded and constant weight hangers.

(2) The VT-4 visual examination shall confirm functional adequacy, verification of the settings, or freedom of motion. This examination may require disassembly of components or devices and operability test.

(2) The examinations shall include (a) mechanical connections to pressure-retaining components and building structure, (b) weld connections to building structure, (c) weld and mechanical connections at intermediate joints in multiconnected integral and nonintegral supports, (d) component displacement settings of guides and stops, (e) misalignment of supports, and (f) assembly of support items.

(3) All examinations shall be performed completely, once, as a preservice examination.

(4) All examinations shall be performed following the initiation of hot functional tests.

Code Relief Request

Relief is requested from performing certain examinations of component supports following the initiation of hot functional tests.

Applicant's Basis for Relief Request

The above requirement does not take into consideration those systems or portions of systems that are not heated or that are not affected by heatup during hot functional testing (HFT), nor does it take into consideration those aspects of visual (VT) examinations that are not affected by the thermal expansion of the piping system, that is, missing parts, locknuts, weld spatter, agreement with drawings, erosion, corrosion, etc. The applicant's PSI program encompasses approximately 1500 supports. Performing thorough examinations on these supports after initiation of HFT would create scheduling, access, and manpower problems during the period between the initiation of HFT and the start of low-power testing.

Applicant's Proposed Alternative Tests

(1) For those nonexempt systems or portions of systems that are not affected* by heatup during thermal expansion testing at HFT or power ascension testing (PAT), the required VT-3 and VT-4 (if applicable) examinations may be performed completely, before (but not to exceed 12 months) HFT.

(2) For those nonexempt systems or portions of systems that are affected* by the heatup during thermal expansion testing (see Attachment 1 to the applicant's submittal), the required VT-3 and VT-4 examinations, except setting verification and clearance checks, may be performed not more than 12 months before initiation of HFT, provided those same supports receive a post-heatup examination (if accessible**) to check for evidence of physical damage, misalignment, and bent or broken parts.

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*If a portion of a system exceeds 200°F during the test, that portion is considered to be affected by the heatup. Additionally, branch piping connected to portions of a system exceeding 200°F during the test is considered to be affected by the heatup.

**Those portions of systems heated only during PAT may be inaccessible because of as low as is reasonably achievable considerations. Inaccessible supports will be documented accordingly in the examination records.

Validity of the pre-HFT examination results will be ensured by enforcement of administrative procedures that control the integrity of examined supports.

Staff Evaluation and Conclusions

The VT-3 and VT-4 examinations are required to assess (1) the mechanical and structural condition and (2) the structural integrity of supports. The mechanical and structural condition of supports is determined by visual examination to detect the presence of debris, abnormal corrosion products, loose parts, wear, erosion, corrosion, and the loss of integrity at bolted or welded connections. The structural integrity of supports is determined by visual examination to detect physical displacement, structural adequacy of supporting elements, required clearances, and tightness of bolting.

The applicant's proposed alternative examination of the supports entails performing those required portions of the VT-3 or VT-4 examinations related to the determination of the structural condition of the supports during system walkdowns and drawing verifications before (but not to exceed 12 months) HFT or power ascension testing (PAT). Those required portions of the VT-3 or VT-4 examinations related to the determination of the structural integrity of the supports will be implemented during HFT or PAT and will encompass those supports in, or affected by, systems or portions of systems in which the temperature exceeds 200°F. In situations where a support is affected by service loadings and the required VT-3 or VT-4 examinations to assess the structural integrity of the supports cannot be performed during HFT or PAT because of high temperature, radiation levels, or inaccessibility, the applicant has proposed to perform the required exmainations after HFT or after PAT (as applicable).

The staff has reviewed the visual examination requirements for supports, the applicant's request, the supporting information, and proposed alternatives. On the basis of the purposes of the requirements, those portions of the examination related to the determination of the mechanical and structural condition of the supports in systems that operate below 200°F and are not affected by other systems or portions of other systems affected by service loadings may be performed before HFT or PAT to verify the integrity of bolted or welded connections and clearances. Performing the VT-3 and VT-4 examinations of those supports in systems operating above 200°F before HFT or PAT will eliminate from the failure evaluation those causes not related to service loadings. Since the applicant reports that there are approximately 1500 supports in the PSI program, performing all of the required VT-3 or VT-4 examinations during HFT or PAT is impractical and places an undue burden on the applicant without a compensating increase in the quality or safety of the plant. The staff has determined that the applicant's proposed alternatives adequately address the concerns associated with determining the structural condition and structural integrity of the supports at South Texas Units 1 and 2. The proposed alternatives will provide an acceptable level of quality and safety with the requirement that the post-HFT or post-PAT examinations of the inaccessible supports be performed during the immediate cold shutdown. The staff, therefore, concludes that relief from the VT-3 and VT-4 examination requirements as requested may be granted.

6.6.3.1.2 Augmented PSI Program

In the SER, the staff stated that the chemical and volume control system (CVCS) should be included in the augmented program. Subsequently, in a letter dated June 9, 1986, the applicant provided comments to the effect that the CVCS need not be included because it is not part of the emergency core cooling system at the South Texas Project. The staff agrees that exclusion of the CVCS from the augmented program is acceptable so long as the requirements consistent with the ASME Code Section IX classification are met.

7 INSTRUMENTATION AND CONTROLS

7.5 Information Systems Important to Safety

7.5.2 Specific Findings

7.5.2.4 Postaccident Monitoring Instrumentation Conformance to RG 1.97, Revision 2

The applicant was requested by Generic Letter 82-33 to provide a report to the NRC describing how the postaccident monitoring instrumentation meets the guidelines of Regulatory Guide (RG) 1.97 as applied to emergency response facilities. The applicant's response to RG 1.97 was provided by letters dated September 25, 1984, March 26, 1986, and May 23, 1986.

A detailed review and technical evaluation of the applicant's submittals were performed by EG&G Idaho, Inc., under contract to the NRC, with general supervision by the NRC staff. This work was reported by EG&G in the Technical Evaluation Report (TER), "Conformance to Regulatory Guide 1.97, South Texas Project, Unit Nos. 1 and 2," dated November 1986 (see Appendix R to this supplement). The report concludes that the applicant either conforms to, or is justified in deviating from, the guidance of RG 1.97 for each postaccident monitoring variable except for containment sump water temperature. The staff is continuing to review the deviation from the guidance of RG 1.97 for the containment sump water temperature and will report the conclusion in a future supplement.

Subsequent to the issuance of the generic letter, the NRC held regional meetings in February and March 1983 to answer licensee and applicant questions and concerns regarding the NRC policy on RG 1.97. At these meetings, it was established that the NRC review would only address exceptions taken to the guidance of RG 1.97. Further, where licensees or applicants explicitly state that instrument systems conform to the provisions of the regulatory guide, no staff review would be necessary for these items. Therefore, the review performed and reported by EG&G only addresses exceptions to the guidance of RG 1.97. This safety evaluation addresses the applicant's submittals on the basis of the review policy described in the NRC regional meetings and the conclusions of the review as reported by EG&G.

RG 1.97 recommends that Category 2 instrumentation be provided to monitor the containment sump water temperature. Section 3.3.19 of the EG&G TER states that the applicant does not have instrumentation or alternative instrumentation for this variable that is fully qualified to the Category 2 requirements. Thus, in a postaccident situation, a quantitative measure of the heat removal by way of the containment sump would not necessarily be available.

The applicant states that sump water temperature is not used in its Emergency Operating Procedures, and it is not needed for assurance that minimum net positive suction head (NPSH) requirements are met since NPSH calculations conservatively assume saturated water is present. The applicant further states that sump water is only used during the recirculation phase of an accident (i.e., pump suction switched over to containment sump). The sump water is cooled during this mode by the residual heat removal (RHR) heat exchangers in the low head safety injection (LHSI) flowpaths. Monitoring of this cooling function is provided by RHR heat exchanger discharge temperature, component cooling water (CCW) pump and valve status, CCW header temperature, and LHSI pump and valve status. The parameters are all monitored using Category 2 instrumentation. The staff is currently reviewing the need for Category 2 instrumentation to monitor the containment sump water temperature and will report the conclusion in a future supplement. In a letter dated November 3, 1986 (V. S. Noonan, NRC, to J. H. Goldberg, HL&P), the staff informed the applicant that it is in the process of developing a regulatory position that may affect the acceptability or otherwise of the applicant's position. The applicant's current design is acceptable on an interim basis pending the outcome of the clarification of the regulatory position. Hence, this item is considered closed at this time predicated on future regulatory action to be taken by the staff.

From Section 3.3.16 of Appendix R, it is noted that the applicant is utilizing Category 2 indication of pressurizer heater breaker position rather than the RG 1.97 recommendation of pressurizer heater current. Circuit breaker indication does not provide direct indication of pressurizer heater status as does monitoring the heater current. Standard Technical Specifications and the South Texas Project Technical Specifications, however, require that the heaters be checked quarterly to determine that the minimum required current is drawn by each heater group. Also, the operator's primary indication of proper pressurizer heater operation is from the reactor coolant system pressure instrumentation. Therefore, the staff finds that the Technical Specification surveillances together with the circuit breaker position indication for the pressurizer heaters provide status indication of the heaters commensurate with their safety function during an accident and are acceptable.

Conclusion

On the basis of its review of the TER and the applicant's submittals, the staff finds that the South Texas Units 1 and 2 design is acceptable with respect to conformance to RG 1.97, Revision 2, with the exception of the instrumentation for containment sump water temperature. The applicant's position on instrumentation for containment sump water temperature is under review, and the staff's conclusion will be reported in a future supplement. At this time, the item is considered closed as indicated above.

7.5.2.5 Qualified Display Processing System Software Verification and Validation Program

In the SER, the staff stated that three audits would be conducted to evaluate the verification and validation program associated with the qualified display processing system. The staff has, in fact, conducted four such audits, the last one during November 18-19, 1986. On December 23, 1986, the applicant submitted the final report on the verification and validation program. The staff is reviewing this report and will present the evaluation in the next supplement. In the meantime, Appendix S of this supplement provides the results of the fourth audit, which shows that all the open items identified so far have been resolved.

9 AUXILIARY SYSTEMS

9.3 Process Auxiliaries

9.3.2 Process and Postaccident Sampling Systems

9.3.2.2 Postaccident Sampling System (NUREG-0737, Item II.B.3)

In the SER, the staff concluded that the postaccident sampling system met 10 of the 11 criteria of Item II.B.3 in NUREG-0737 and that the remaining criterion, requiring a procedure for estimating the extent of reactor core damage, should be carried as a confirmatory item. The applicant was expected to provide a plant-specific procedure for estimating the extent of core damage based on Westinghouse Owners Group methodology, before fuel load.

By letters dated October 9 and December 15, 1986, the applicant provided additional, relevant information.

Criterion (2) of Item II.B.3 in NUREG-0737 states:

> The applicant shall establish an onsite radiological and chemical analysis capability to provide, within the three-hour time frame established above, qualification of the following:
>
> a) Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines, and cesiums, and non-volatile isotopes);
>
> b) hydrogen levels in the containment atmosphere;
>
> c) dissolved gases (e.g., H), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids;
>
> d) alternatively, have in-line monitoring capabilities to perform all or part of the above analyses.

The applicant provided a plant-specific procedure for estimating the degree of reactor core damage, based on the methodology developed by the Westinghouse Owners Group. The approach utilized in this procedure will take into consideration measurements of fission product concentration in the primary coolant system and containment atmosphere. The radionuclide measurements, together with readings from core exit thermocouples, water level indicators in the reactor vessel, containment radiation monitors, and containment atmospheric hydrogen analyzers, will be used to obtain a weighted assessment of various levels of fuel damage. It is the staff judgment that these provisions meet Criterion (2) of Item II.B.3 in NUREG-0737 and are acceptable.

The staff concludes that the applicant's proposed postaccident sampling system meets all 11 criteria of Item II.B.3 of NUREG-0737 and is, therefore, acceptable.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

9.5.1.7 Fire Protection of Safe Shutdown Capability

In the SER, the staff stated that its review of safe and alternate shutdown capability would be addressed in a supplement to the SER. The applicant has provided a fire hazard analysis report (FHAR) on safe and alternate shutdown capability following a fire, in accordance with the guidelines of SRP Section 9.5.1 (NUREG-0800) and Positions C.5.b and C.5.c of Branch Technical Position (BTP) CMEB 9.5.1 (attached to SRP Section 9.5.1). Further discussion of safe and alternate shutdown capability, including information on cable separation and safe shutdown, is contained in FSAR Sections 7.4, 8.3.1, and 9.5.1.

Safe Shutdown Capability

The staff's review of the fire protection afforded safe shutdown capability at South Texas included the FSAR, up to and including Amendment 56, and the FHAR, up to and including Amemdment 4. FSAR Section 9.5.1 describes the overall fire protection program; the FHAR discusses the safe shutdown capability, including the potential for spurious operation of equipment in each fire area. FSAR Section 7.4 provides additional information on controls and safe shutdown capability.

The South Texas safe shutdown capability consists of three redundant safe shutdown trains or pathways, powered from independent Class 1E power supplies. The applicant's safe shutdown and fire hazards analysis demonstrates that systems needed for hot and cold shutdown are redundant and that at least one of the redundant systems needed for safe hot and cold shutdown would be free of fire damage (except for the control room area) because of separation, fire barriers, and fire detection and suppression, or a combination of these. For a control room area fire (control room and relay room), alternate shutdown capability is provided. The safe shutdown analysis also included the component cabling and support equipment needed to achieve and maintain hot and cold shutdown conditions. Normally two redundant shutdown pathways will be available for safe shutdown of the plant following the occurrence of a fire at any given location, except in one area, within the containment (fire area 63, zone 202, elevation 68) where only one residual heat removal (RHR) success path will be available. This is due to the close proximity of two cubicle exhaust fans serving RHR trains A and B. However, one functional RHR path, i.e., train C, will still be available following a fire to bring the plant to safe shutdown conditions, as required by Position C.5.b of BTP CMEB 9.5-1.

For hot shutdown and cooldown to cold shutdown conditions, the auxiliary feedwater (AFW) system, main steam system (from the steam generator to the main steam isolation valves, reactor coolant system, and chemical and volume control system would be available. For cold shutdown conditions, the RHR system would be available for long-term decay heat removal. A single train provides the capability to achieve cold shutdown conditions within 72 hours after a fire. The availability of these systems includes the components, cabling, electrical distribution panels, and support systems necessary to achieve cold shutdown. The support systems include the component cooling water system, essential cooling water system, the diesel generators and their support systems, necessary ventilation systems, chilled water system and necessary instrumentation and controls, including the qualified display processing system (QDPS). The QDPS provides data acquisition, display, and control functions in the main control room and at the auxiliary shutdown panels.

The above systems are used to achieve safe shutdown through various success paths, depending on the location of the fire. Reactivity control is accomplished through control rod insertion followed by boration from the refueling water storage tank or from the boric acid storage tanks. Reactor coolant system (RCS) inventory control is accomplished by charging with the letdown line isolated. RCS pressure control is accomplished with the power-operated relief valves, pressurizer auxiliary spray, or the pressurizer heaters. Core heat removal will occur through forced flow using the reactor coolant pumps, if available, or natural circulation. RCS heat removal is accomplished using the AFW system, the main steam safety valves, or the power-operated main steam relief valves, down to a temperature of 350°F, at which time the heat removal function is transferred to the RHR system.

The applicant's fire hazard analysis demonstrated that except for the control room area, redundant systems and cabling needed for safe shutdown following a fire were adequately separated, in accordance with BTP CMEB 9.5-1, Position C.5.b. The applicant's fire hazard analysis for each fire area includes an evaluation of safe shutdown capability. The evaluation identifies a primary path and a redundant safe shutdown path that can be used in the event of a fire within the area or a zone of that area. The evaluation also identifies possible spurious actuations that can occur as a result of a fire in each area. Actions to overcome the spurious operations, or the compensatory measures to be taken, are indicated in the applicant's post-fire operator actions and equipment protection requirements (Report No. 5A019MFP001). Compensatory actions include tripping breakers, stopping specific pumps, and opening or closing certain valves. The staff has reviewed the postulated spurious actuations, and the actions necessary to overcome their effects, and concludes that the compensatory actions are relatively simple and straightforward. The staff further concludes that the analysis appears to have identified all possible spurious operations that may result from postulated fires.

A listing of the safe shutdown cables routed through each fire area is contained in document 5E019EL002, "Safe Shutdown Circuit Listing." The applicant used a computerized data base (EE 580) to identify all electrical circuits needed for safe shutdown, including associated circuits. The circuit raceway locations are identified in the data by fire zones and fire areas, as shown on the fire area drawings. The associated circuits of concern are those circuits, essential and nonessential, that are associated either because of a shared (with safe shutdown circuits) common power source or common enclosure, or whose fire-induced spurious operations could affect safe shutdown. The computer program provides a means to ensure adequate separation between safe shutdown trains and to identify potential adverse spurious actuations associated with each fire area.

The staff has reviewed the applicant's safe shutdown systems, methodology to ensure that the separation criteria of BTP CMEB 9.5-1, Position C.5.b, are met, and the associated circuits identified by the applicant, including the actions necessary to prevent or correct spurious operations that could affect safe shutdown. On the basis of this review, the staff concludes that the post-fire safe shutdown systems and the applicant's methodology for verifying the separation of safe shutdown system cabling and equipment satisfy Position C.5.b of BTP CMEB 9.5-1. Thus, the requirements of General Design Criterion (GDC) 3, "Fire Protection," of Appendix A to 10 CFR 50 for fire areas outside the control room are met.

Alternate Shutdown Capability

The applicant's safe shutdown analysis indicated that the only area where redundant divisions are not adequately separated by barriers in accordance with Position C.5.b is the control room area (control room and relay room). Alternate shutdown measures are required for the control room area in order to ensure the availability of the safe shutdown systems in the event of a control room fire.

Alternate shutdown capability for the control room is provided via the auxiliary shutdown panels, transfer switch panels, and local stations outside the control room. FSAR Section 7.4.1 describes the auxiliary shutdown panel's capability and identifies the instrumentation and controls located thereon. All three safe shutdown trains are isolable from the control room using the transfer switches which are predominantly located in the three redundant switchgear rooms. The remaining transfer switches are on the respective auxiliary shutdown panels in the train-related diesel generator rooms and are at the essential cooling water intake structure.

The alternate shutdown capability provides direct reading and controls to monitor the process variables necessary to perform reactivity control, reactor coolant makeup/inventory control, and reactor heat removal. The applicant has provided the following essential monitors at the auxiliary shutdown panel for achieving and maintaining safe shutdown:

(1) reactor coolant system (RCS) wide-range pressure
(2) RCS wide-range temperature (T_{hot} and C_{cold})
(3) pressurizer water level
(4) steam generator pressure
(5) steam generator wide-range level
(6) auxiliary feedwater flow to each steam generator
(7) chemical and volume control system charging flow
(8) reactor coolant pump seal injection flow
(9) auxiliary feedwater storage tank level
(10) refueling water storage tank level
(11) RHR flow and temperature
(12) neutron flux

The auxiliary shutdown panel also includes the controls for the following essential systems or components:

(1) auxiliary feedwater system
(2) centrifugal charging pumps
(3) boric acid transfer pumps
(4) letdown stop and isolation valves
(5) pressurizer power-operated relief valves (PORVs) and PORV block valve
(6) pressurizer backup heaters
(7) main steam PORVs

(8) RHR pump inlet isolation valves
(9) accumulator discharge isolation valves
(10) RCS isolation valves
(11) reactor head vent valves

Controls for RHR pumps, component cooling water pumps, essential cooling water pumps, necessary ventilation systems, and diesel generators are located at their local panels. Two trains of alternate shutdown control are provided for shutdown, with or without offsite power, within 72 hours.

The design of the auxiliary shutdown system complies with the performance goals outlined in Position C.5.c. of BTP CMEB 9.5-1. Reactivity control is accomplished by manual scram (before the operator leaves the control room) and boron addition via the chemical and volume control system (CVCS) using the refueling water storage tank (RWST) or boric acid tanks and controlling RCS letdown via the head vent or CVCS. The reactor coolant makeup and pressure control functions are also performed by the charging pumps and RWST. Reactor coolant inventory is assured by maintaining reactor coolant pump seal injection and by isolating all possible parts of inventory loss such as PORVs, RHR suction lines, letdown lines, and reactor head vents. RCS pressure control is also provided by PORVs or actuation of the pressurizer heaters. RCS heat removal is performed by the AFW system, main steam safety valves, or the power-operated main steam relief valves down to an RCS temperature of 350°F, at which time the heat removal function is transferred to the RHR system.

In addition to scramming the reactor from the control room, the applicant has included procedures for other actions that are to be performed before the control room is evacuated. These actions, however, can be performed outside the control room regardless of circuit damage within the control room. They include tripping the reactor coolant pumps, closing the PORV block valves, isolating the steam generators, and securing the charging pumps. The above actions could prevent a very unlikely series of events, which include spurious actuations, the failure of specific automatic functions, and the operation of other specific automatic functions, from causing RCS process variables to exceed those limits predicted for a loss of normal ac power. For example, consider the spurious closure of an isolation valve between the CVCS volume control tank and the charging pump, coupled with the simultaneous loss of offsite power (which signals both charging pumps to start) and having both pumps start. This assumes that circuits for starting both diesel generators and both charging pumps remain intact while certain other circuits fail in such a manner that the isolation valves between the RWST and the suction side of the charging pumps do not receive a signal to "open."

The transfer switches are designed so that even if fire damages the circuits before the position of transfer switches is changed, fuse replacement is not required for equipment operation after the transfer is complete. Thus, the design of the transfer switches adequately covers the concern identified in NRC Office of Inspection and Enforcement (IE) Information Notice 85-09, "Isolation Transfer Switches and Post-Fire Safe Shutdown Capability." The staff has reviewed the actions required by the procedures for achieving and maintaining safe plant shutdown following a control room fire. For hot standby, the immediate actions are mainly precautionary measures to ensure that some unusual combination of events does not occur and no spurious actuation is likely to occur because of a control room fire. If they do occur, the procedures can overcome or correct the inadvertent spurious actuations. To prevent spurious actuations of RHR suction isolation valves, the plant will operate with the power supply breakers for these valves locked in the tripped-open position when RCS pressure is greater than RHR system operating pressure.

For achieving and maintaining cold shutdown, some local operations may be required, such as opening of the RHR suction isolation valves. Otherwise cold shutdown is achieved and maintained at the auxiliary shutdown panels. The applicant has not identified any repairs that are required for cold shutdown. Cold shutdown can be achieved within 72 hours without offsite power.

On the basis of this review, the staff concludes that the alternate shutdown capability meets the criteria of SRP Section 9.5-1 by satisfying Position C.5.c of BTP CMEB 9.5-1 and meets the requirements of GDC 3, Fire Protection," for a control room area fire and is, therefore, acceptable.

13 CONDUCT OF OPERATIONS

13.5 Plant Procedures

13.5.2 Operating and Maintenance Procedures

13.5.2.4 NUREG-0737 Item III.D.1.1, Primary Coolant Outside Containment

In Amendment 53 to the FSAR, the applicant provided its program to comply with NUREG-0737 Item III.D.1.1. Except as noted below, the applicant has complied with the guidance for items listed in NUREG-0737. The applicant has identified the applicable systems and has developed a program aimed at minimizing the leakage from these systems by scheduled maintenance and testing per ASME Code Section XI.

The applicant excluded from the leakage reduction program the letdown, charging, and seal water portions of the chemical and volume control system (CVCS) because the CVCS is isolated during an accident and is not required to function after the accident. The staff notes that although the CVCS is not an engineered safety features system required to function during an accident, it may be desirable to activate the CVCS to degas the reactor coolant or to provide an alternate path for injecting water into the reactor system or for coolant inventory control. This being the case, the CVCS would contain highly radioactive fluid and consequently should be included with other systems covered by the leakage reduction program. Accordingly, the applicant should also apply the leakage reduction program to the CVCS. This will continue to be carried as a confirmatory item limited to the CVCS.

15 ACCIDENT ANALYSIS

15.4 Reactivity and Power Distribution Anomalies

15.4.6 Inadvertent Boron Dilution

In the SER, the staff reported that the applicant had provided for staff review analyses for the refueling, startup, full-power and hot standby modes, but not for the hot- and cold-shutdown modes (modes 4 and 5). Also, the applicant had not provided all the information requested regarding the analytical model used in the boron dilution calculations. In a submittal dated September 30, 1986, the applicant provided a report entitled "Probabilistic Boron Dilution Analysis" and proposed FSAR change pages. Although the submittal indicated that at least 15 minutes were available for operator response in the event of a boron dilution transient in modes 3, 4, and 5, the staff had concerns regarding the use of probabilistic methods and the analytical methodology in some areas of the report. These were discussed at a meeting with the applicant on October 30, 1986, at which time the applicant provided information to justify the position that the report of September 30, 1986, is a deterministic evaluation and does not use probabilistic methods for licensing. The staff is awaiting information that justifies the maximum dilution flow rate and the methods for determining the time when loss of shutdown margin occurs for modes 4 and 5.

15.6 Decrease in Reactor Coolant Inventory

15.6.5 Loss-of-Coolant Accident Resulting From Spectrum of Postulated Piping Breaks Within the Reactor Coolant Pressure Boundary

15.6.5.1 Loss-of-Coolant Accident

In the SER, the staff reported that the applicant was expected to provide information to justify acceptability of the TREAT code with regard to conformance with 10 CFR 50, Appendix K. The applicant provided a report in a submittal dated September 30, 1986, to respond to open item 16. Subsequently, the staff expressed concerns regarding the comparison of the results from TREAT and NOTRUMP and the predictions for natural circulation cooldown. At a meeting on January 16, 1987, the applicant showed that the results from TREAT and NOTRUMP are comparable with a time displacement of some of the predicted phenomena. In addition, the applicant provided information to justify its position that a natural circulation cooldown can be accomplished without creating a bubble in the vessel head. The information provided is currently under staff review.

15.8 Anticipated Transients Without Scram

15.8.1 ATWS Rule--ATWS Mitigation System

In the SER, the staff indicated that the generic design features to mitigate an anticipated transient without scram (ATWS) were under review and the South Texas plant-specific design would be evaluated in accordance with a review schedule. The staff also stated that staff review and approval were not requirements for plant licensing. In view of the fact that the applicant provided the required design information for staff review on October 20, 1986, the staff considers this confirmatory item resolved. The submittal of October 20, 1986 invokes the approved Westinghouse Topical Report WCAP-10858, "AMSAC Generic Design Package."

15.8.2 Generic Letter 83-28--Actions

The staff provided the results of the review of the applicant's submittals on Generic Letter 83-28 in Supplement 1 to the SER. In it, the staff reported that Items 1.1, 1.2, 2.1.1, 3.1.3, 3.2.3, 4.1, 4.2.1, 4.2.2, and 4.3 were acceptably resolved. It was noted that the remaining items, namely 2.1.2, 2.2.1, 2.2.2, 3.1.1, 3.1.2, 3.2.1, 3.2.2, 4.5.1, 4.5.2, and 4.5.3 would be addressed in future supplements. The staff has reviewed four additional items, and the results are reported below:

(2) Equipment Classification and Vendor Interface

Action Item 2.1: Reactor Trip System Components

Action Item 2.1 (Part 2): Vendor Interface Program (RTS Components)

Item 2.1 (Part 2) requires the applicant to confirm that an interface has been established with the nuclear steam system supplier (NSSS) or with the vendors of each of the components of the reactor trip system (RTS) which includes

(1) periodic communication between the licensee/applicant and the NSSS or the vendors of each of the components of the reactor trip system

(2) a system of positive feedback that confirms receipt by the licensee/applicant of transmittals of vendor technical information

The applicant responded to the requirements of Item 2.1 (Part 2) with a submittal dated June 28, 1985. The applicant stated in this submittal that Westinghouse is the NSSS for South Texas Units 1 and 2 and that the RTS is included as part of the Westinghouse interface program established for this plant. The response also confirms that this interface program includes both periodic communication between Westinghouse and the applicant and positive feedback from the applicant in the form of signed receipts for technical information transmitted by Westinghouse.

On the basis of its review of this response, the staff finds that the applicant's statements confirm that a vendor interface program exists with the NSSS for components that are required for performance of the reactor trip function. This program meets the requirements of Item 2.1 (Part 2) of Generic Letter 83-28 and is, therefore, acceptable. The results of the review performed by the staff's contractor is included as Appendix T.

Action Item 2.2: Programs for all Safety-Related Components

Item 2.2 states a staff position for equipment classification and vendor interface for all safety-related components. The applicant submitted a response to

Item 2.2 by letter dated June 28, 1985. Staff review of that response for Part 1 (Equipment Classification) of Item 2.2 has disclosed the need for additional confirmation as indicated below:

Action Item 2.2.1: Equipment Classification (Program)

The applicant's response does not confirm that all safety-related components are designated as safety related on plant documents such as procedures, system descriptions, test and maintenance instructions, and operating procedures and in information handling systems so that personnel performing activities that affect such safety-related components are aware that they are working on safety-related components and are guided by safety-related procedures and constraints.

Action Item 2.2.1.2: Information Handling System

The applicant's response has not confirmed that the information handling system includes a list of safety-related equipment and that procedures exist that govern its development and validation.

The applicant's response has not confirmed that identical criteria and procedures are used to govern the Q-list and the Master Parts List so that there are official, concise, and unambiguous listings.

(4) Reactor Trip System Reliability Improvements

Action Item 4.2: Preventative Maintenance and Surveillance Program for Reactor Trip Breakers

Action Items 4.2.3 and 4.2.4: Reactor Trip System Reliability

Item 4.2 required the licensees and applicants to submit a description of their preventive maintenance and surveillance program to ensure reliable reactor trip breaker (RTB) operation. The description of the submitted program was to include the following:

(1) Item 4.2.3--life testing of the breakers (including the trip attachments) on an acceptable sample size

(2) Item 4.2.4--periodic replacement of breakers or components consistent with demonstrated life cycles

The applicant submitted a response to Items 4.2.3 and 4.2.4 of the generic letter on June 28, 1985.

The purpose of the life testing is to identify a qualified life for the RTB or any of its replaceable components as required by 10 CFR 50.55a(h). By definition, qualified life is the period of time for which satisfactory performance can be demonstrated for a specific set of service conditions. The qualification methods that can be used to determine the qualified life, including the effects of aging, are identified in Institute of Electrical and Electronics Engineers (IEEE) Standard 323-1974. IEEE Standard 323-1974 provides guidance on aging based on an awareness that the ability of Class 1E equipment to perform its safety function may be affected by changes caused by natural, operational, and environmental phenomena over time. The concept of aging was addressed explicitly for the first time in IEEE Standard 323. The aging guidance therein reflects the requirement of IEEE Standard 279, which is the standard specifically mentioned in 10 CFR 50.55a(h). Conformance with IEEE Standard 323-1974 is a method, acceptable to the staff, of meeting the equipment qualification requirements of 10 CFR 50.55a(h).

If it can be demonstrated that the qualified life exceeds the life of the generating station, then the specific qualified life need not be identified. In a practical sense, the intent of the life testing requirement of the generic letter would be satisfied by demonstrating that the qualified life of the breaker (for the tripping function) exceeds the expected use projected to the next refueling. Cycling testing by the various owners groups, although it does not consider the effects of aging, may provide evidence to support continued use of the RTBs for one additional refueling cycle, provided the individual breaker has not shown any sign of degradation in the applicant's parametric trend monitoring program. In this approach the actual qualified life is not specifically identified, but only demonstrated to be adequate.

Ongoing life testing, as described in IEEE Standard 323-1974, is an acceptable alternative to formal life testing for the purpose of establishing a specific qualified life for RTBs. Ongoing life testing will demonstrate that the qualified life, although not specifically known, is longer (in terms of cycles and time) than the integrated service that will be accumulated through the next refueling interval. The description of an ongoing qualification program should include the following:

(1) definition of the number of demands per unit of time, to which an RTB must respond, and the basis for the number of demands

(2) definition of relevant, end-of-life related failures (note that random failures occurring during the constant hazard rate portion of the "bathtub curve" are not relevant to a life test)

(3) definition of the action to be taken upon any failure

If the qualified life of any component is less than the qualified life of the RTB, then the component should be replaced on an appropriately shorter time schedule. The criteria developed in support of this item include recordkeeping for service time and number of cycles for all breakers and short-lived devices or components.

The applicant states that life testing of the RTB trip attachments was reported in a draft Westinghouse report (later designated WCAP-10835), "Report of the DS-461 Reactor Trip Breaker Undervoltage and Shunt Trip Attachments Life Cycle Tests." The applicant endorses the conclusions of this report and will implement the recommendations of the report.

WCAP-10835 addresses only cyclic testing on RTB trip attachments. It does not address life qualification of the RTBs proper. It does not even address noncyclic life-limiting or performance-degrading phenomena (i.e., aging) for the trip attachments. Therefore, this WCAP report does not constitute an acceptable response to the concern of the generic letter.

The staff finds that the applicant has not committed to a life testing program. The breakers' qualified life must be established on the basis of actual testing of the breakers on an acceptable sample size. An ongoing life testing would be an acceptable alternative to formal life testing, provided the applicant's program includes the three requirements mentioned previously.

With respect to Item 4.2.4, the applicant will monitor RTB life cycles and establish component replacement guidelines that are consistent with the recommendations of the life cycle test report (WCAP-10835).

The staff finds the applicant's position on this item unacceptable. The applicant should identify a replacement program for the breaker and breaker components. The program should consider data derived from the ongoing life testing as well as the design life. If data from ongoing qualification are used, the applicant should consider inservice failures, malfunctions during the periodic maintenance program, and indication of degradation of failures from the measurements made for the trending of parameters. In addition, the applicant should specifically define how the ongoing qualification results will be used to establish replacement cycles and times.

The staff finds the applicant's responses on Item 4.2.3 and 4.2.4 of Generic Letter 83-28 to be unacceptable because they do not document the establishment of the qualified life of the RTB and its replaceable components.

However, Generic Letter 83-28 does not require that these items be resolved before an operating license is issued for South Texas. The schedule for resolution of these items is to be established by the staff's project manager for South Texas. The staff will report further on the resolution of these items in a future supplement.

Action Item 4.5: System Function Testing

Action Item 4.5.2: Reactor Trip System Reliability, On-Line Testing

Item 4.5 states a staff position which requires on-line functional testing of the reactor trip system, including independent testing of the diverse trip features of the reactor trip breakers, for all plants. Item 4.5.2 requires applicants and licensees with plants not currently designed to permit this periodic on-line testing to justify not making modifications to permit such testing. By letter dated June 28, 1985, the applicant responded to the staff position regarding Item 4.5.2 of Generic Letter 83-28.

The applicant stated that South Texas Units 1 and 2 are designed to allow on-line testing of the reactor trip system and that on-line functional testing will confirm the independent operability of the undervoltage and shunt trip devices.

The staff finds that South Texas Units 1 and 2 are designed to permit on-line functional testing of the reactor trip system, including independent testing of the diverse trip features of the reactor trip breakers. Thus, the applicant meets the staff position of Item 4.5.2 of Generic Letter 83-28. The evaluation provided by the staff's contractor is enclosed as Appendix U.

Having completed most of the review on Generic Letter 83-28, the staff has determined that the applicant meets the most significant of the requirements. On the basis of the review that has been completed so far, Open Item 17 in Table 1.4 is being converted to a confirmatory item and added to the listing in Table 1.5.

APPENDIX A

CONTINUATION OF NRC STAFF RADIOLOGICAL REVIEW OF THE SOUTH TEXAS PROJECT

September 28, 1983*	Letter from applicant concerning pipe break design considerations.
August 13, 1986*	Letter from applicant concerning safety-related instrument tubing program.
August 28, 1986*	Letter from applicant concerning Final Safety Analysis Report (FSAR) changes related to deletion of containment spray sump additive tank.
September 3, 1986	Representatives from NRC and HL&P meet in Bethesda, Maryland, to discuss the draft Emergency Plan for the South Texas Project. (Summary issued October 24, 1986.)
September 5, 1986	Letter from applicant concerning Generic Letter 81-07, "Control of Heavy Loads."
September 9, 1986	Letter to applicant transmitting 20 copies of the Final Environmental Statement (NUREG-1171) for the South Texas Project.
September 12, 1986	Letter from applicant concerning fuel assembly loads--SER Confirmatory Item 9.
September 15, 1986	Letter from applicant responding to NRC staff request for additional information on alternative pipe break criteria--pressurizer surge line.
September 15, 1986	Letter from applicant concerning annotated FSAR changes concerning the rule change to General Design Criterion 4.
September 15, 1986	Letter from applicant concerning procedures generation package.
September 15, 1986	Letter from applicant concerning Regulatory Guide (RG) 1.75 physical separation and SER Open Item 9 and supplying supplemental information on SER Open Item 9.

*Although the dates of these letters precede this continuation of chronology, they are included here because they respond to issues discussed in this supplement.

September 15, 1986	Letter from applicant concerning additional annotated FSAR changes concerning Section 3.6 pipe break criteria.
September 15, 1986	Letter from applicant responding to NRC staff request for additional information regarding TMI Action Plan Item II.E.4.2.(6)-- purge and vent valve operability.
September 16, 1986	Representatives from NRC, EG&G, and HL&P meet in Bethesda, Maryland, to discuss a proper foundation for the upcoming audits which are to be held at the end of October 1986. (Summarized by applicant on September 29, 1986.)
September 17, 1986	Letter from applicant concerning position on pipe break postulation relative to cumulative usage factor.
September 19, 1986	Letter to applicant concerning withholding of CAW-86-004 from public disclosure, which enclosed "South Texas Project Leak-Before-Break Screening Criteria for High Energy Auxiliary Piping Systems" (WCAP-11043).
September 24, 1986	Letter to applicant concerning cumulative usage factor for pipe break postulation.
September 29, 1986	Letter from applicant concerning Seismic Qualification Review Team/Pump and Valve Operability Review Team (SQRT/PVORT) preaudit meeting of September 16, 1986.
September 29, 1986	Letter from applicant concerning SER Confirmatory Item 4--main cooling reservoir performance at pool elevation +35 ft mean sea level.
September 30, 1986	Letter from applicant concerning SER Open Item 16 and Confirmatory Item 13--long-term cooling.
September 30, 1986	Letter from applicant concerning emergency dc lighting system.
September 30, 1986	Letter from applicant concerning response to NRC Generic Letter 86-14, "Operator Licensing Examinations."
September 30, 1986	Letter from applicant concerning boron dilution analysis--SER Open Item 15.
September 30, 1986	Letter from applicant concerning final response to Section A of NRC Generic Letter 85-12, "Implementation of TMI Action Item II.K.3.5, Automatic Trip of Reactor Coolant Pumps."
September 30, 1986	Letter from applicant transmitting revised pages for the response to SER Open Item 2--internal missile analysis.

October 1, 1986	Representatives from NRC, HL&P, and NRC consultants meet in Bethesda, Maryland, to discuss the submittals on leak-before-break and other pipe break postulation methods, which have been or are being reviewed by the staff. (Summary issued October 22, 1986.)
October 6, 1986	Letter from applicant concerning emergency classification procedure.
October 7, 1986	Letter from applicant concerning Matagorda County Emergency Management Plan.
October 7, 1986	Letter to applicant concerning report on the third audit of the qualified display processing system (QDPS) at South Texas Units 1 and 2.
October 9, 1986	Letter from applicant transmitting responses to SER Confirmatory Item 18 regarding NUREG-0737 Item II.B.3--postaccident sampling system.
October 9, 1986	Letter from applicant concerning responses to questions that arose from the SQRT/PVORT preaudit.
October 9, 1986	Letter to applicant withholding from public disclosure CAW-86-056, which transmitted "Supplemental Information Relative to Momentary Fuel Assembly Liftoff, Specific Data - TGX Fuel Assembly Forces."
October 10, 1986	Letter from applicant transmitting additional information concerning Section 3.6 pipe break criteria.
October 10, 1986	Letter from applicant transmitting FSAR Amendment 55.
October 15 & 16, 1986	Representatives from NRC and HL&P meet in Bethesda, Maryland, to discuss their application of leak-before-break technology and RG 1.75 separation criteria at South Texas Project. (Summary issued October 22, 1986.)
October 15, 1986	Letter from applicant concerning Emergency Plan.
October 16, 1986	Letter to applicant transmitting 20 copies of Supplement 1 to the SER.
October 16, 1986	Letter from applicant concerning annotated FSAR changes regarding reactor coolant system temperature measurement elimination of the bypass loop.
October 16, 1986	Letter from applicant concerning safety-related instrument tubing program.
October 17, 1986	Letter to applicant concerning the deletion of the containment spray sump additive tank.

October 20, 1986	Letter from applicant concerning annotated FSAR revisions concerning the main steam isolation valve closure logic--closure of Confirmatory Item 17.
October 20, 1986	Letter from applicant concerning FSAR submittal on ATWS mitigation system actuation circuitry (AMSAC) and response to 10 CFR 50.62--closure of Confirmatory Item 29.
October 24, 1986	Letter from applicant concerning fog monitoring program.
October 27, 1986	Letter from applicant concerning August 26, 1986 demonstration of ultrasonic examination of centrifugally cast stainless steel/statically cast stainless steel piping welds--meeting minutes.
October 30, 1986	Letter from applicant concerning fog monitoring program.
October 30, 1986	Representatives from NRC, HL&P, and Westinghouse meet in Bethesda, Maryland, to discuss the application of probabilistic methods for accident analysis. (Summary issued January 21, 1987.)
October 31, 1986	Letter from applicant concerning responses to SER Open Item 7 regarding the Electrical Isolator Test Report.
October 31, 1986	Letter from applicant concerning responses to NRC staff request for additional information on applicant's position on pipe break postulation relative to cumulative usage factor.
October 31, 1986	Letter from applicant concerning QDPS datalinks.
November 3, 1986	Letter from applicant concerning response to SER Open Item 1--internal flooding analysis.
November 3, 1986	Letter to applicant concerning status of NRC staff review of RG 1.97 submittals.
November 4, 1986	Letter from applicant concerning revised response to NRC Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events" (Section 2.2.1.2 only).
November 6, 1986	Representatives from NRC and HL&P meet in Bethesda, Maryland, to discuss the consideration of live loads in structural analysis. (Summarized by applicant on December 19, 1986.)
November 13, 1986	Letter from applicant concerning Emergency Plan Staff Augmentation Study.

November 13, 1986	Letter from applicant concerning clarification to the AMSAC FSAR submittal and transmittal of revised functional diagrams.
November 13, 1986	Representatives from NRC, HL&P, Westinghouse, Bechtel, and NRC consultants meet in Westinghouse office, Bethesda, Maryland, to prepare for and conduct the NRC staff audit of the QDPS. (Summary issued with fourth audit report.)
November 14, 1986	Letter from applicant concerning alternative pipe break criteria--accumulator line.
November 14, 1986	Letter from applicant transmitting FSAR Amendment 56 including revisions to Section 3.7.
November 17-21, 1986	Representatives from NRC, NRC consultants, and HL&P meet at the site to conduct the discussions and obtain additional information to develop the next iteration of the Technical Specifications based on the staff transmittal of October 29, 1986. (Summary to be issued.)
November 18, 1986	Letter from applicant concerning process control program.
November 19, 1986	Letter from applicant concerning RG 1.75 physical separation and SER Open Item 9 and supplying supplemental information on SER Open Item 9.
November 18-20, 1986	Representatives from NRC, NRC consultants, HL&P, Westinghouse, and Bechtel meet in Monroeville, Pennsylvania (Westinghous Training Center) to prepare for and conduct the NRC staff audit of the QDPS. This is the fourth of such audits at the vendor's facility. This audit is expected to be the final one in the series. (Summary issued with fourth audit report.)
November 20, 1986	Letter from applicant concerning emergency planning procedures.
November 24, 1986	Letter from applicant concerning annotated revisions regarding equipment qualification.
November 24, 1986	Letter from applicant concerning review of Westinghouse Class 1 Stress Reports.
November 24, 1986	Letter from applicant concerning resistance temperature detector bypass removal.
November 24, 1986	Letter from applicant concerning alternative pipe break criteria--pressurizer surge line.
November 26, 1986	Letter from applicant transmitting SQRT and PVORT forms.

November 26, 1986	Letter from applicant concerning update to turbine generator building heating, ventilating, and air conditioning.
November 29, 1986	Letter to applicant concerning NRC staff review of the South Texas Project Emergency Classification and Action Level Scheme.
December 1, 1986	Letter from applicant concerning additional information on the Advisory Committee on Reactor Safeguards report on South Texas Units 1 and 2 diesel generator fuel oil piping and vibration testing.
December 1, 1986	Letter from applicant concerning revision to table contained in the response to SER Open Item 1--internal flooding analysis.
December 5, 1986	Letter from applicant transmitting additional information regarding use of containment sump temperature indication for RG 1.97 postaccident monitoring.
December 5, 1986	Letter from applicant transmitting additional information concerning NRC Generic Letter 85-12, "Implementation of TMI Action Item II.K.3.5 Automatic Trip of Reactor Coolant Pumps."
December 5, 1986	Letter from applicant concerning Final Environmental Statement--impingement/entrainment monitoring program.
December 5, 1986	Letter from applicant concerning QDPS Noise, Fault, Surge, and Radio Frequency Interference Test Report.
December 8, 1986	Letter from applicant transmitting responses to NRC staff request for additional information on applicant's position on pipe break postulation relative to cumulative usage factor.
December 9, 1986	Letter from applicant concerning preservice inspection program.
December 9, 1986	Letter from applicant concerning emergency lighting systems.
December 9, 1986	Letter from applicant transmitting responses to NRC staff questions regarding review of the component cooling water pump logic diagrams.
December 10, 1986	Letter from applicant concerning revisions to responses to questions that arose from the SQRT/PVORT preaudit.
December 15, 1986	Letter from applicant transmitting supplemental information concerning SER Confirmatory Item 18 regarding NUREG-0737 Item II.B.3--postaccident sampling system.

December 15, 1986	Letter from applicant transmitting responses to NRC staff request for additional information on applicant's position on pipe break postulation relative to cumulative usage factor.
December 18, 1986	Letter from applicant concerning TMI Action Plan Item II.K.3.31--small-break loss-of-coolant-accident reanalysis--SER Confirmatory Item 34.
December 19, 1986	Letter from applicant concerning practices for the use of live loads at South Texas.
December 19, 1986	Letter from applicant concerning SER Open Item 18--bottom-mounted instrument thimble vibration.
December 22, 1986	Letter from applicant concerning annotated FSAR revision regarding the standby diesel generator fuel oil storage tank emergency fill connection.
December 22, 1986	Letter to applicant withholding from public disclosure CAW-86-100, "Alternative Pipe Break Criteria--Accumulator Line."
December 22, 1986	Letter to applicant concerning withholding from public disclosure CAW-86-096, "Cumulative Usage Factor Criterion for Break Postulation for South Texas, Units 1 & 2"--response to NRC staff request for additional information.
December 22, 1986	Letter to applicant concerning withholding from public disclosure CAW-86-068, which transmitted WCAP-11256, "Additional Information in Support of the Elimination of Postulated Pipe Ruptures in the Pressurizer Surge Lines of the South Texas Project, Units 1 and 2."
December 23, 1986	Letter from applicant concerning submittal of the Safety Parameter Display System (SPDS) Safety Analysis Report.
December 23, 1986	Letter from applicant submitting the OPDS Verification and Validation Program Final Report and response to the QDPS verification and validation SER open item.
December 23, 1986	Letter from applicant transmitting responses to confirmatory items regarding the control room design review.
December 23, 1986	Letter from applicant concerning supplementary information for the equipment qualification submittal.
December 26, 1986	Letter from applicant transmitting responses to confirmatory items regarding the control room design review.

December 26, 1986	Letter from applicant transmitting revisions to seismic Category I equipment qualification procedures (nuclear steam supply system scope).
December 30, 1986	Letter to applicant transmitting second draft of South Texas Unit 1 Technical Specifications.
December 31, 1986	Letter to applicant concerning Security Personnel Training and Qualification Plan for South Texas Project, Units 1 and 2.
December 31, 1986	Letter to applicant concerning the request for approval on use of increased cumulative usage factor.
January 4, 1987	Letter to applicant concerning NRC staff review of applicant's submittals for NUREG-0737 Item II.D.1, "Performance Testing of Relief and Safety Valves."
January 5, 1987	Letter from applicant concerning interim report on water damage to Unit 1 equipment.
January 5, 1987	Letter from applicant transmitting "Preservice Inspection Summary Report of Steam Generator Tubing"--SER Confirmatory Item 10 (Open Item 5).
January 7, 1987	Representatives from NRC AND HL&P meet at the South Texas site in Bay City, Texas, to conduct discussions regarding review on South Texas Technical Specifications. (Summary issued January 14, 1987.)
January 16, 1987	Representatives from NRC, HL&P, and Westinghouse meet in Bethesda, Maryland, to discuss recent submittals. (Summary issued January 21, 1987.)

APPENDIX B

BIBLIOGRAPHY

Code of Federal Regulations, Title 10, "Energy," U.S. Government Printing Office, Washington, DC, 1986.

U.S. Nuclear Regulatory Commission, 51 FR 12502, "Modification of General Design Criterion 4 Requirements for Protection Against Dynamic Effects of Postulated Pipe Ruptures," Final Rule, April 11, 1986.

---, Generic Letter 82-33, "Supplement 1 to NUREG-0737--Requirement for Emergency Response Capability," December 17, 1982.

---, Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events," July 8, 1983.

---, Generic Letter 84-04, "Safety Evaluation of Westinghouse Topical Reports Dealing With Elimination of Postulated Breaks in PWR Primary Loops," February 1, 1984.

---, Generic Letter 84-16, "Adequacy of On-Shift Operating Experience for Near-Term Operating License Applicants," June 27, 1984.

---, Generic Letter 85-12, "Implementation of TMI Action Item II.K.3.5, 'Automatic Trip of Reactor Coolant Pumps,'" June 28, 1985.

---, Generic Letter 86-16, "Westinghouse ECCS Evaluation Models," October 22, 1986.

---, NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980.

---, NUREG-0800 (formerly NUREG-75/087), "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," July 1981 (includes branch technical positions).

---, NUREG-1061, Vol. 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," November 1984.

---, Office of Inspection and Enforcement, IE Information Notice 85-09, "Isolation Transfer Switches and Post-Fire Safe Shutdown Capability," January 31, 1985.

Ward, D., Advisory Committee on Reactor Safeguards, letter to N. Palladino, NRC, "ACRS Report on South Texas Project Units 1 and 2," June 10, 1986.

Westinghouse Electric Corp., Report MT-SME-3078, "Technical Bases for Eliminating Large Primary Loop Ruptures as the Structural Design Basis for the South Texas Project Units 1 and 2," September 1983 (Westinghouse Class 2 proprietary).

---, WCAP-9226-R1, "Reactor Core Response to Excessive Secondary Steam Releases," Rev. 1, January 1978.

---, WCAP-9401, "Verification Testing and Analysis of the 17 x 17 Optimized Fuel Assembly," August 1981.

---, WCAP-9558, "Mechanistic Fracture Evaluation of Reactor Coolant Pipe Containing a Postulated Circumferential Throughwall Crack," Rev. 2, May 1981 (Westinghouse Class 2 proprietary).

---, WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," November 1983 (Westinghouse Class 2 proprietary).

---, WCAP-105559, "Technical Bases for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the South Texas Project Units 1 and 2," May 1984 (Westinghouse Class 2 proprietary).

---, WCAP-10835, "Report of the DS-416 Reactor Trip Breaker Undervoltage and Shunt Trip Attachments Life Cycle Test," May 1985 (proprietary).

---, WCAP-10858, "AMSAC Generic Design Package," June 1985.

INDUSTRY CODES AND STANDARDS

American National Standards Institute/American Nuclear Society, ANSI/ANS-3.1-1981, "Selection, Qualification and Training of Personnel for Nuclear Power Plants."

American National Standards Institute/American Society of Mechanical Engineers, ANSI/ASME Standard OM-3, "Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems," May 1985 draft.

American Society of Mechanical Engineers, Boiler and Pressure Vessel Code (ASME Code), Section III, "Rules for Construction of Nuclear Power Plant Components."

---, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," articles IWA-5000, IWC-5000, and IWD-5000.

---, Section XI, paragraphs IWV-3412, -3414, and -3417(a).

---, Section XI, 1980 Edition through Winter 1981 Addenda.

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---, IEEE Standard 323-1974, "Qualifying Class 1E Equipment for Nuclear Power Generating Stations."

APPENDIX D

ACRONYMS AND INITIALISMS

ACRS	Advisory Committee on Reactor Safeguards
AFW	auxiliary feedwater
AIB	arbitrary intermediate break
AMSAC	ATWS mitigation system actuation circuitry
ANS	American Nuclear Society
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient(s) without scram
BMI	bottom-mounted instrument
B&O	Bulletins and Orders
BTP	branch technical position
B&W	Babcock and Wilcox
CCW	component cooling water
CFR	Code of Federal Regulations
COA	City of Austin
CPL	Central Power and Light Company
CPS	City Public Service Board of San Antonio
CUF	cumulative usage factor
CVCS	chemical and volume control system
DEGB	double-ended guillotine break
DG	diesel generator
DNBR	departure from nucleate boiling ratio
ECCS	emergency core cooling system
ESF	engineered safety feature(s)
FHAR	Fire Hazards Analysis Report
FSAR	Final Safety Analysis Report
GDC	general design criterion(a)
HFT	hot functional testing
HL&P	Houston Lighting and Power Company
HPI	high pressure injection
IE	Office of Inspection and Enforcement
IEEE	Institute of Electrical and Electronics Engineers
ISI	inservice inspection
IST	inservice testing
LHSI	low head safety injection
LOCA	loss-of-coolant accident

MCR	main cooling reservoir
msl	mean seal level
NPSH	net positive suction head
NSSS	nuclear steam supply system
NSSS	nuclear steam system supplier
PAT	power ascension testing
PCP	process control program
PORV	power-operated relief valve
PSI	preservice inspection
PVORT	Pump and Valve Operability Review Team
QDPS	qualified display processing system
RCP	reactor coolant pump
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RTB	reactor trip breaker
RTD	resistance temperature detector
RTS	reactor trip system
RV	relief valve
RWST	refueling water storage tank
SER	Safety Evaluation Report
SPDS	safety parameter display system
SQRT	Seismic Qualification Review Team
SRP	Standard Review Plan
SSE	safe shutdown earthquake
SSER	supplement to Safety Evaluation Report
SV	safety valve
TER	Technical Evaluation Report
TMI	Three Mile Island
UT	ultrasonic testing

APPENDIX E

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This Supplemental Safety Evaluation Report is the product of the NRC staff and its consultants. The NRC staff members listed below were principal contributors to this report.

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APPENDIX P

EVALUATION OF WESTINGHOUSE REPORT WCAP-10456, "THE EFFECTS OF THERMAL AGING ON THE STRUCTURAL INTEGRITY OF CAST STAINLESS STEEL PIPING FOR WESTINGHOUSE NUCLEAR STEAM SUPPLY SYSTEMS"

APPENDIX P

EVALUATION OF WESTINGHOUSE REPORT WCAP-10456, "THE EFFECTS OF THERMAL AGING ON THE STRUCTURAL INTEGRITY OF CAST STAINLESS STEEL PIPING FOR WESTINGHOUSE NUCLEAR STEAM SUPPLY SYSTEMS"

INTRODUCTION

The primary coolant piping in some Westinghouse Nuclear Steam Supply Systems (NSSS) contain cast stainless steel base metal and weld metal. The base metal and weld metal are fabricated to produce a duplex structure of delta (δ) ferrite in an austenitic matrix. The duplex structure produces a material that has a higher yield strength, improved weldability, and greater resistance to intergranular stress corrosion cracking than a single-phase austenitic material. However, as early as 1965 (Ref. 1), it was recognized that long-time thermal aging at primary loop water temperatures (550°F-650°F) could significantly affect the Charpy impact toughness of the duplex structured alloys. Since the Charpy impact test is a measure of a material's resistance to fracture, a loss in Charpy impact toughness could result in reduced structural stability in the piping system.

The purpose of Report WCAP-10456 is to evaluate whether cast stainless steel base metal and weld metal containing postulated cracks will be sensitive to unstable fracture during the 40-year life of a nuclear power plant. In order to determine whether a piping system will behave in such a fashion, the pipe material's mechanical properties, design criteria, and method of predicting failure must be established. In this evaluation, we will assess the mechanical properties of thermally aged cast stainless steel pipe materials, which are reported in Report WCAP-10456.

DISCUSSION

1. Weld Metal

   Report WCAP-10456 refers to test results reported in a paper by Slama, et al. (Ref. 2) to conclude that the weld metal in primary loop piping would not be overly sensitive to aging and that the aged cast pipe base metal material would be structurally limiting. In the Slama report eight (8) welds were evaluated. The tensile properties were only slightly affected by aging. The Charpy U-notch impact energy in the most highly sensitive weld decreased from 7daJ/cm^2 (40 ft-lbs) to near 4daJ/cm^2 (24 ft-lbs) after aging for 10,000 hours at 400°C (752°F). This change was not considered significant. The relatively small effect of aging on the weld, as compared to cast pipe material, was reported to be caused by a difference in microstructure and lower levels of ferrite in the weld than in the cast pipe material.

2. Cast Stainless Steel Pipe Base Metal

Report WCAP-10456 contains mechanical property test results from a number of heats of aged cast stainless steel material and a metallurgical study, which was performed by Westinghouse, to support a statistically based model for predicting the effect of thermal aging on the Charpy impact test properties of cast stainless steel. As a result of these tests and the proposed model, Westinghouse concludes that the fracture toughness test results from one heat of material tested represents end-of-life conditions for the ten (10) plants surveyed. The ten (10) plants surveyed are identified as Plants A through J.

a. Mechanical Property Test Results Reported in WCAP-10456

Mechanical property test results on aged and unaged cast stainless steel materials which were reported in a paper by Landerman and Bamford (Ref. 3), Bamford, Landerman and Diaz (Ref. 4), Slama, et al. (Ref. 2) were discussed in Report WCAP-10456. In addition, Westinghouse performed confirmatory Charpy V notch and J-integral tests on aged cast stainless steel material, which was tested and evaluated by Slama, et. al.

The results of these tests indicate that:

(1) The fatigue crack growth rate of aged or unaged material in air and pressurized water reactor environments were equivalent.

(2) Tensile properties were essentially unaffected except for a slight increase in tensile strength and a decrease in ductility.

(3) J-integral test results indicate that the J_{1C} and tearing modulus, T, are affected by aging.

b. Mechanism Study in WCAP-10456

The tests and literature survey conducted by Westinghouse indicate that the proposed mechanism of aging occurs in the range of operating temperatures for pressurized water reactors, and the data from accelerated aging studies can be used to predict the behavior at operating temperatures.

c. Cast Stainless Steel Pipe Test

The materials data discussed in the previous section of this evaluation were obtained from small specimens. As a consequence, the J-R results are limited to relatively short crack extensions. To investigate the behavior of cast stainless steel in actual piping geometry, Westinghouse performed two experiments, one of which was with thermally aged cast stainless steel and the other was identical except that the steel was not thermally aged.

Each pipe tested contained a throughwall circumferential crack to the extent specified in WCAP-10456. The pipe sections were closed at the ends, pressurized to nominal PWR operating pressure and then bending loads were applied.

The results of the tests were very similar in that both pipes displayed extensive ductility and stable crack extension. There was no observed unstable crack extension or fast fracture.

The results of the Westinghouse pipe experiments indicate that cast stainless steel, both aged and unaged, can withstand crack extensions well beyond the range of the J-R results with small specimens. However, if crack extension is predicted in an actual application of thermally aged cast stainless steel in a piping system, we believe that it is prudent to limit the applied J to 3000 in.-lbs/in.^{2} or less unless further studies and/or experiments demonstrate that higher values are tolerable. Loss of initial toughness due to thermal aging of cast stainless steels at normal nuclear facility operating temperatures occurs slowly over the course of many years; therefore, continuing study of the aging phenomenon may lead to a relaxation of this position. Conversely, in the unlikely event that the total loss of toughness and the rate of toughness loss are greater than those projected in this evaluation, the staff will take appropriate action to limit the values to those which can be justified by experimental data. Because the aging is a slow process, the staff believes there would be sufficient time for the staff to recognize the problem and to rectify the situation. However, the staff believes this situation is highly unlikely because the staff has accepted only the lower bounds of data that were gathered among ten plants encompassing the range of materials in use.

d. Effects of Thermal Aging on Westinghouse Supplied Centrifugally Cast Reactor Coolant Piping Reported in WCAP-10456

The reactor coolant cast stainless steel piping materials in the plants identified in WCAP-10456 as A through J, were produced to the specification SA-351, Class CFBA as outlined in ASME Code Section II, Part A and also to Westinghouse Equipment Specification G-678864, as revised. For these materials, Westinghouse has calculated the predicted end-of-life Charpy U-notch properties, based on their proposed model. The two (2) standard deviation end-of-life lower limit value for all the plants surveyed was greater than the Charpy-U notch properties of the aged reference materials, which Westinghouse indicates represents end-of-life properties for all the plants. As a result, Westinghouse concluded that the amount of embrittlement in the aged reference material exceed the amount projected at end-of-life for all cast stainless steel pipe materials in Plants A through J.

Conclusions

Based on our review of the information and data contained in Westinghouse Report WCAP-10456, we conclude that:

1. Weld metal that is used in cast stainless steel piping system is initially less fracture resistant than the cast stainless steel base metal. However, the weld metal is less susceptible to thermal aging than the cast stainless steel base metal. Hence, at end-of-life the cast stainless steel base metal is anticipated to be the least fracture resistant material.

2. The Westinghouse proposed model may be used to predict the relative amount of embrittlement on a heat of cast stainless steel material. The two standard deviation lower confidence limits for this model will provide a useful engineering estimate of the predicted end-of-life Charpy impact properties for cast stainless steel base metal.

3. Since there is considerable scatter in J-integral test data for the heats of material tested, lower bound values for J_{Ic} and T should be used as engineering estimates for the fracture resistance of the aged reference material. We believe these values should also provide a lower bound for the fracture resistance of aged and unaged weld metal. If crack extension is predicted in an actual application of cast stainless steel in a piping system, we conclude that the applied J should be limited to 3000 in.-lbs/in.^{2} or less unless further studies and tests demonstrate that higher values are tolerable. The Westinghouse pipe tests demonstrate that this may be possible.

4. Since the predicted end-of-life Charpy impact values for the materials in Plants A through J are greater than the value measured for the aged reference material, the lower bound fracture properties for aged reference material may be used to determine the fracture resistance for the cast stainless steel material in Plants A through J.

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(2) G. Slama, P. Petrequin, S. H. Masson, and T. R. Mager, "Effect of Aging on Mechanical Properties of Austenitic Stainless Steel Casting and Welds," presented at SMIRT 7 Post Conference Seminar 6 - Assuring Structural Integrity of Steel Reactor Pressure Boundary Components, August 29-30, 1983, Monterey, CA.

(3) E. I. Landerman and W. H. Bamford, "Fracture Toughness and Fatigue Characteristics of Centrifugally Cast Type 316 Stainless Steel After Simulated Thermal Service Conditions. Presented at the Winter Annual Meeting of the ASME, San Francisco, CA, December 1978 (MPC-8 ASME).

(4) W. H. Bamford, E. I. Landerman, and E. Diaz, "Thermal Aging of Cast Stainless Steel and Its Impact on Piping Integrity." Presented at ASME Pressure Vessel and Piping Conference, Portland, Oregon, June 1983. To be published in ASME Trans.

APPENDIX Q

PUMP AND VALVE INSERVICE TESTING PROGRAM
FOR THE
SOUTH TEXAS PROJECT, UNIT 1

TECHNICAL EVALUATION REPORT
PUMP AND VALVE INSERVICE TESTING PROGRAM
SOUTH TEXAS PROJECT, UNIT 1

Docket No. 50-498

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ABSTRACT

This EG&G Idaho, Inc., report presents the results of our evaluation of the South Texas Project, Unit 1, Inservice Testing Program for safety-related pumps and valves.

FOREWORD

This report is supplied as part of the "Review of Pump and Valve Inservice Testing Programs for Operating Plants" Program being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A, by EG&G Idaho, Inc., NRR and I&E Support.

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Docket No. 50-498

CONTENTS

CONTENTS (Continued)

TECHNICAL EVALUATION REPORT
PUMP AND VALVE INSERVICE TESTING PROGRAM
SOUTH TEXAS PROJECT, UNIT 1

1. INTRODUCTION

Contained herein is a technical evaluation of the pump and valve inservice testing (IST) program submitted by the Houston Lighting & Power Company for its South Texas Project, Unit 1.

By a letter dated January 28, 1986 Houston Lighting & Power Company submitted an IST program for South Texas Project, Unit 1. The working session with Houston Lighting & Power Company and South Texas Project, Unit 1, representatives was conducted on June 10 and 11, 1986. The applicant's revised program, as attached to M. R. Wisenburg letter to NRC, dated August 12, 1986, which supercedes the previous submittal, was reviewed to verify compliance of proposed tests of Class 1, 2, and 3 safety-related pumps and valves with the requirements of the ASME Boiler and Pressure Vessel Code (the Code), Section XI, 1983 Edition through Summer 1983 Addenda. Any IST program revisions subsequent to those noted above are not addressed in this technical evaluation report (TER). It is an NRC staff position that required program changes, such as additional relief requests or the deletion of any components from the IST program, should be submitted to the NRC under separate cover in order to receive prompt attention, but should not be implemented prior to review and approval by the NRC.

In their submittal Houston Lighting & Power Company has requested relief from the ASME Code testing requirements for specific pumps and valves and these requests have been evaluated individually to determine whether they are indeed impractical. This review was performed utilizing the acceptance criteria of the Standard Review Plan, Section 3.9.6, and the Draft Regulatory Guide and Value/Impact Statement titled "Identification of Valves for Inclusion in Inservice Testing Programs". These IST Program testing requirements apply only to component testing (i.e., pumps and valves) and are not intended to provide the basis to change the applicant's current Technical Specifications for system test requirements.

Section 2 of this report presents the Houston Lighting & Power Company bases for requesting relief from the Section XI requirements for the South Texas Project, Unit 1 pump testing program and EG&G's evaluations and conclusions regarding these requests. Similar information is presented in Section 3 for the valve testing program.

The NRC staff's positions and guidelines concerning inservice testing requirements are provided in Appendix A.

Category A, B, and C valves that meet the requirements of the ASME Code, Section XI, and are not exercised quarterly are listed in Appendix B.

A listing of P&IDs used for this review is contained in Appendix C.

Inconsistencies and omissions in the applicant's program noted in the course of this review are listed in Appendix D. The applicant should resolve these items in accordance with the evaluations, conclusions, and guidelines presented in this report.

The details of valve cold shutdown testing justification are included in Appendix E.

2. PUMP TESTING PROGRAM

The South Texas Project, Unit 1, IST program submitted by the Houston Lighting & Power Company was examined to verify that all pumps that are included in the program are subjected to the periodic tests required by the AMSE Code, Section XI, 1983 Edition through Summer of 1983 Addenda, except for those pumps identified below for which specific relief from testing has been requested and is summarized in Appendix D. Each Houston Lighting & Power Company basis for requesting relief from the pump testing requirements and the EG&G reviewer's evaluation of that request is summarized below.

2.1 Essential Cooling Water System

2.1.1 Relief Request

The applicant has requested relief from the IWP-4200 requirement of Section XI for direct measurement of the Essential Cooling Water pump's inlet pressure and proposed to calculate the pump inlet pressure based on water level above the pump inlet.

2.1.1.1 Applicant's Basis for Requesting Relief. The Essential Cooling Water Pumps are vertical submerged suction centrifugal pumps with no direct means to measure inlet pressure as required. As an alternative, the inlet pressure will be calculated based on the water level above the pump inlet.

2.1.1.2 Evaluation. The reviewer agrees that pump inlet pressure cannot be measured directly for these vertical submerged impeller design service water pumps and that measurement of the head of water above the pump inlet would provide an adequate measure of the inlet pressure to the pump provided there is no increase in the restriction to flow at the pump inlet. Any flow restriction buildup at the pump inlet would be indicated by a decrease in pump discharge pressure and any significant change would require corrective action per IWP-3230.

2.1.1.3 Conclusion. The reviewer concludes that calculating inlet pressure should provide sufficient information to utilize to monitor pump degradation. The reviewer concludes that the alternate testing proposed will give reasonable assurance of pump operability required by the Code and, therefore, relief should be granted.

2.2 Residual Heat Removal System

2.2.1 Relief Request

The applicant has requested relief from the IWP-3100 requirements of Section XI for the residual heat removal (RHR) pumps for measurement of pump inlet and differential pressure and for varying system resistance to obtain the reference value of either measured differential pressure or measured flow rate and proposed to utilize a closed-loop fixed-resistance recirculation flow path to determine pump degradation.

2.2.1.1 Applicant's Basis for Requesting Relief. The inlet pressure of the residual heat removal pumps is measured using a local pressure indicator inside the reactor containment building and is considered inaccessible during power operation. The designed test flow path for these pumps consists of a closed-loop fixed-resistance recirculation flow path. As a result of this design, test values for initial inlet pressure, dynamic inlet pressure, and flowrate should not vary between tests. Outlet pressure at a given flow rate will be the true indicator of pump performance. As an alternative, pump testing will be performed at least once every three months as follows:

1. The RHR train to be tested will be lined up with the boundary valves of the test flow path closed and the recirculation valve open, creating the closed-loop fixed-resistance recirculation flow path desired.

2. Outlet pressure will be measured and compared to specific acceptance criteria to ensure the closed-loop system is filled. Note that the inlet pressure of the pump is equal to the outlet pressure in this line-up during static conditions.

3. The pump will be started and all parameters required by the Code except for inlet pressure and differential pressure will be measured. Flow will be verified to be correct, and outlet pressure (P_o) will be compared to the reference value for outlet pressure (P_{or}) with the following acceptance criteria:

   Acceptance Range = $.93\ P_{or} \leq P_o \leq 1.02\ P_{or}$

   Alert Range = $.90\ P_{or} \leq P_o \leq .93\ P_{or}$ or
   $1.02\ P_{or} \leq P_o \leq 1.03\ P_{or}$

   Action Range = $P_o < .90\ P_{or}$ or
   $P_o > 1.03\ P_{or}$

2.2.1.2 Evaluation. The reviewer agrees with the applicant that due to the RHR system's location inside the containment building and the lack of remote (external to containment and accessible during power operation) indications for pumps' inlet pressure that this measurement and the calculation of pump differential pressures are not practicable during quarterly pump testing during plant operation.

RHR pump inlet pressure is inferred from the pumps' discharge pressure measurement prior to the start of quarterly testing. During pump operation any change in inlet pressure to the pump will produce a corresponding change in the pump outlet pressure. The applicant's proposal to utilize pump discharge pressure in lieu of pump differential pressure in accordance with the requirements of Section XI, Table IWP-3100-2 for allowable ranges of differential pressure provides adequate information for evaluation of pump degradation and corrective action must be taken in accordance with IWP-3230. The applicant's use of a closed-loop fixed-resistance recirculation flow path in lieu of varying system resistance per IWP-3100 and the quarterly measurement of outlet pressure, plus all Code required parameters except for inlet pressure and differential pressure should provide sufficient information to utilize to monitor pump degradation.

Further, since all Code required parameters can be measured during cold shutdowns, the reviewer recommends that the applicant perform RHR pump testing in accordance with the Code requirements at each cold shutdown not to exceed once per quarter.

2.2.1.3 Conclusion. The reviewer concludes that utilization of a closed-loop fixed-resistance recirculation flow path to achieve conditions for measurement of all accessible parameters should provide sufficient information to utilize to monitor pump degradation during power operation, however, during cold shutdowns when all required parameters can be measured and recorded the applicant should test these pumps to the Code requirements. The reviewer concludes that this testing will give reasonable assurance of pump operability as required by the Code and, therefore, relief should be granted from the requirement to measure of pump inlet and differential pressure during power operation, however, all Code required parameters must be measured and evaluated during cold shutdowns.

2.3 Safety Injection System

2.3.1 Relief Request

The applicant has requested relief from the IWP-3100 requirement of Section XI for the high head safety injection (HHSI) and low head safety injection (LHSI) pumps for varying system resistance to achieve reference values and proposed to utilize recirculation flow paths with installed orifices to limit flow to a specific, fixed flow rate and compare the measured pump differential pressure to the allowable ranges in Table IWP-3100-2.

2.3.1.1 Applicant's Basis for Requesting Relief. Both the high head safety injection pumps and the low head safety injection pumps have a recirculation flow path containing a restricting orifice which limits flow through the recirculation line to a specific, fixed flow rate. When these pumps are tested using their respective fixed-resistance flow paths, the flow rates will be approximately the same each time the tests are conducted. As an alternative, pump testing will be performed using the fixed-resistance flow paths. The measured differential pressure will be compared to the allowable ranges given in Table IWP-3100-2 in order to determine pump operability.

2.3.1.2 Evaluation. The reviewer agrees with the applicant that quarterly measurement of all Section XI required parameters for the high head safety injection and low head safety injection pumps in a fixed-flow recirculation flow path should provide adequate information for determination of pump hydraulic performance. The applicant is measuring pump flow rate, inlet pressure, outlet pressure, and differential pressure for these pumps and these parameters can be assessed and compared to the vendor data on acceptable pump operation (i.e., pump specific head/flow curve) and an adequate determination of pump operability can be made.

2.3.1.3 Conclusion. The reviewer concludes that utilization of a fixed-flow recirculation flow path to achieve conditions for measurement of reference values should provide sufficient information to utilize to monitor pump degradation. The reviewer concludes that the alternate testing proposed will give reasonable assurance of pump operability required by the Code and, therefore, relief should be granted.

2.4 All Systems

2.4.1 Relief Request

The applicant has requested relief from the Table IWP-3100-1 requirements of Section XI for measurement or observation of lubricant level or pressure and bearing temperature for the following pumps:

Containment Spray Pumps 1A, 1B, and 1C
Boric Acid Transfer Pumps 1A and 1B
Essential Cooling Water Pumps 1A, 1B, and 1C
Residual Heat Removal Pumps 1A, 1B, and 1C
High Head Safety Injection Pumps 1A, 1B, and 1C
Low Head Safety Injection Pumps 1A, 1B, and 1C

2.4.1.1 Applicant's Basis for Requesting Relief. The bearings of the containment spray pumps, the boric acid transfer pumps, the essential cooling water pumps, the residual heat removal pumps, the high head safety injection pumps, and the low head safety injection pumps are lubricated and cooled by the pumped fluid making it impractical to verify proper lubricant level or pressure and measure bearing temperature. There is no alternate testing proposed for bearing temperature measurement.

2.4.1.2 Evaluation. The reviewer agrees with the applicant that since the pumped fluid provides cooling and lubrication for the pump bearings, that lubricant level or pressure and bearing temperature measurement would be unreliable as a method for detecting bearing failure because the data obtained is subject to considerable variations due to influences other than bearing condition. IWP-4310 specifically excludes measurement of bearing temperatures for bearings in the main flow path of the pump. Since the main flow path fluid is the lubricant, measurement of this temperature or pressure would not be indicative of adequate lubrication or cooling to the pump bearings. The reviewer feels that deletion of bearing temperature measurement and the lubricant observation for these pumps will not affect the applicant's pump monitoring program.

2.4.1.3 Conclusion. The reviewer concludes that the applicant's proposal to measure all pump parameters, except bearing temperature, should be sufficient to monitor pump degradation and that this testing will give reasonable assurance of pump operability as required by the Code and, therefore, relief should be granted.

3. VALVE TESTING PROGRAM

The South Texas Project, Unit 1, IST program submitted by the Houston Lighting & Power Company was examined to verify that all valves that are included in the program are subjected to the periodic tests required by the ASME Code, Section XI, 1983 Edition through Summer 1983 Addenda, and the NRC positions and guidelines. The reviewers found that, except as noted in Appendix D or where specific relief from testing has been requested, these valves are tested to the Code requirements and the NRC positions and guidelines summarized in Appendix A. Each Houston Lighting & Power Company basis for requesting relief from the valve testing requirements and the reviewer's evaluation of that request is summarized below and grouped according to system and valve category.

3.1 Containment Spray System

3.1.1 Category A/C Valves

3.1.1.1 Relief Request. The applicant has requested relief from exercising valves CS-0002, 0004, 0005, and 0006, containment spray (CS) pump discharge checks, in accordance with the requirements of Section XI, Paragraph IWV-3522, and proposed to verify valve operability by sample disassembly/inspection on a refueling frequency.

3.1.1.1.1 Applicant's Basis for Requesting Relief--Operability testing (full- or partial-stroke) of these normally closed check valves is impractical during power operation or cold shutdown. Stroking these valves with flow would require the spraying of containment which is impractical and may cause equipment damage. As an alternative, these check valves will be verified operable by disassembly of one check valve each refueling outage on a rotating basis for inspection to ensure no degradation has occurred. If the check valve selected during any refueling outage shows signs of unacceptable degradation, all other applicable check valves will be disassembled and inspected during that refueling outage.

3.1.1.1.2 Evaluation--The reviewer agrees that valves CS-0002, 0004, 0005, and 0006 cannot be full- or partial-stroke exercised during operation, cold shutdown, or refueling outage because flow through these valves would spray the containment and cause equipment damage.

The NRC staff has concluded that a valve sampling disassembly/inspection utilizing a manual full-stroke of one disk is an acceptable method to verify a check valve's full-stroke capability. The sampling technique requires that each valve in the group must be of the same design (manufacturer, size, model number and materials of construction) and must have the same service conditions. Additionally, at each disassembly it must be verified that the disassembled valve is capable of full-stroking and that its internals are structurally sound (no loose or corroded parts).

A different valve of each group is required to be disassembled, inspected and manually full-stroked at each refueling, until the entire group has been tested. If it is found that the disassembled valve's full-stroke capability is in question, the remainder of the valves in that group must also be disassembled, inspected, and manually full-stroked at the same outage.

Following successful disassembly, inspection, and manual full-stroking of all check valves in the group, the applicant may submit a relief request to the NRC requesting a change of the intervals between these tests. This relief request should contain all pertinent historical maintenance data on each valve, including the inspection and maintenance data obtained at each disassembly/inspection and manual full-stroke. Photographs should be provided of the valve "as found" internals, noting particularly any anomalies encountered.

3.1.1.1.3 Conclusion--The reviewer concludes that the applicant's proposal to perform sample disassembly/inspection on a refueling outage frequency, when performed in accordance with the previous discussion (Section 3.1.1.1.2), should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing proposed will give reasonable assurance of valve operability required by the Code and, therefore, relief should be granted.

3.2 Component Cooling System

3.2.1 Category C Valves

3.2.1.1 Relief Request. The applicant has requested relief from testing valve CC-0746, component cooling water (CCW), surge tank vacuum breaker check, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to verify valve operability by partial disassembly and inspection on a refueling frequency.

3.2.1.1.1 Applicant's Basis for Requesting Relief--Operability testing (full- or partial-stroke) of this normally closed check valve is impractical due to plant design. As an alternative, this valve will be required to be partially disassembled every refueling outage and the valve internals will be inspected to ensure no degradation has occurred.

3.2.1.1.2 Evaluation--The reviewer agrees that valve CC-0746 cannot be exercised with flow during power operation, cold shutdown, or refueling. This normally closed check valve has no provision for verification of partial- or full-stroke.

The NRC staff has concluded that valve disassembly/inspection using a manual full stroke of the disk is an acceptable method to verify the full-stroke capability of check valves. At each disassembly the applicant must verify that the disassembled valve is capable of full stroking and its internals are structurally sound (no loose or corroded parts).

3.2.1.1.3 Conclusion--The reviewer concludes that the applicant's proposal to perform disassembly/inspection on a refueling outage frequency, when performed in accordance with the previous discussion (Section 3.2.1.1.2) should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.3 Feedwater System

3.3.1 Category B Valves

3.3.1.1 Relief Request. The applicant has requested relief from exercising valves FCV-0551, 0552, 0553, and 0554, feedwater regulator valves, in accordance with the requirements of Section XI, Paragraphs IWV-3412 and 3414 and proposed to verify valve operability by partial-stroke exercising these valves during plant operation on a nonspecified frequency and full-stroke exercising them on a cold shutdown frequency.

3.3.1.1.1 Applicant's Basis for Requesting Relief--These valves are normally throttled open during power operations to maintain steam generator level by controlling feedwater flow. These valves cannot be tested without isolating feedwater from the steam generators causing undesirable power transients and possible turbine and reactor trip. As an alternative, these valves will be exercised (partial-stroke) during the course of normal plant operations (although the frequency cannot be specified as stated in IWV-3414) and required to be exercised (full-stroke) each cold shutdown not to exceed once every three (3) months.

3.3.1.1.2 Evaluation--The reviewer does not agree with the applicant that valves FCV-0551, 0552, 0553, and 0554 should have no specific frequency identified for partial-stroke exercising during power operation. The reviewer believes the applicant has the ability to partial-stroke exercise these valves at least quarterly during power operation. The reviewer agrees with the applicant that these valves can only be full-stroke exercised during cold shutdowns. To full-stroke exercise these valves during power operation would isolate steam generator feed and could result in power transients and possibly reactor trip.

3.3.1.1.3 Conclusion--The reviewer concludes that partial-stroke exercising these valves quarterly during power operation and full-stroke exercising these valves at cold shutdown should be sufficient to demonstrate proper valve operability. The reviewer concludes that the proposed nonspecified frequency for partial-stroke exercising these valves at power is an unjustified deviation from the Code requirements and, therefore, relief should not be granted.

3.4 Safety Injection System

3.4.1 Category A/C Valves

3.4.1.1 Relief Request. The applicant has requested relief from exercising valves XSI-0030A, 0030B, and 0030C, low head safety injection pump discharge checks, and XSI-0005A, 0005B, and 0005C, high head safety injection pump discharge checks, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to partial-stroke exercise these valves quarterly and full-stroke exercise these valves on a refueling outage frequency.

3.4.1.1.1 Applicant's Basis for Requesting Relief--These check valves can only be exercised (full-stroke) by simulating LOCA conditions (pumping into the RCS with RCS at zero or very low pressure) in order to get full pump flows. As an alternative, these check valves will be required to be exercised (partial-stroke) at least once every three (3) months by running pumps at normal recirculation flows, and exercised (full-stroke) each refueling outage by injecting into the RCS with the vessel head off using the appropriate pump(s) at full flow.

3.4.1.1.2 Evaluation--The reviewer agrees with the applicant that valves XSI-0030A, 0030B, 0030C, 0005A, 0005B, and 0005C cannot be full-stroke exercised except at refueling outages when the reactor vessel head has been removed. The high flowrates required through these valves can only be achieved when reactor coolant system (RCS) pressures are very low such as during refueling when an adequate expansion volume is available (i.e., head removed). Testing these valves during cold shutdown would risk low temperature overpressurization of the reactor coolant system and is not acceptable.

3.4.1.1.3 Conclusion--The reviewer concludes that the applicant's proposal to partial-stroke exercise these valves quarterly and full-stroke exercise them on a refueling outage frequency should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing frequency proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.4.1.2 Relief Request. The applicant has requested relief from exercising valves XSI-0009A, 0009B, and 0009C, HHSI pump hot leg checks, and XSI-0007A, 0007B, and 0007C, HHSI pump cold leg checks, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to verify valve operability by full-stroke exercising these valves on a refueling outage frequency.

3.4.1.2.1 Applicant's Basis for Requesting Relief--These check valves cannot be exercised (full- or partial-stroke) at power as the HHSI pumps cannot develop discharge pressure greater than normal RCS pressure. These check valve cannot be exercised (full- or partial-stroke) during cold shutdown as the HHSI pumps would overpressurize the RCS. As an alternative these valves will be required to be exercised (full-stroke) each refueling outage by injecting HHSI flow into the open and vented RCS.

3.4.1.2.2 Evaluation--The reviewer agrees with the applicant that valves XSI-0009A, 0009B, 0009C, 0007A, 0007B, and 0007C cannot be full- or partial-stroke exercised during power operation or cold shutdown. During power operation RCS pressure is above the HHSI pump's shutoff head and flow cannot be established to partial- or full-stroke exercise these valves. Testing these valves during cold shutdown would risk low temperature overpressurization of the RCS and is not acceptable.

3.4.1.2.3 Conclusion--The reviewer concludes that the applicant's proposal to full-stroke exercise these valves on a refueling outage frequency should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing frequency proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.4.1.3 Relief Request. The applicant has requested relief from testing valves XSI-0010A, 0010B, and 0010C, HHSI pump hot leg checks, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to partial-stroke exercise these valves on a cold shutdown frequency and full-stroke exercise these valves on a refueling outage frequency.

3.4.1.3.1 Applicant's Basis for Requesting Relief--These check valves cannot be exercised at power (full- or partial-stroke) since neither the HHSI, LHSI, nor RHR pumps can overcome RCS pressure. The valve cannot be exercised (full-stroke) unless LOCA conditions are simulated (pumping into RCS with RCS at zero or very low pressure) to get full pump flows. As an alternative these check valves will be required to be exercised (partial-stroke) each cold shutdown not to exceed once every three (3) months using RHR flow, and exercised (full-stroke) each refueling outage using HHSI and LHSI pump flows.

3.4.1.3.2 Evaluation--The reviewer agrees with the applicant that valves XSI-0010A, 0010B, and 0010C cannot be full- or partial-stroke exercised during power operation and cannot be full-stroke exercised during cold shutdown. During power operation RCS pressure is above HHSI, LHSI, and RHR pump shutoff head and flow cannot be established to partial- or full-stroke exercise these valves. These valves can be partial-stroke exercised during cold shutdown, however, the full flow necessary to full-stroke exercise these valves during cold shutdown would require an adequate expansion volume to accommodate the flow required and is not considered practicable at cold shutdown.

3.4.1.3.3 Conclusion--The reviewer concludes that the applicant's proposal to partial-stroke exercise these valves during cold shutdowns and to full-stroke exercise them on a refueling outage frequency should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.4.1.4 Relief Request. The applicant has requested relief from testing valves XSI-0046A, 0046B, and 0046C, safety injection (SI) system accumulator checks, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to verify valve operability by sample disassembly/inspection on a refueling frequency.

3.4.1.4.1 Applicant's Basis for Requesting Relief--These check valves cannot be exercised (full- or partial-stroke) at power since the SIS accumulator pressure is lower than the RCS pressure; cannot be exercised (full- or partial-stroke) during cold shutdown without the possibility of overpressurizing the RCS; and cannot be exercised (full-stroke) during a refueling outage as the high flow rate of a full discharge with the SIS accumulators at normal pressure may cause internal damage to the core. As an alternative these check valves will be verified operable by disassembly of one check valve each refueling outage on a rotating basis for inspection to ensure no degradation has occurred. If the check valve selected during any refueling outage shows signs of unacceptable degradation, all other applicable check valves will be disassembled and inspected during that refueling outage.

3.4.1.4.2 Evaluation--The reviewer agrees with the applicant that valves XSI-0046A, 0046B, and 0046C cannot be full- or partial-stroke exercised during operation or cold shutdown and that these valves cannot be full-stroke exercised during refueling outages. During power operation RCS pressure is much higher than accumulator pressure and flow cannot be established through these valves. During cold shutdown full- or partial-stroke exercising these valves could result in low temperature overpressurization of the RCS and is unacceptable. Full-stroke exercising these valves during refueling with the safety injection system accumulators at normal operating pressure could result in damage to reactor vessel internals and should not be performed.

The NRC staff has concluded that a valve sampling disassembly/inspection utilizing a manual full-stroke of one valve disk each refueling outage is an acceptable method to verify a valve's full-stroke capability (see further discussion in Section 3.1.1.1.2 of this report).

3.4.1.4.3 Conclusion--The reviewer concludes that the applicant's proposal to perform sample disassembly/inspection on a refueling frequency, when performed in accordance with the discussion in Section 3.1.1.1.2, should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.4.1.5 Relief Request. The applicant has requested relief from testing valves XSI-0038A, 0038B, and 0038C, SI cold leg checks, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to partial-stroke exercise these valves during cold shutdowns and perform sample disassembly/inspection on a refueling frequency.

3.4.1.5.1 Applicant's Basis for Requesting Relief--These check valves cannot be exercised at full power (full- or partial-stroke) since neither the HHSI pumps, LHSI pumps, RHR pumps, nor the SIS accumulators can overcome RCS pressure. These check valves cannot be exercised (full-stroke) during cold shutdown without the possibility of overpressurizing the RCS. These check valves cannot be exercised (full-stroke) during a refueling outage as the high flow rate required may cause internal damage to the core. As an alternative these check valves will be required to be exercised (partial-stroke) each cold shutdown not to exceed once every three (3) months using RHR flow, and these check valves will be verified operable (full-stroke capable) by disassembly of one check valve each refueling outage on a rotating basis for inspection to ensure no degradation has occurred. If the check valve selected during any refueling outage shows signs of unacceptable degradation, all other applicable check valves will be disassembled and inspected during that refueling outage.

3.4.1.5.2 Evaluation--The reviewer agrees with the applicant that valves XSI-0038A, 0038B, and 0038C cannot be full- or partial-stroke exercised during power operation and cannot be full-stroke exercised during cold shutdowns or refueling outages. Neither the HHSI pumps, LHSI pumps, RHR pumps, nor the SIS accumulators can overcome RCS pressure to establish flow through these valves during power operations. Full-stroke exercising these valves during cold shutdowns could result in low temperature overpressurization of the RCS and is unacceptable. These check valves cannot be full-stroke exercised during refueling outages because the high flowrates required could cause damage to reactor vessel internals.

The NRC staff has concluded that a valve sampling disassembly/inspection utilizing a manual full-stroke of one valve disk each refueling outage is an acceptable method to verify a valve's full-stroke capability (see further discussion in Section 3.1.1.1.2).

3.4.1.5.3 Conclusion--The reviewer concludes that the applicant's proposal to partial-stroke exercise these valves on a cold shutdown frequency and to perform sample disassembly/inspection on a refueling frequency, when performed in accordance with the discussion in Section 3.1.1.1.2 should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.4.2 Category C Valves

3.4.2.1 Relief Request. The applicant has requested relief from exercising valves XSI-0002A, 0002B, and 0002C, refueling water storage tank (RWST) outlet checks, in accordance with the requirements of Section XI, Paragraph IWV-3522 and proposed to partial-stroke exercise these valves quarterly and full-stroke exercise them on a refueling outage frequency.

3.4.2.1.1 Applicant's Basis for Requesting Relief--These check valves can only be exercised (full-stroke) by simulating LOCA conditions (pumping into the RCS with RCS at zero or very low pressure) in order to get full pump flows. As an alternative these check valves will be required to be exercised (partial-stroke) at least once every three (3) months by running pumps at normal recirculation flows, and exercised (full-stroke) each refueling outage by injecting into the RCS with the vessel head off using the appropriate pump(s) at full flow.

3.4.2.1.2 Evaluation--The reviewer agrees with the applicant that valves XSI-0002A, 0002B, and 0002C cannot be full-stroke exercised during power operation or cold shutdown. The high flow rate necessary to full-stroke exercise these valves can only be achieved with the RCS at very low (near atmospheric) pressure and, therefore, is only practical during refueling outages when the reactor vessel head is removed and is not practical during power operation or cold shutdown when plant pressures are significantly higher.

3.4.2.1.3 Conclusion--The reviewer concludes that the applicant's proposal to partial-stroke exercise these valves quarterly and full-stroke exercise them on a refueling outage frequency should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing frequency proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.5 Standby Diesel Generator Starting Air System

3.5.1 Category B Valves

3.5.1.1 Relief Request. The applicant has requested relief from stroke time testing the following valves in accordance with the requirements of Section XI, Paragraph IWV-3413 and proposed to verify valve operability by the use of a "Starting Air System Malfunction" alarm which would result if any valve failed to open sufficiently within one second of a start signal.

Valve Identification	Function
FV-5435	DG 11 right bank cranking air valve
FV-5434	DG 11 left bank cranking air valve
FV-5535	DG 12 right bank cranking air valve
FV-5534	DG 12 left bank cranking air valve
FV-5635	DG 13 right bank cranking air valve
FV-5634	DG 13 left bank cranking air valve

3.5.1.1.1 Applicant's Basis for Requesting Relief--These valves supply air to the standby diesel generator during the starting sequence establishing initial starting compression. Downstream of each redundant valve is a pressure switch that controls the alarm logic. The failure of either valve to open sufficiently within the second of a start signal will result in a Starting Air System Malfunction alarm. Normal testing of the diesel generator in accordance with Technical Specification will exercise both of these valves and verify stroke time less than one second by absence of alarms. This testing is performed at least once every 31 days on a staggered test basis. As an alternative, these valves will be required to be verified operable during normal diesel generator testing by verifying absence of the Starting Air System Malfunction alarm. No stroke times will be taken.

3.5.1.1.2 Evaluation--The reviewer agrees with the applicant that valves FV-5435, 5434, 5535, 5534, 5635, and 5634 cannot be stroke-timed since the valves are enclosed and no moving parts are visible. Downstream of these valves are pressure actuated switches which provide input to the system alarm logic. Failure of any one of these valves to open sufficiently for diesel start within one second of a start signal will result in a starting air system malfunction alarm.

3.5.1.1.3 Conclusion--The reviewer concludes that the applicant's use of the installed alarm logic to detect valve failure should be sufficient to demonstrate valve operability. The reviewer concludes that the alternate testing proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.6 All Systems

3.6.1 Corrective Action

3.6.1.1 Relief Request. The applicant has requested relief from testing all valves that require corrective action as a result of cold shutdown and refueling outage testing in accordance with the requirements of Section XI, Paragraphs IWV-3417(b) and IWV-3523 and proposed to utilize plant Technical Specifications to control whether plant startup is permissible or not.

3.6.1.1.1 Applicant's Basis for Requesting Relief--The plant Technical Specifications provide the requirements and plant conditions necessary for plant startup (i.e., mode changes). As an alternative, the test requirement will be satisfied before the valve is required to be operable in accordance with the plant Technical Specifications.

3.6.1.1.2 Evaluation--The reviewer agrees with the applicant that the plant Technical Specifications dictate the necessary requirements and plant conditions for plant startup (i.e., mode changes). The plant Technical Specifications place adequate controls on system and/or valve operability by establishing and defining the Limiting Conditions for Operation which restrict, allow, or require entry into the various mode of plant operation.

3.6.1.1.3 Conclusion--The reviewer concludes that the applicant's Technical Specification dictate the necessary requirements and plant conditions for startup and operations. The Section XI requirements determine component operability status and should not preclude plant startup when all applicable Technical Specifications requirements are met.

3.6.1.2 Relief Request. The applicant has requested relief from the corrective action requirements of Section XI, Paragraph IWV-3417(a) for all valves that require stroke timing and can only be exercised during cold shutdowns.

3.6.1.2.1 Applicant's Basis for Requesting Relief--Valves that are normally tested during cold shutdown cannot be tested once each month. Stroking these valves during normal plant operation may cause equipment damage, personnel hazards, or plant shutdown. As an alternative, the required test frequency will be once each cold shutdown, not to exceed once every month.

3.6.1.2.2 Evaluation--The reviewer does not agree with the applicant and relief should not be granted from the corrective action requirements of Section XI, Paragraph IWV-3417(a). These valves should be tested at the Code specified increased frequency or repaired prior to startup from cold shutdown.

3.6.1.2.3 Conclusion--The reviewer concludes that the applicant should comply with the trending requirements or meet the time limit values specified in the Code and that this should be sufficient to demonstrate proper valve operability. The reviewer concludes that the alternate testing proposal would not give reasonable assurance of valve operability required by the Code and, therefore, relief should not be granted.

3.6.2 Rapid Acting Valves

3.6.2.1 Relief Request. The applicant has requested relief from the power operated valve trending requirements of Section XI, Paragraph IWV-3417(a), for all rapid-acting, power operated valves whose function is safety related and proposed to apply a maximum stroke time limit of 2 seconds to all rapid-acting, power operated valves; i.e., those valves with normal stroke times of less than 2 seconds.

3.6.2.1.1 Applicant's Basis for Requesting Relief--These solenoid-operated valves have very short stroke times and are classified as "rapid-acting" valves. Accurate measurement of stroke time is not practical. In addition, stroke times may vary significantly due to system pressure and/or temperature changes from one test to another. As an alternative, these valves will be required to be full-stroked and timed to the nearest second quarterly. Acceptance of the test will be based only on the stroke time limit (not to exceed 2 seconds) and not on the "50%" criteria of IWV-3417.

3.6.2.1.2 Evaluation--The reviewer agrees with the applicant's proposal to place a 2 second maximum limit on stroke time for rapid acting power operated valves. This proposal is consistent with the NRC staff position on rapid acting valves discussed in Appendix A, Section 8 of this report.

3.6.2.1.3 Conclusion--The reviewer concludes that the applicant's proposal to assign a maximum stroke time limit of 2 seconds on their rapid acting power operated valves is in accordance with the NRC staff's position on rapid acting valves and should be sufficient to determine proper valve operability. The reviewer concludes that this alternate criteria proposed will give reasonable assurance of valve operability as required by the Code and, therefore, relief should be granted.

3.6.3 Category A/C Valves

3.6.3.1 Relief Request. The applicant has requested relief from exercising the following valves in accordance with the requirements of Section XI, Paragraph IWV-3522(a) and proposed to verify operability on a refueling outage frequency in accordance with the requirements of 10 CFR 50, Appendix J.

System	Valve Identification	Function
Chemical and Volume	CV-0034A	RCP 1A Seal Injection Check
Control System (CVCS)	CV-0034B	RCP 1B Seal Injection Check
	CV-0034C	RCP 1C Seal Injection Check
	CV-0034D	RCP 1D Seal Injection Check
	CV-0026	Charging Check
Instrument Air System (IA)	IA-0541	IA to Containment Check
Reactor Coolant System (RCS)	XRC-0046	Reactor Makeup Water to Pressurizer Relief Tank (PRT) Check
Component Cooling System (CC)	CC-0319	CCW to RCP Check
Essential Chilled Water System (CH)	CH-0255	CHW to Containment Check

3.6.3.1.1 Applicant's Basis for Requesting Relief--Due to plant design, it is not practical to verify by any positive means, either directly or indirectly, the operability of these normally open check valves per the requirements of IWV-3522(a). As an alternative, valve closure will be verified during LLRT activities performed each refueling outage in accordance with 10 CFR 50 Appendix J.

3.6.3.1.2 Evaluation--The reviewer agrees that, due to plant design, the only method available to verify closure (their only safety related function) of the valves listed in Section 3.6.3.1 is leak testing. These valves are located inside containment and are not equipped with position indication.

3.6.3.1.3 Conclusion--The reviewer concludes that relief should be granted from the exercising interval requirements of Section XI for these valves and that the proposed alternate testing of verifying valve closure during the performance of leakrate testing at refueling outages should give reasonable assurance of valve operability as required by the Code and, therefore, is acceptable.

APPENDIX A

NRC STAFF POSITIONS AND GUIDELINES

1. Full-Stroke Exercising of Check Valves.

The NRC's position was stated to the applicant that check valves whose safety function is to open are expected to be full-stroke exercised. Since the disk position is not always observable, the NRC staff position is that verification of the maximum flow rate through the check valve identified in any of the plant's safety analyses would be an adequate demonstration of the full-stroke requirement. Any flow rate less than this will be considered partial-stroke exercising unless it can be shown that the check valve's disk position at the lower flow rate would permit maximum flow required through the valve. It is the NRC staff's position that this reduced flow rate method of demonstrating full-stroke capability is the only test that requires measurement of the differential pressure across the valve.

2. Valves Identified for Cold Shutdown Exercising

The Code permits valves to be exercised during cold shutdowns where it is not practical to exercise during plant operation, and these valves are specifically identified by the applicant and are full-stroke exercised during cold shutdowns; therefore, the applicant is meeting the requirements of the ASME Code, Paragraphs IWV-3412 and 3522. Since the applicant is meeting the requirements of the ASME Code, it is not necessary to grant relief; however, during the review of the applicant's IST program, the reviewer verifies that it is not practical to exercise these valves during power operation and that the applicant's basis is valid.

It should be noted that the NRC differentiates, for valve testing purposes, between the cold shutdown mode and the refueling mode. That is, for valves identified for testing during cold shutdowns, it is expected that the tests will be performed both during cold shutdowns and each refueling outage. However, when relief is granted to perform tests on a refueling outage frequency, testing is expected only during each refueling outage. In addition, for extended outages, tests being performed are expected to be maintained as closely as practical to the Code-specified frequencies.

3. Conditions for Valve Testing During Cold Shutdown

Cold shutdown testing of valves identified by the applicant is acceptable when the following conditions are met:

a. The applicant is to commence testing as soon as the cold shutdown condition is achieved, but not later than 48 hours after shutdown, and continue until complete or the plant is ready to return to power.

b. Completion of all valve testing is not a prerequisite to return to power.

c. Any testing not completed during one cold shutdown should be performed during any subsequent cold shutdowns starting from the last test performed at the previous cold shutdown.

d. For planned cold shutdowns, where ample time is available and testing all the valves identified for the cold shutdown test frequency in the IST program will be accomplished, exceptions to the 48 hours may be taken.

4. Category A Valve Leak Test Requirements for Containment Isolation Valves (CIVs)

All containment isolation valves that are Appendix J, Type C, leak tested should be included in the IST program as Category A or A/C valves. The NRC has concluded that the applicable leak test procedures and requirements for containment isolation valves are determined by 10 CFR 50, Appendix J. Relief from Paragraphs IWV-3421 through 3425 (1983 Edition through Summer 1983 Addenda) for containment isolation valves presents no safety problem since the intent of these paragraphs is met by Appendix J requirements, however, the applicant must comply with the Analysis of Leakage Rates and Corrective Action Requirements Paragraphs IWV-3426 and 3427 (1983 Edition through Summer 1983 Addenda). Based on the considerations discussed above, the NRC staff has concluded that the alternate testing proposed will give reasonable assurance of valve leak-tight integrity as required by the Code and that the relief thus granted will not endanger life or property or the common defense and security of the public.

5. Application of Appendix J Testing to the IST Program

The Appendix J review for this plant is completely separate from the IST program review. However, the determinations made by that review are directly applicable to the IST program. The applicant has agreed that, should the Appendix J program be amended, they will amend their IST program accordingly.

6. Safety-Related Valves

This review was limited to valves whose function is safety-related. Valves whose function is safety-related are defined as those valves that are needed to mitigate the consequences of an accident and/or to shut down the reactor to the cold shutdown conditions and to maintain the reactor in a cold shutdown condition. Valves in this category would typically include certain ASME Code Class 1, 2, and 3 valves and could include some non-Code class valves. It should be noted that the applicant may have included valves whose function is not safety-related in their IST program as a decision on their part to expand the scope of their program.

7. Active Valves

The NRC staff position is that active valves are those for which changing position may be required to shut down a reactor to the cold shutdown condition or in mitigating the consequences of an accident.

Included are valves which respond automatically to an accident signal and valves which may be optionally utilized but are subject to plant operator actions, such as valves utilized to establish long term recirculation following a LOCA.

8. Rapid-Acting Power Operated Valves

The NRC staff has identified rapid-acting power operated valves as those which stroke in 2 seconds or less. Relief from the trending requirements of Section XI (Paragraph IWV-3417(a), 1983 Edition through Summer 1983 Addenda) presents no safety concerns for these valves since variations in stroke times will be affected by slight variations in the response times of the personnel performing the tests. However, the staff does require that the applicant assign a maximum limiting stroke time of 2 seconds to these valves in order to obtain this Code relief.

9. Pressurizer Power Operated Relief Valves

The NRC has adopted the position that the pressurizer power operated relief valves (PORVs) should be included in the IST program as Category B valves and tested to the requirements of Section XI. However, since the PORVs have shown a high probability of sticking open and are not needed for overpressure protection during power operation, the NRC has concluded that routine exercising during power operation is "not practical" and, therefore, not required by IWV-3410.

The PORVs' function during reactor startup and shutdown is to protect the reactor vessel and coolant system from low-temperature overpressurization conditions and should be exercised prior to initiation of system conditions for which vessel protection is needed.

The following test schedule is required:

a. Full-stroke exercising should be performed at each[a] cold shutdown or, as a minimum, once each refueling cycle.

b. Stroke timing should be performed at each cold shutdown, or as a minimum, once each refueling cycle.

c. Fail-safe actuation testing should be performed at each cold shutdown.

d. The PORV block valves should be included in the IST program and tested quarterly to provide protection against a small break LOCA should a PORV fail open.

The applicant has included the PORVs (PCV-0655A and 0656A) in the IST program as Category A valves and the PORV block valves (MOV-0001A and 0001B) as Category B valves and is exercising them in accordance with the above guidelines.

10. Valves Which Perform a Pressure Boundary Isolation Function

The following valves meet the criteria for pressure boundary isolation valves and have been included in the IST program as Category A or A/C and are leak rate tested in accordance with the requirements of Section XI.

MOV-0060A	-	
MOV-0060B	-	RHR Pump Suction Checks
MOV-0060C	-	
MOV-0061A	-	
MOV-0061B	-	RHR Pump Discharge Checks
MOV-0061C	-	

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a. The staff position described in Item A.3 regarding cold shutdown testing is not applicable to the PORVs; however, in case of frequent cold shutdowns, testing of the PORVs is not required more often than each three months.

XRH-0020A	-	
XRH-0020B	-	RHR to Cold Leg Injection Valves
XRH-0020C	-	
XRH-0032A	-	
XRH-0032B	-	RHR to Cold Leg Checks
XRH-0032C	-	
XSI-0007A	-	
XSI-0007B	-	HHSI Pump Cold Leg Checks
XSI-0007C	-	
XSI-0009A	-	
XSI-0009B	-	HHSI Pump Hot Leg Checks
XSI-0009C	-	
XSI-0010A	-	
XSI-0010B	-	HHSI Pump Hot Leg Checks
XSI-0010C	-	
XSI-0038A	-	
XSI-0038B	-	SI Cold Leg Checks
XSI-0038C	-	
XSI-0046A	-	
XSI-0046B	-	SIS Accumulator Checks
XSI-0046C	-	

APPENDIX B

VALVES TESTED DURING COLD SHUTDOWNS

The following are Category A, B, and C valves that meet the exercising requirements of the ASME Code, Section XI, and are not full-stroke exercised every three months during plant operation. These valves are specifically identified by the owner in accordance with Paragraph IWV-3412 and 3522 and are full-stroke exercised during cold shutdowns and refueling outages. All valves in this Appendix have been evaluated and the reviewer agrees with the applicant that testing these valves during power operation is not practical due to the valves type, location or system design. These valves should not be exercised during power operation. These valves are listed below and grouped according to the system in which they are located.

System	Valve Identification	Function
Auxiliary Feedwater	MOV-0048	AFW pump No. 11 discharge stop check
	MOV-0065	AFW pump No. 12 discharge stop check
	MOV-0085	AFW pump No. 13 discharge stop check
	MOV-0019	AFW pump No. 14 discharge stop check
	AF-0119	AFW to SG 1A check
	AF-0120	AFW to SG 1B check
	AF-0121	AFW to SG 1C check
	AF-0122	AFW to SG 1D check
Chemical and Volume Control	MOV-0113A	VCT outlet isolation
	MOV-0112A	VCT outlet isolation
	MOV-0033A	RCP 1A seal injection isolation
	MOV-0033B	RCP 1B seal injection isolation
	MOV-0033C	RCP 1C seal injection isolation
	MOV-0033D	RCP 1D seal injection isolation
	MOV-0077	RCP seal injection return isolation
	MOV-0079	RCP seal injection return isolation
	CV-0224	RWST to charging pump suction
	MOV-0113B	
	MOV-0112C	
	FCV-0205	Charging flow control
	MOV-0025	Charging isolation
	LV-3119	Auxiliary pressurizer spray control
	CV-0009	Auxiliary pressurizer spray check
	CV-0338	Boric acid transfer pump 1A discharge check
	CV-0349	Boric acid transfer pump 1B discharge check
	CV-0334	Boric acid gravity feed check
	CV-0217	Boric acid transfer to charging pump suction check
	LCV-0465	Letdown isolation
	LCV-0468	Letdown isolation
	MOV-0023	Letdown isolation
	MOV-0024	Letdown isolation
	CV-0001	Normal charging check
	CV-0002	Normal charging check

System	Valve Identification	Function
Chemical and Volume Control	CV-0004	Alternate charging check
	CV-0005	Alternate charging check
	MOV-0003	Normal charging isolation
	MOV-0006	Alternate charging isolation
Component Cooling Water (CCW)	MOV-0235	CCW to nonnuclear safety loop isolation
	MOV-0236	CCW to nonnuclear safety loop isolation
Essential Chilled Water (CHW)	MOV-0254	CHW to containment isolation
	MOV-0268	CHW from containment isolation
	MOV-0269	CHW from containment isolation
Feedwater	FV-7151	Feedwater regulator bypass
	FV-7152	Feedwater regulator bypass
	FV-7153	Feedwater regulator bypass
	FV-7154	Feedwater regulator bypass
	FV-7189	Feedwater to auxiliary feedwater warmup
	FV-7190	Feedwater to auxiliary feedwater warmup
	FV-7191	Feedwater to auxiliary feedwater warmup
	FV-7192	Feedwater to auxiliary feedwater warmup
	FV-7141	Feedwater isolation
	FV-7142	Feedwater isolation
	FV-7143	Feedwater isolation
	FV-7144	Feedwater isolation
Instrument Air (IA)	FV-8565	IA to containment isolation
Main Steam	PV-7411	Main steam line 1 PORV
	PV-7421	Main steam line 2 PORV
	PV-7431	Main steam line 3 PORV
	PV-7441	Main steam line 4 PORV
	PV-7414	Main steam isolation valve
	PV-7424	Main steam isolation valve
	PV-7434	Main steam isolation valve
	PV-7444	Main steam isolation valve
Reactor Coolant	PCV-0655A	PORV
	PCV-0656A	PORV
Residual Heat Removal (RHR)	MOV-0060A	RHR pump 1A suction isolation
	MOV-0060B	RHR pump 1B suction isolation
	MOV-0060C	RHR pump 1C suction isolation
	MOV-0061A	RHR pump 1A suction isolation
	MOV-0061B	RHR pump 1B suction isolation
	MOV-0061C	RHR pump 1C suction isolation
	XRH-0065A	RHR pump 1A discharge check
	XRH-0065B	RHR pump 1B discharge check
	XRH-0065C	RHR pump 1C discharge check
	XRH-0020A	RHR 1A to hot leg check

System	Valve Identification	Function
Residual Heat Removal (RHR)	XRH-0020B	RHR 1B to hot leg check
	XRH-0020C	RHR 1C to hot leg check
	XRH-0032A	RHR 1A to cold leg check
	XRH-0032B	RHR 1B to cold leg check
	XRH-0032C	RHR 1C to cold leg check
	HCV-864	RHR 1A heat exchanger outlet
	HCV-865	RHR 1B heat exchanger outlet
	HCV-866	RHR 1C heat exchanger outlet
	FCV-851	RHR 1A heat exchanger bypass
	FCV-852	RHR 1B heat exchanger bypass
	FCV-853	RHR 1C heat exchanger bypass
Reactor Containment Building Purge	MOV-0007	Normal purge supply isolation
	MOV-0008	Normal purge supply isolation
	MOV-0009	Normal purge exhaust isolation
	MOV-0010	Normal purge exhaust isolation
	MOV-0001	Supplementary purge supply isolation
	MOV-0003	Supplementary purge supply isolation
	MOV-0005	Supplementary purge exhaust isolation
	MOV-0006	Supplementary purge exhaust isolation

APPENDIX C

The ISI Boundary Drawings listed below were used during the course of this review.

System	Drawing No.	Revision
Auxiliary Feedwater	5S149F00024	6
Post Accident Sampling	5Z549Z47501	2
Breathing Air	5Q129F05044	5
Component Cooling Water	5R209F05017	5
Component Cooling Water	5R209F05018	6
Component Cooling Water	5R209F05019	5
Component Cooling Water	5R209F05020	5
Component Cooling Water	5R209F05021	4
Reactor Containment Building Chilled Water	5V149V00021	5
HVAC-Essential Chilled Water	5V119V10001	7
HVAC-Essential Chilled Water	5V119V10002	5
Containment Hydrogen Monitoring	5Z169200046	5
Containment Spray	5N109F05037	7
Chemical and Volume Control	5R179F05005	6
Chemical and Volume Control	5R179F05006	3
Chemical and Volume Control	5R179F05007	6
Chemical and Volume Control	5R179F05009	6
Demineralized Water Distribution System RCB, FHB, and MEAB	5S199F05034	4
Radioactive Vent and Drain System Sump Pumps	5Q069F05030	4
Essential Cooling Water	5R289F05038	5
Essential Cooling Water	5R289F05039	5
Spent Fuel Pool Cooling and Cleanup	5R219F05028	6
Fuel Handling, IVC, ELEC. AUX. Bldg., Containment Bldg., and Deluge Valve House No. 11 Fire Protection	5Q279F05047	4
Feedwater	5S139F00063	6
Reactor Containment Bldg. Normal Purge Subsystem	5V149V00018	4
Reactor Containment Bldg. Supplementary Purge Subsystem	5V149V00019	5
Fuel Handling Bldg. and Reactor Containment Bldg. Instrument Air	5Q119F05040	5
Main Steam	5S109F00016	6
Reactor Coolant Pump Oil Changing	5R379F05042	3
Primary Sampling	5Z329Z00045	2
Heating, Ventilating, and Air Conditioning Reactor Containment Bldg. System Composite	5V149V00017	5
RCS Primary Coolant Loop	5R149F05001	4
RCS Pressurizer	5R149F05003	3
RCS Pressurizer Relief Tank	5R149F05004	3
RCS Vacuum Degassing	5R349F05046	3
Residual Heat Removal	5R169F20000	4
Reactor Makeup Water	5R279F05033	4
Fuel Handling Bldg. and Reactor Containment Bldg. Service Air	5Q109F05041	2
Steam Generator Blowdown	5S209F20001	5
Safety Injection	5N129F05013	4

System	Drawing No.	Revision
Safety Injection	5N129F05014	4
Safety Injection	5N129F05015	4
Safety Injection	5N129F05016	4
Steam Generator Sludge Lancing and Chemical Cleaning	5S208F05057	3
Liquid Waste Processing	5R309F05022	3

APPENDIX D

IST PROGRAM ANOMALIES IDENTIFIED DURING THE REVIEW

Inconsistencies and omissions in the applicant's program noted during the course of this review are summarized below. The applicant should resolve these items in accordance with the evaluations, conclusions, and guidelines presented in this report.

1. The applicant has proposed to test the RHR pumps quarterly during plant operation and measure all parameters with the exception of pump inlet pressure and differential pressure (see Section 2.2.1 of this report). The reviewer agrees that since there will be very little variation in pump inlet pressure and that the applicant is utilizing pump outlet pressure to determine pump hydraulic condition that this should be sufficient testing during power operation, however, the applicant should measure all Code required parameters on a cold shutdown frequency when these measurements can be taken.

2. The applicant has requested relief from the corrective action requirements of Section XI, Paragraph IWV-3417(a) for all valves that require stroke timing and can only be exercised during cold shutdowns (see Section 3.6.1.2 of this report). The reviewer feels that continued plant operation should not be permitted when these valves are known to be operating in a degraded condition.

3. The applicant has requested relief from exercising valves FCV-0551, 0552, 0553, and 0554, feedwater regulator valves (see Section 3.3.1.1 of this report) in accordance with the requirements of Section XI, Paragraph IWV-3412 and 3414 and proposed to verify valve operability by partial-stroke exercising these valves during plant operation on a nonspecified frequency and full-stroke exercising them on a cold shutdown frequency. The reviewer agrees with the applicant that these valves can only be full-stroke exercised during cold shutdown, however, the reviewer believes that the applicant has the ability to partial-stroke exercise these valves at least quarterly during power operation.

APPENDIX E

VALVES TESTED DURING COLD SHUTDOWN - DETAILS

The following are Category A, B, and C valves that meet the exercising requirements of the ASME Code, Section XI, and are not full-stroke exercised every three months during plant operation. These valves are specifically identified by the owner in accordance with Paragraph IWV-3412 and 3522 and are full-stroke exercised during cold shutdowns and refueling outages. All valves in this Appendix have been evaluated and the reviewer agrees with the applicant that testing these valves during power operation is not possible due to the valve type and location or system design. These valves should not be exercised during power operation. These valves are listed below and grouped according to the system in which they are located.

1. AUXILIARY FEEDWATER SYSTEM

1.1 Category B Valves

The auxiliary feedwater pump discharge stop check valves MOV-0048, 0065, 0085, and 0019 are stop check valves with motor operators. The motor operator may be safely stroked at power; however, the stop check valve disk can only be exercised (full-stroke) by directing auxiliary feedwater flow into the steam generators. Power operation initiation of auxiliary feedwater would result in thermal shock to the steam generators and reactor plant power transients. The valve motor operators will be stroked and timed quarterly and the stop check valves disks will be full-stroke exercised during cold shutdowns and refueling outages.

1.2 Category C Valves

The auxiliary feedwater to steam generator check valves AF-0119, 0120, 0121, and 0122 cannot be exercised during power operation because initiation of auxiliary feedwater would result in thermal shock to the steam generators and reactor plant power transients. These check valves will be full-stroke exercised during cold shutdowns and refueling outages.

2. CHEMICAL AND VOLUME CONTROL SYSTEM

2.1 Category A Valves

The reactor coolant pump seal injection isolation valves MOV-0033A, 0033B, 0033C, 0033D, 0077, and 0079 cannot be exercised during power operation as the produced transients would affect seal injection flow to the reactor coolant pumps and could result in pump seal damage. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Letdown isolation valves MOV-0023 and 0024 and charging isolation valve MOV-0025 cannot be exercised during power generation as a failure in the closed position could result in a plant shutdown due to loss of pressurizer level control. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

2.2 Category B Valves

Letdown isolation valves LCV-0465 and 0468 and charging flow control valve FCV-0205 cannot be exercised during power operation as a failure in the closed position could result in a plant shutdown due to loss of pressurizer level control. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Volume control tank outlet valves MOV-0113A and 0112A cannot be exercised during power operation as the operability testing of these valves would cause a loss of system function. Subsequent utilization of other suction sources (RWST or boric acid transfer system) would affect reactivity control possibly requiring a plant shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Refueling water storage tank to charging pump suction valves MOV-0113B and MOV-0112C cannot be exercised during power operation as the resultant flow path would cause concentrated boric acid injection into the reactor coolant system with attendant undesirable power changes. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Normal charging isolation valve MOV-0003 and alternate charging isolation valve MOV-0006 cannot be exercised during power operation as alternating charging headers would cause thermal shock and possible reactor coolant system boundary charging nozzle damage. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Auxiliary pressurizer spray control valve LV-3119 cannot be exercised during power operation as this would introduce relatively cold spray water into the pressurizer creating undesirable transients. This valve will be full-stroke exercised during cold shutdowns and refueling outages.

2.3 Category C Valves

Refueling water storage tank to charging pump suction valve CV-0224 cannot be exercised during power operation as the resultant flow path would cause concentrated boric acid injection into the reactor coolant system with attendant undesirable power changes. This valve will be full-stroke exercised during cold shutdowns and refueling outages.

Auxiliary pressurizer spray check valve CV-0009 cannot be exercised during power operation as this would introduce relatively cold spray water into the pressurizer creating undesirable transients. This valve will be full-stroke exercised during cold shutdowns and refueling outages.

Normal charging check valves CV-0001 and 0002 and alternate charging check valves CV-0004 and 0005 cannot be exercised during power operation as alternating charging headers would cause thermal shock and possible reactor coolant system boundary charging nozzle damage. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Boric acid transfer pump 1A discharge check valve CV-0338, boric acid transfer pump 1B discharge check valve CV-0349, boric acid gravity feed check valve CV-0334 and boric acid transfer to charging pump suction check valve CV-0217 cannot be exercised during power operation as this would result in injection of concentrated boric acid into the reactor coolant system via the operating charging pump(s) creating an undesirable power transient and possible plant shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

3. COMPONENT COOLING WATER SYSTEM

3.1 Category B Valves

Component cooling water to nonnuclear safety loop isolation valves MOV-0235 and 0236 cannot be exercised during power operation as this requires isolating normal letdown by closure of LCV-0465 or 0468 (both inaccessible during normal power operation) to prevent thermal shock to the letdown heat exchanger. Failure of either LCV-0465 or 0468 in the closed position could result in loss of normal pressurizer level control and plant shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

4. ESSENTIAL CHILLED WATER SYSTEM

4.1 Category A Valves

Essential chilled water containment isolation valves MOV-0254, 0268, and 0269 cannot be exercised during power operation as failure in the closed position would result in unacceptable containment temperatures and subsequent Technical Specification required plant shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

5. FEEDWATER SYSTEM

5.1 Category B Valves

Feedwater isolation valves FV-7141, 7142, 7143, and 7144 cannot be exercised during power operation as resultant steam generator feedwater isolation would cause an undesirable power transient and possible turbine and reactor trip. These valves will be partial-stroke exercised quarterly and full-stroke exercised during cold shutdowns and refueling outages.

Feedwater to auxiliary feedwater warm-up valves FV-7189, 7190, 7191, and 7192 cannot be exercised during power operation as injection of the cooler auxiliary feedwater lines water followed by the hotter main feedwater would cause thermal shock and possible steam generator boundary auxiliary feedwater nozzle damage. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Feedwater regulator bypass valves FV-7151, 7152, 7153, and 7154 cannot be exercised during power operation without isolating or perturbing feedwater flow to the steam generators, which would cause undesirable power transients and possible turbine and reactor trip. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

6. INSTRUMENT AIR SYSTEM

6.1 Category A Valves

Instrument air to containment isolation valve FV-8565 cannot be exercised during power operation as isolation of instrument air would cause a plant shutdown. This valve will be full-stroke exercised during cold shutdowns and refueling outages.

7. MAIN STEAM SYSTEM

7.1 Category B Valves

Steam Generator power operated relief valves PV-7411, 7421, 7431, and 7441 cannot be exercised during power operation as a failure to close would cause undesirable power transients and possible plant shutdowns. These valves will be full-stroke exercised during cold shutdown and refueling outages.

Main steam isolation valves FSV-7414, 7424, 7434, and 7444 cannot be exercised during power operation as closure of these valves will cause a plant shutdown. These valves will be partial-stroke exercised quarterly and full-stroke exercised during cold shutdowns and refueling outages.

8. REACTOR COOLANT SYSTEM

8.1 Category A Valves

Power operated relief valves PCV-0655A and 0656A cannot be exercised during power operation due to the resultant undesirable reactor coolant system pressure and pressurizer level transients and possible subsequent reactor trip. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

9. RESIDUAL HEAT REMOVAL SYSTEM

9.1 Category A Valves

Residual heat removal pump suction isolation valves MOV-0060A, 0060B, 0060C, 0061A, 0061B, and 0061C cannot be exercised during power operation due to a reactor coolant system pressure interlock (i750 psig). These valves will be full-stroke exercised during cold shutdowns and refueling outages.

9.2 Category A/C Valves

Residual heat removal hot leg check valves XRH-0020A, 0020B, and 0020C and residual heat removal cold leg check valves XRH-0032A, 0032B, and 0032C cannot be exercised during power operation because the residual heat removal pumps cannot overcome reactor coolant system pressure to allow flow through these valves. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

9.3 Category B Valves

Residual heat removal heat exchanger's outlet valves HCV-846, 865, and 866 and residual heat removal heat exchanger's bypass valves FCV-851, 852, and 853 are inaccessible during power operation and stroke exercising and timing of these valves requires lifting electrical leads to obtain repeatable stroke times as these valve are normally controlled by a controller and not a hand switch. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

10. REACTOR CONTAINMENT BUILDING PURGE SYSTEM

10.1 Category A Valves

Normal purge supply isolation valves MOV-0007 and 0008 and normal purge exhaust isolation valves MOV-0009 and 0010 cannot be exercised during power operation because of the Technical Specification requirement to be sealed closed. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

Supplementary purge supply isolation valves MOV-0001 and 0003 and supplementary purge exhaust isolation valves MOV-0005 and 0006 cannot be exercised during power operation as failure in the open position would violate containment integrity and necessitate a plant shutdown. These valves will be full-stroke exercised during cold shutdowns and refueling outages.

APPENDIX R

CONFORMANCE TO REGULATORY GUIDE 1.97
SOUTH TEXAS PROJECT, UNIT NOS. 1 and 2

TECHNICAL EVALUATION REPORT

CONFORMANCE TO REGULATORY GUIDE 1.97
SOUTH TEXAS PROJECT, UNIT NOS. 1 and 2

Docket Nos. 50-498/50-499

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ABSTRACT

This EG&G Idaho, Inc., report reviews the submittals for Regulatory Guide 1.97, Revision 2, for Unit Nos. 1 and 2 of the South Texas Project and identifies areas of nonconformance to the regulatory guide. Exceptions to Regulatory Guide 1.97 are evaluated and those areas where sufficient basis for acceptability is not provided are identified.

Docket Nos. 50-498 and 50-499

FOREWORD

This report is supplied as part of the "Program for Evaluating Licensee/Applicant Conformance to RG 1.97," being conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Regulatory Regulation, Division PWR Licensing-A, by EG&G Idaho, Inc., NRR and I&E Support Branch.

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Docket Nos. 50-498 and 50-499

CONTENTS

CONFORMANCE TO REGULATORY GUIDE 1.97
SOUTH TEXAS PROJECT, UNIT NOS. 1 and 2

1. INTRODUCTION

On December 17, 1983, Generic Letter No. 82-33 (Reference 1) was issued by D. G. Eisenhut, Director of the Division of Licensing, Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses and holders of construction permits. This letter included additional clarification regarding Regulatory Guide 1.97, Revision 2 (Reference 2) relating to the requirements for emergency response capability. These requirements have been published as Supplement No. 1 to NUREG-0737, "TMI Action Plant Requirements" (Reference 3).

Houston Lighting and Power Company, the applicant for the South Texas Project, Unit Nos. 1 and 2, provided a response to Section 6.2 of the generic letter on September 25, 1984 (Reference 4). Additional information was submitted on March 26, 1986 (Reference 5), and on May 23, 1986 (Reference 6).

This report provides an evaluation of these submittals.

2. REVIEW REQUIREMENTS

Section 6.2 of NUREG-0737, Supplement No. 1, sets forth the documentation to be submitted in a report to NRC describing how the applicant complies with Regulatory Guide 1.97 as applied to emergency response facilities. The submittal should include documentation that provides the following information for each variable shown in the applicable table of Regulatory Guide 1.97.

1. Instrument range

2. Environmental qualification

3. Seismic qualification

4. Quality assurance

5. Redundance and sensor location

6. Power supply

7. Location of display

8. Schedule of installation or upgrade.

The submittal should identify deviations from the regulatory guide and provide supporting justification or alternatives.

Subsequent to the issuance of the generic letter, the NRC held regional meetings in February and March 1983, to answer licensee and applicant questions and concerns regarding the NRC policy on this subject. At these meetings, it was noted that the NRC review would only address exceptions taken to Regulatory Guide 1.97. Where licensees or applicants explicitly state that instrument systems conform to the regulatory guide it was noted that no further staff review would be necessary. Therefore, this report only addresses exceptions to Regulatory Guide 1.97. The following evaluation is an audit of the applicant's submittals based on the review policy described in the NRC regional meetings.

3. EVALUATION

The applicant provided a response to Section 6.2 of NRC Generic Letter 82-33 on September 25, 1984. Additional information was submitted on March 26, 1986, and on May 23, 1986. This evaluation is based on these submittals.

3.1 Adherence to Regulatory Guide 1.97

The applicant states that their submittals provide a detailed account of the conformance of the South Texas Project, Unit Nos. 1 and 2, to the recommendations of Revision 2 of Regulatory Guide 1.97. The applicant further states that the information provided in their submittal meets the requirements of Supplement No. 1 to NUREG-0737, Section 6. Therefore, we conclude that the applicant has provided an explicit commitment on conformance to Regulatory Guide 1.97. Exceptions to and deviations from the regulatory guide are noted in Section 3.3.

3.2 Type A Variables

Regulatory Guide 1.97 does not specifically identify Type A variables, i.e., those variables that provide the information required to permit the control room operator to take specific manually controlled safety actions. The applicant classifies the following instrumentation as Type A.

1. Reactor coolant system (RCS) pressure
2. RCS hot leg water temperature
3. RCS cold leg water temperature
4. Steam generator level (wide range)
5. Steam generator level (narrow range)
6. Pressurizer level
7. Containment pressure
8. Steamline pressure
9. Refueling water storage tank (RWST) level
10. Containment water level (wide range)
11. Containment water level (narrow range)
12. Auxiliary feedwater storage tank level
13. Auxiliary feedwater flow

14. Containment radiation level (high range)

15. RCS pressure

16. Steam generator blowdown radiation monitor

17. Steamline radiation monitor

18. Core exit temperature

19. RCS subcooling.

Except as noted in Section 3.3, the above variables meet the Category 1 recommendations consistent with the requirements for Type A variables.

3.3 Exceptions to Regulatory Guide 1.97

The applicant identified deviations and exceptions from Regulatory Guide 1.97. These are discussed in the following paragraphs.

3.3.1 Range Requirement Deviation

In Reference 4, the applicant indicated that the following variables conform to the range recommended by Regulatory Guide 1.97. However, the range provided for each variable was listed as 0 to 100 percent of span. Based on this information we were unable to determine that the range meets the regulatory guide recommendation. Reference 5, provided the ranges monitored and Reference 6 provided justification for those that deviated from the regulatory guide recommendations. These ranges are evaluated below.

1. Steam generator level (wide range)
   (from tube sheet to separators)

In Reference 5, the applicant states that the range provided for this variable monitors from 12 inches above the tube sheet to 4 inches above the separator. In Reference 6, the applicant states that there is very little heat removal capacity available below the lower tap. In addition, the location is conservative since the operator considers a level at the lower tap as empty.

At 12 inches above the tube sheet, the steam generator is essentially empty. Therefore, this deviation is minor with respect to the overall range and system accuracy. The existing range is adequate to monitor this variable during all accident and post-accident conditions.

2. Steam generator level (narrow range)
   (no specific requirement)

In References 5 and 6, the applicant provided the range of the narrow range instrumentation for this variable (425 inches above the tube sheet to

4 inches above the top of the separators). Regulatory Guide 1.97 does not require a specific range. We find the provided range acceptable for its design functions.

3. Pressurizer level
(bottom to top)

In Reference 5, the applicant states that the total volume of the pressurizer is 2100 cubic feet. The level instrumentation provided monitors from 147.7 cubic feet from the bottom to 2002 cubic feet. In Reference 6, the applicant states that they monitor most of the linear portion of the tank. The applicant considers this conservative since the operator action is to prevent emptying or filling the pressurizer and there is, in fact, 147 cubic feet in the tank when 0 level is indicated and 98 cubic feet left in the tank when the indication is full.

Outside the supplied instrument range, in the hemispherical vessel ends, the volume to level ratio is not linear (approximately 12 percent of the total volume is not monitored). We find this deviation minor and, therefore, acceptable.

4. Refueling water storage tank
(top to bottom)

In Reference 6, the applicant states that the bottom tap is 1 foot above the tank bottom, with the centerline of the supply nozzle 3 feet above the tank bottom. The upper tap is in the overflow pipe, 32 feet 5 inches above the tank bottom. This range covers the maximum achievable volume of the tank.

We find this deviation minor with respect to the overall size of the tank. The existing instrumentation is adequate to monitor the operation of the storage tank during all accident and post-accident conditions. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

5. Auxiliary water storage tank
(top to bottom)

In Reference 6, the applicant states that the bottom tap is 6 inches above the tank bottom (at the centerline of the pump suction) and the upper tap is at the centerline of the tank overflow. This range covers the maximum achievable volume of the tank.

We find this deviation minor with respect to the overall size of the tank. The existing instrumentation is adequate to monitor the operation of the storage tank during all accident and post-accident conditions. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

6. Auxiliary feedwater flow
(0 to 110 design flow)

In Reference 5, the applicant states that instrumentation with a range of 0 to 700 gpm is provided for each of the physically separated auxiliary feedwater lines. In addition total auxiliary feedwater flow (0-2800 gpm) is displayed. We find this instrumentation acceptable for this variable.

7. Volume control tank level
(top to bottom)

In Reference 5, the applicant states that the total volume of the tank is 600 cubic feet. The lower instrument tap is at 72 cubic feet with the upper tap at 528 cubic feet. In Reference 6, the applicant states that the volume control tank level is used in the emergency operating procedures only for when the operator is returning the pressurizer level control to automatic. Level outside of the provided range would preclude this operation.

The existing range is adequate for the instrumentation to perform its function during any accident condition. Therefore, this is an acceptable deviation from Regulatory Guide 1.97.

8. Main feedwater flow
(0 to 110 percent design flow)

Reference 5 has provided the range of this instrumentation (0 to 5×10^6 lb/hr). This meets the recommendation of Regulatory Guide 1.97.

9. Containment spray flow
(0 to 110 percent design flow)

Reference 5 has provided the range of this instrumentation (0 to 3000 gpm). This meets the recommendation of Regulatory Guide 1.97.

10. Component cooling water flow to emergency safety features (ESF) system components
(0 to 110 percent design flow)

Reference 5 has provided the range of this instrumentation (pump discharge--0 to 20,000 gpm; reactor containment fan cooler--0 to 2500 gpm; and residual heat removal heat exchanger--0 to 7000 gpm). This meets the recommendation of Regulatory Guide 1.97.

11. Residual heat removal (RHR) system flow
(0 to 110 percent design flow)

Reference 5 has provided the range of this instrumentation (0 to 4000 gpm). This meets the recommendation of Regulatory Guide 1.97.

12. Unit vent flow
to 110 percent design flow)

Reference 5 has provided the range of this instrumentation (37,000 to 290,500 cfm. The upper limit of the range meets the recommendation of Regulatory Guide 1.97. The lower limit of the range is exceeded when any one vent fan is in operation. Therefore, we find the provided range acceptable.

3.3.2 RCS Soluble Boron Concentration

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 0 to 6000 ppm.

In Reference 5, the applicant states that the post-accident sampling system is sufficient to meet this recommendation.

This deviation goes beyond the scope of this review and is being addressed by the NRC as part of their review of NUREG-0737, Item II.B.3.

3.3.3 Reactor Coolant System Cold and Hot Leg Temperature

Revision 2 of Regulatory Guide 1.97 recommends instrumentation for these variables with ranges of 50 to 750°F. The applicant has supplied instrumentation for these variables with ranges from 0 to 700°F. The applicant presented no justification for these deviations.

Revision 3 of Regulatory Guide 1.97 (Reference 7) recommends a range of 50 to 700°F for these variables. The instrumentation supplied by the applicant meets this range. Therefore, the range supplied by the applicant for these variables is acceptable.

3.3.4 Core Exit Temperature

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 200°F to 2300°F. The applicant is installing instrumentation for this variable with a range of 100°F to 2200°F and has not identified this as a deviation.

This exception goes beyond the scope of this review and is being addressed by the NRC as part of their review of NUREG-0737, Item II.F.2.

3.3.5 Coolant Level in Reactor

Regulatory Guide 1.97 recommends instrumentation for this variable with a range from the bottom of the core to the top of the vessel. The applicant is installing instrumentation for this variable with a range that covers from the upper core support plate to the top of the vessel. The applicant has not identified this as a deviation.

This deviation goes beyond the scope of this review and is being addressed by the NRC as part of their review of NUREG-0737, Item II.F.2.

3.3.6 Containment Isolation Valve Position

Regulatory Guide 1.97 recommends Category 1 instrumentation for this variable. The applicant does not consider this to be a key variable to indicate whether plant safety functions are being accomplished. The applicant states that this variable is designated for monitoring a gross breach of the containment and is therefore designated as Category 2.

In Reference 5, the applicant states that containment valve status conforms to the Category 1 instrumentation criteria, except for redundant indication per valve. For isolation valves in series, a single indication on each valve is sufficient to satisfy the requirements of Regulatory Guide 1.97 when those indications are powered from different trains. From the information provided, we find that the applicant deviates from a strict interpretation of the Category 1 redundancy recommendation. Since redundant isolation valves are provided, we find that redundant indication per valve is not intended by the regulatory guide. Therefore, we find that the instrumentation provided for this variable is acceptable.

3.3.7 Radiation Level in Circulating Primary Coolant

The applicant indicates that radiation level measurements to indicate fuel cladding failure are provided by the post-accident sampling system, which is being reviewed by the NRC as part of their review of NUREG-0737, Item I.B.3.

Based on the alternate instrumentation provided by the applicant, we conclude that the instrumentation supplied for this variable is adequate and, therefore, acceptable.

3.3.8 Analysis of Primary Coolant (Gamma Spectrum)

In Reference 4, the applicant did not provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737 for this variable.

In Reference 5, the applicant states that the post-accident sampling system is used to provide a RCS sample for analysis (gamma spectrum). On-site laboratory instrumentation is used for the analysis.

The applicant deviates from Regulatory Guide 1.97 with respect to post-accident sampling capability. This deviation goes beyond the scope of this review and is being addressed by the NRC as part of their review of NUREG-0737, Item II.B.3.

3.3.9 Radiation Exposure Rate (Type C)

Regulatory Guide 1.97, Revision 2, recommends Category 2 instrumentation for this variable as an indication of breach. The applicant has provided Category 3 instrumentation.

Regulatory Guide 1.97, Revision 3, (Reference 7) eliminates this variable as an indication of breach. Therefore, the existing instrumentation is acceptable.

3.3.10 Radiation Exposure Rate (Type E)

Regulatory Guide 1.97, Revision 2, recommends Category 2 instrumentation for this variable. The applicant has provided Category 3 instrumentation.

Regulatory Guide 1.97, Revision 3, recommends Category 3 instrumentation for this variable. Therefore, the provided instrumentation is acceptable to monitor this variable.

3.3.11 Residual Heat Removal (RHR) Heat Exchanger Outlet Temperature

The applicant has supplied instrumentation for this variable with a range of 50 to 400°F. Regulatory Guide 1.97, Revision 2, recommends a range of 32 to 350°F and Revision 3 recommends a range of 40 to 350°F. The low end of the range deviates from both revisions of the regulatory guide.

This deviation is less than 3 percent of the current maximum recommended range. Considering instrument accuracy and the overall range, we consider this deviation minor and, therefore, acceptable.

3.3.12 Accumulator Tank Level and Pressure

In Reference 4, the applicant indicates conformance for accumulator tank pressure. However, a range of 0 to 700 psig has been supplied while the regulatory guide recommends a range of 0 to 750. In Reference 5, the licensee states that the maximum pressure allowed by their Technical Specifications is between 586 and 679 psig. In addition to this, a safety valve with a setting of 700 psig is installed on each accumulator. Based on this justification, we find the provided range acceptable.

In Reference 4, the applicant indicates that there is no level indication provided for this variable. The applicant states that accumulator pressure and valve position indication provide adequate status of the accumulators. In Reference 5, the applicant states that Category 3 level indication is provided with a range from 59 to 64 percent of the tank volume. The applicant states that this is considered backup instrumentation and that this range is adequate to maintain the level within the technical specification limits and to indicate any discharge check valve back leakage.

The applicant considers the Category 2 pressure instrumentation to be the key variable for determination of accumulator discharge. Therefore, we find the narrow range level instrumentation acceptable.

3.3.13 Accumulator Isolation Valve Position

In Reference 4, the applicant did not provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737. In Reference 5, the applicant provided the required information and the instrumentation meets the recommendations of Regulatory Guide 1.97.

3.3.14 Boric Acid Charging Flow

The applicant does not have instrumentation for this variable. The applicant states that the units do not have boric acid charging flow as a post-accident safety injection system. Refueling water storage tank (RWST) level, high head safety injection (HHSI) flow, low head safety injection (LHSI) flow, containment water level, and emergency core cooling system (ECCS) valve status are the safety injection variables monitored.

Because this is not a safety injection flow at this station, we find that this variable is not applicable.

3.3.15 Reactor Coolant Pump Status

Regulatory Guide 1.97 recommends Category 3 motor current instrumentation to monitor this variable. In Reference 4, the applicant stated that on/off indication, that except for environmental qualification meets Category 2 requirements, is provided for this variable. In Reference 5, the applicant states that reactor coolant pump motor current indication is available in the control room for each pump. This meets the recommendations of Regulatory Guide 1.97 and is acceptable.

3.3.16 Pressurizer Heater Status

Regulatory Guide 1.97 recommends electric current indication to monitor this variable. In Reference 4, the applicant describes open/closed indication for the heater circuit breakers. The applicant states that heater circuit breaker position was selected for determining pressurizer heater status due to hardware considerations. In Reference 6, the applicant states that the pressurizer heaters are not required for response to an accident and have never been identified as safety-related equipment. The applicant further states that a heater group is capable of drawing 431 kW. Technical specifications consider the heaters operational if the quarterly check shows a minimum of 175 kW of heater capacity. The applicant states that it is unreasonable to assume that the capacity of the heaters would be degraded below 175 kW after an accident. The applicant also states that the safety grade charging or high head safety injection pumps are available as a means of pressure control if the heaters are not functioning.

We find this justification acceptable. Since the quarterly surveillance checks required by the plant technical specifications ensure sufficient heater capacity, we find the circuit breaker position indication provided by the applicant adequate to monitor this variable.

3.3.17 Quench Tank Level

Quench Tank Temperature
Quench Tank Pressure

In Reference 4, the applicant did not provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737. In Reference 5 and 6, the applicant submitted the required information. Following is an evaluation of the instrumentation provided.

1. Quench tank level--Regulatory Guide 1.97 recommends a range of top to bottom for this variable. The applicant has a horizontal tank with an inside diameter of 114 inches. The low level instrument tap is 7 inches from the bottom and the high level instrument tap is 7 inches from the top. The volume above and below the tap is 6 percent of the total tank volume. We find

this deviation minor and, therefore, acceptable. The existing range is capable of reading any expected accident or post-accident levels.

2. Quench tank temperature--Regulatory Guide 1.97 recommends a range of 50 to 750°F for this variable. The applicant has provided a range of 50 to 350°F. The applicant states that this range will monitor any expected conditions in the tank. In addition, the tank is equipped with a rupture disk with a release pressure of 91 psig. This corresponds to a saturation temperature of 320°F.

   The range covers the anticipated requirements for normal operation, anticipated operational occurrences and accident conditions. This range relates to the tank's rupture disk that relieves pressure in excess of 91 psig. This pressure relief limits the temperature of the tank contents to saturated steam conditions under 350°F. Thus, we find this deviation from the regulatory guide acceptable.

3. Quench tank pressure--Regulatory Guide 1.97 recommends a pressure range of 0 to design pressure for this variable. The applicant stated, in Reference 5, that the range is 0 to 100 psig, but did not provide the tank design pressure.

   In Reference 6, the applicant states that the design pressure of the tank is 100 psig, therefore, the instrumentation is acceptable.

3.3.18 Containment Atmosphere Temperature

Regulatory Guide 1.97 recommends Category 2 instrumentation with a range of 40 to 400°F for this variable. The applicant has supplied Category 3 instrumentation with a range of 0 to 200°F. The applicant states, in References 5 and 6, that the containment atmosphere temperature is not a key variable for accident monitoring; that the key variables for monitoring containment cooling are containment spray flow (Category 2), containment water level (Category 1), containment spray system valve status (Category 2), containment pressure (Category 1), containment spray pump status (Category 2), and the reactor containment building fan cooler differential pressure/status (Category 2). The applicant further states that immediately after containment spray is initiated, the containment atmosphere is saturated steam and that the temperature can be determined based on containment pressure.

We find that the applicant's application of Category 3 backup instrumentation is in accordance with the regulatory guide. Since containment pressure is an alternate measure of monitoring containment temperature the existing temperature range is adequate for this variable.

3.3.19 Containment Sump Water Temperature

Regulatory Guide 1.97 recommends Category 2 instrumentation for this variable. The applicant has not provided instrumentation for this variable. The residual heat removal (RHR) heat exchanger inlet temperature (essentially the same temperature as the sump) instruments are Category 2. The applicant states that further qualification of these instruments will not increase the safety of the station or increase the ability to mitigate the consequences of an accident or to bring the unit to a safe shutdown.

The applicant points out the following justifications in References 5 and 6.

1. There are no operator actions that are dependent on sump temperature.

2. Sump water is only used during the recirculation phase of an accident (i.e., pump suction has been switched over to the containment sump).

3. The RHR system is the only system that can reduce the sump water temperature. Monitoring of this cooling function is provided by RHR heat exchanger discharge temperature, component cooling water (CCW) pump and valve status, CCW header temperature and low head safety injection pump and valve status. These parameters are all monitored with Category 2 instrumentation.

4. The RHR pumps will have adequate net positive suction head regardless of the sump temperature.

5. Should a quantitative measure of heat removal be desired, the supplied instrumentation can be used.

The applicant does not have instrumentation or alternate instrumentation for this variable that is fully qualified to the Category 2 requirements. Thus, in a post-accident situation, a quantitative measure of the heat removal by way of the containment sump would not necessarily be available. Because of this, the applicant's justification is not acceptable.

The applicant should therefore provide instrumentation for this variable that is environmentally qualified in accordance with the provisions of 10 CFR 50.49 and Regulatory Guide 1.97.

3.3.20 High-Level Radioactive Liquid Tank Level

Radioactive Gas Holdup Tank Pressure

In Reference 4, the applicant did not provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737 for these variables. In References 5 and 6, the applicant submitted additional information. Following is an evaluation of the instrumentation provided.

a. High level radioactive liquid tank level--in Reference 6, the applicant states that transfer of fluids to the liquid waste tanks is not required immediately after an accident. The applicant further states that the level indication necessary during long-term recovery from an accident can be monitored in the radwaste control room and that this instrumentation is adequate and accessible. We find this acceptable.

b. Radioactive gas holdup tank pressure--Regulatory Guide 1.97 recommends instrumentation for this variable. The South Texas Project does not have radioactive gas holdup tanks, using a charcoal delay system instead. Thus, instrumentation for this variable is not needed.

3.3.21 Emergency Ventilation Damper Position

Regulatory Guide 1.97 recommends Category 2 instrumentation that provides open-closed status of the emergency ventilation dampers. In Reference 4, the applicant stated that they do not provide this instrumentation.

In Reference 5, the applicant states that ventilation dampers which are required to perform a safety function are provided with position indication instrumentation which meets the requirements of Regulatory Guide 1.97.

3.3.22 Vent from Steam Generator Safety Relief Valves or Atmospheric Dump Valves

In Reference 4, the applicant did not provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737 for this variable.

In Reference 5, the applicant identified the externally-mounted main steam line radiation monitors as the instrumentation used for this application.

The instrumentation provided meets the category and range recommendation and is adequate to provide the necessary accident and post-accident information. Therefore, we find this instrumentation acceptable in meeting the recommendations of Regulatory Guide 1.97.

3.3.23 Radiation Exposure Meters

The applicant has not provided the information required by Section 6.2 of Supplement No. 1 of NUREG-0737 for this variable.

Revision 3 of Regulatory Guide 1.97 deletes this variable. Therefore, we find it acceptable that the applicant does not have this instrumentation.

3.3.24 Plant and Environs Radiation (Portable Instrumentation)

Regulatory Guide 1.97 recommends instrumentation for this variable with a range of 10^{-3} to 10^{4} R/hr, photons and 10^{-3} to 10^{4} rads/hr, beta radiation and low energy photons. The applicant indicated, in Reference 4, that the range for this instrumentation is not applicable. In Reference 5, the applicant provided the required information. However, the supplied range is 10^{-3} to 5×10^{-3} R/hr, photons and 10^{-2} to 5×10^{4} rads/hr, beta. In Reference 6, the applicant stated that the ranges specified by the regulatory guide with the exception of the high range beta/gamma instrument, are covered by several pieces of survey equipment with overlapping ranges. Since an individual would not be sent into an area with radiation levels in excess of the provided range, the existing range is satisfactory.

We find the ranges provided by the applicant's monitoring instrumentation sufficient to determine the beta and gamma dose rates in areas accessible to personnel during accident conditions.

3.3.25 Plant and Environs Radioactivity (Portable Instrumentation)

In Reference 4, the applicant did not provide the information required by Section 6.2 of Supplement No. 1 of NUREG-0737.

In Reference 5, the applicant provided the required information stating that a portable Canberra multichannel analyzer is used. We find this acceptable.

3.3.26 Wind Direction

Wind Speed

Estimation of Atmospheric Stability

The applicant states that the instrumentation for these variables meets the requirements of Regulatory Guide 1.23. However, Regulatory Guide 1.97 recommends a vertical temperature difference range of -9°F to 18°F. The applicant has provided a range of -6°F to 6°F. In Reference 6, the applicant states that conformance to Regulatory Guide 1.23 is met by using sigma-theta (the standard deviation of the horizontal wind direction over a period of 15 minutes to 1 hour) as an alternate measure of atmospheric stability.

We find the deviation in vertical temperature difference range acceptable since Regulatory Guide 1.23 allows the use of sigma-theta as an alternate measure of atmospheric stability.

4. CONCLUSIONS

Based on our review, we find that the applicant either conforms to or is justified in deviating from Regulatory Guide 1.97, with the following exception:

1. Containment sump water temperature--the applicant should provide the recommended instrumentation for this variable or identify other environmentally qualified instrumentation that provides the same information (Section 3.3.19).

5. REFERENCES

1. NRC letter, D. G. Eisenhut to All Licensees of Operating Reactors, Applicants for Operating Licenses, and Holders of Construction Permits, "Supplement No. 1 to NUREG-0737--Requirements for Emergency Response Capability (Generic Letter No. 82-33)," December 17, 1982.

2. "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Regulatory Guide 1.97, Revision 2, NRC, Office of Standard Development, December 1980.

3. "Clarification of TMI Action Plan Requirements, Requirements for Emergency Response Capability," NUREG-0737, Supplement No. 1, NRC, Office of Nuclear Reactor Regulation, January 1983.

4. Houston Lighting and Power Company letter, J. H. Goldberg to H. Denton, NRC, "Final Safety Analysis Report Amendment 40" September 25, 1984, ST-HL-AE-1125.

5. Houston Lighting and Power Company letter, M. R. Wisenburg to V. S. Noonan, NRC, "Additional Information Regarding RG 1.97," March 26, 1986, ST-HL-AE-1630, File No.: G9.17.

6. Houston Lighting and Power Company letter, M. R. Wisenburg to V. S. Noonan, NRC, "Additional Information Regarding RG 1.97," May 23, 1986 ST-HL-AE-1664, File No.: G9.17.

7. "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Regulatory Guide 1.97, Revision 3, NRC, Office of Nuclear Regulatory Research, May 1983.

APPENDIX S

FOURTH AUDIT REPORT
HOUSTON LIGHTING AND POWER COMPANY
QUALIFIED DISPLAY PROCESSING SYSTEM

APPENDIX S

FOURTH AUDIT REPORT
HOUSTON LIGHTING AND POWER COMPANY
QUALIFIED DISPLAY PROCESSING SYSTEM

I. BACKGROUND

The Houston Lighting and Power Company (HL&P) is developing a microcomputer based system, which will perform functions that will directly impact upon the safe operation of its South Texas Project (STP). The STP is a dual 1250 MW Westinghouse Pressurized Water Reactor (PWR) Nuclear Generating Station, which is currently scheduled for completion and licensing by June 1987.

The microcomputer based system is being designed by Westinghouse and is called the Qualified Display Processing System (QDPS). This system is described in the applicant's FSAR and it is being designed to perform the following functions:

Data acquisition, processing, and qualified (Class 1E) display for Post Accident Monitoring,

Data acquisition, display, and analog control for Safe Shutdown and to address separation/isolation concerns for a postulated Control Room/Relay Room fire,

Data acquisition and digital processing of steam generator water level signals and primary coolant system hot leg temperature signals and transmission of these processed signals for use by the Reactor Trip System.

The staff's review of the QDPS began with three separate audits of the Verification and Validation Plan. These audits were conducted during August 26-29, 1985; March 24-27, 1986; and July 15-16, 1986. The staff's audit results and recommendations of these three audits are presented in Reference 1, Reference 2, and Reference 3 respectively.

In preparation for the fourth staff audit on the QDPS, the applicant requested a meeting with the staff, which was held on November 13, 1986, at NRC Headquarters in Bethesda, Maryland. During the meeting, the applicant identified and discussed the validation plan and an audit outline for the fourth audit. Based on the large bulk of design information available, the staff decided to review threads of information (discussed later). Three threads were selected for review. For one of these cases, errors had been discovered during the validation process. However, the staff stated that additional threads should be available for staff review in that other threads, time permitting, will be reviewed during the fourth audit.

The staff's fourth audit of the QDPS was conducted during November 18-19, 1986, at Westinghouse Electric Corporation's Nuclear Facilities, located in Monroeville, Pennsylvania. The audit was conducted by Mr. J. L. Mauck and Mr. S. Weiss of the NRC staff and Ms. J. Frawley of SoHar (NRC consultant).

II. SCOPE OF AUDIT

The purpose of this audit was to review the QDPS validation plan and its implementation. As discussed in the third audit, the validation plan must be sufficiently broad in scope to address any discrepancies in the design process and account for the lack of independent, formal design verification. This means that the validation plan should include a technique which demonstrates completeness between Functional Requirements and Software Design Specifications that were turned over to the validation team.

Figure 1 depicts the QDPS design verification and validation process. This figure shows the flow of information from initiation of the functional requirements through system hardware/software design, testing, verification, validation, and initiation/resolution of trouble reports.

To perform a review of the validation concept, the staff utilized a thread concept review during the audit. For this type of review the sensor signal is selected and followed from sensor through hardware and software components up to the interface with another system/componet. The concept of thread path audits is to follow a functional requirement through validation testing and the retesting required when a failure is encountered. The staff utilized this concept to verify that the forms and procedures were adequate and demonstrated proper levels of sign-offs and management control. The threads previously selected by the staff for review were followed as well as several selected by the audit group during the audit. The threads to be audited were selected by the following criteria:

1. Common Thread
   - SGWLCS
     System Channel Accuracy
     Quality Coding of Compensated Level
     Redundant Sensor Algorithm

2. Trouble Report Resolution
   - Steam Generator PORV
     Valve Position Feedback Calibration

3. Additional Algorithm
   - RWST Level (Category 1 Variable)
     Redundant Sensor Algorithm

During the audit process, the staff selected the following three additional threads:

1. Validation Trouble Report on Acronyms, (TR #6) (words spelled out when should have been abbreviated).

2. Validation Trouble Report on Datalink, (TR #12) (values were truncated incorrectly).

3. Validation Trouble Report on EPROM, (TR #8) (EPROM was incorrect)

In addition, another issue, clarification of physical media and verification of program listing, remained from the previous audits and was addressed during the fourth audit. To resolve this issue, the staff re-evaluated the PROM burn procedure including verification of the PROM burn, the labeling of the PROMs and PROM re-verification. In addition, worst-case scenarios for installing error and malicious mischief were evaluated.

III. THIRD AUDIT OPEN ISSUES

Issue 1 - No Evidence of the Use of a Requirements Matrix to Structure The Decomposition of the Functional Requirements

- Decomposition From Functional Requirements to Software Design Specification May Be Incomplete

Examination of the documents from the second audit indicated that the functional requirements from HL&P were not well documented and were the result of dynamic evolution. Prior to the second audit there was an accumulation of the documentation for the functional requirements in the appropriate form with the appropriate levels of signatures, the documentation of the software design documents and a functional requirements matrix prepared by the design group showing an audit trail from the functional requirements to the corresponding software unit. However, the completeness of this matrix could not be demonstrated to the satisfaction of the second audit team. The abbreviated format of the matrix was judged to indicate incompleteness by restricting the entries to software functional requirements and not by including those which were addressed by hardware or by other subsystems.

Prior to the third audit a second functional requirements matrix was prepared by two engineers who were independent of the design team. For each subsystem every requirement was listed by document number and paragraph number with a full description of the requirement, a statement of where the requirement was met, and the functional test required for validation. The third audit team reviewed this matrix and its associated documentation and found it acceptable. However, the final acceptance of the completed validation phase was performed at the fourth audit.

The present status of the verification and validation testing was evaluated by the staff. The verification and validation testing of the base-scope is complete as well as the verification and validation testing of the Control/SGWLCS upgrades. The verification and validation of the upgrades for the Plant Safety Monitoring System (PSMS) and the validation of the PSMS base scope are still in process.

The base scope validation status as of November 16, 1986, was established using a total number of test items for the QDPS system of 2,243. The total validation trouble reports issued was 16. The total special-test trouble reports issued was 13. These trouble reports illustrated that there were very few real design or hard code errors. The number of Trouble Reports issued to date during the validation process was significantly smaller due to the fact that the items were corrected as part of the verification process. The Trouble Report error types identified during the validation testing are still being identified and analyzed.

It should be noted that supplemental "Special Tests" were performed as part of the validation process. This additional testing covered the unique requirements of The Man-Machine Interface and Prudency which are not part of the QDPS functional requirements. A review of the Trouble Reports issued to date (during the validation process) indicated that discrepancies discovered could not have been found or identified during the verification process since the whole system needed to be on test (as was only done during the validation testing) for the problem to have been seen.

The methods utilized for resolution of the validation trouble reports are (1) software modifications, (2) hardware modifications, (3) revise test procedures, or (4) revise functional requirements. After a review of the validation program test results coupled with the statistical summary of the verification trouble reports by type, the following conclusions can be reached:

- The first audit report concluded that the deficiencies noted in the verification process at the design level would shift the risk of discovering discrepancies to the validation phase. In response to comments generated at the earlier audits, it was obvious that a greatly increased effort was devoted to the software verification process and problems were (and will be) resolved in the verification phase. The number of trouble reports generated through verification was more than 10 times the number generated in validation.

- The fact that 60% of the verification trouble reports were caused by insufficient documentation and inconsistent documentation serves to further emphasize the importance of independent verification of the design. (SoHar)

- An analysis of the 42 verification error codes supports the conclusion that structual as well as functional verification has been done as stated in the Design Verification and Validation Plan. This is important because recent studies have shown that functional testing alone is not adequate. (SoHar)

One problem which became apparent during the fourth review was the lack of one-to-one correspondence between the test shown in the functional requirements documentation and those actually performed. The applicant stated that part of the validation process was to evaluate the factory acceptance tests (FAT) to determine if further validation tests were required. The intent by the individuals decomposing the functional requirement was not to impose a stringent test requirement for the members of the validation team responsible for writing the test procedures. Instead, the intent was to define a test which would completely test the specified functional requirements. If the validators could identify an alternate FAT section or derive an alternate test such that the intent and/or objective of the functional decomposition was satisfied, that alternative is considered acceptable by the individuals decomposing the functional requirement. Hence, the validation engineer that initials and dates the validation sign-off sheet is responsible for determining that the specified validation test procedure meets the intent and/or objective of the functional requirement and suggested test description.

This issue will be resolved by a letter from the applicant stating that in all cases the validation tests performed were at least as rigorous as those listed in the functional requirements document. The staff considers this issue resolved for the fourth audit but will confirm this resolution in the QDPS safety evaluation report.

On the basis of this review the implementation of the validation plan was judged to be adequate.

Issue 2 - Clarification of Physical Media and Verification of Program Listing

One of the open items that remained from the third audit was the verification of the physical media that represents the program. The applicant and Westinghouse had requested clarification/interpretation of this item. The verification of physical media means those activities performed to ensure that the burned in programmable read only memory (PROM) contains the authorized program (i.e., security and safeguard measures).

The V&V Team has control of the V&V Configuration Management System (CFMS) which contains the authorized programs. The programs are not directly accessible by the Design Teams. The V&V Team controls the physical media (i.e., PROMS) which contain the programs utilized during the Validation process and perform the following to insure its integrity:

- Down-loading of the executable load module (i.e., HEX file) from the V&V CFMS on the VAX 8600 Computer System to the Intel PROM burner.

  NOTE: HEX file contains checksum which insures that the program transfer to the PROM burner is accurate.

- Burning of PROMS.

- Verification that PROMS were burned correctly.

- Marking of the PROMS.

- Reverification of PROMS against the HEX file after Validation testing is complete to insure that the PROMS still contain the proper HEX file programs.

We found the strict configuration management procedures acceptable. However, as stated in the third audit report (Reference 3), the steps of manually labelling each PROM with the subsystem, the cabinet, the slot and the unique version identifier did not entirely convince us that the correct version and the correct PROM would always be installed and not be subject to malicious mischief. The design does not take advantage of some of the capabilities of digital systems. Programmable systems are not only capable of executing diagnostics but also of reporting version identifiers, installation dates and other information if so designed.

A procedure has since been implemented by the applicant and Westinghouse which produces computer generated labels, one for the top and one for the bottom of each PROM. This label generation occurs at the same time that the code is generated that is burned onto the PROM.

In addition, the applicant has performed a series of test to determine the consequences of incorrectly installing a PROM either inadvertently or through malicious procedures. These test demonstrated that the machine would halt because of the checksum differences. The few instances where the machine didn't halt and execution continued, it was shown by bit comparisons that the PROMS were, in fact, identical. This is expected to occur occasionally in such a highly redundant system. The following is a summary of the results of the tests performed.

	Prom Switch Made	Result
1.	Switch within Control (on same board)	Halt (Stop)
2.	Switch a PROM Set between Control and SGWLCS, then intialize NVRAM and finally switch back the PROM Set	Aborted by Check Sum Diagnostics
3.	Switch A PROM from Control A to Control B	System ran
4.	Switch A PROM between Control A to SGWLCS A	Halt (Stop)

As a result of its review, the staff has concluded that the computer generated label is a vast improvement over manually labeling each PROM and that adequate procedures and safeguards exist within the QDPS to detect and indicate PROM installation error or malicious mischief. Therefore, this issue is resolved.

IV. SUMMARY AND CONCLUSION

Based on our audit of the design process and the verification and validation plan for the QDPS, the staff concludes that it is acceptable for the applicant to continue the design and manufacture of this system and to continue to execute the verification and validation program. The staff's review of the validation information provided during the third and fourth audit has restored confidence in the verification and validation of the QDPS and corrected the deficiencies noted in the first and second audits.

This review has shown that the validators' plan presented at the third audit has been appropriately implemented and executed. In addition, this review has shown that the applicant's method of clarification of physical media and verification of program listing is acceptable. Sufficient safeguards exist within the QDPS to detect and indicate PROM installation error or malicious mischief.

However, the acceptance is conditional on the resolution of the following confirmatory items:

(1) the staff is to review and provide a safety evaluation of the final QDPS V&V report (letter dated December 23, 1986, from M. R. Wisenburg to Vincent S. Noonan).

(2) After the validation Trouble Reports have been completed, a copy of the summary of all of the Trouble Reports, similar to the verification summary table with summary numbers, should be provided. The applicant and Westinghouse should review each Trouble Report and determine

whether these problems could have been previously found. The staff will review this data and report its findings in a safety evaluation to be issued at a later date.

(3) A letter needs to be provided by the applicant to the effect that the validation test procedures do not need to be followed to the letter, but that the referenced Factory Acceptance Test (FAT) procedures may be used provided that the validation testing does not accomplish the intended check, and the validation test procedure is more restrictive. The staff will confirm the receipt of this letter in a safety evaluation to be issued at a later date.

(4) The staff requested a commitment from HL&P to keep the NRC abreast of all troubles encountered and all changes made to the QDPS during the first operating cycle of the plant. This will provide the Staff a basis for evaluating the reliability of the system. The staff will confirm this commitment in a safety evaluation to be issued at a later date.

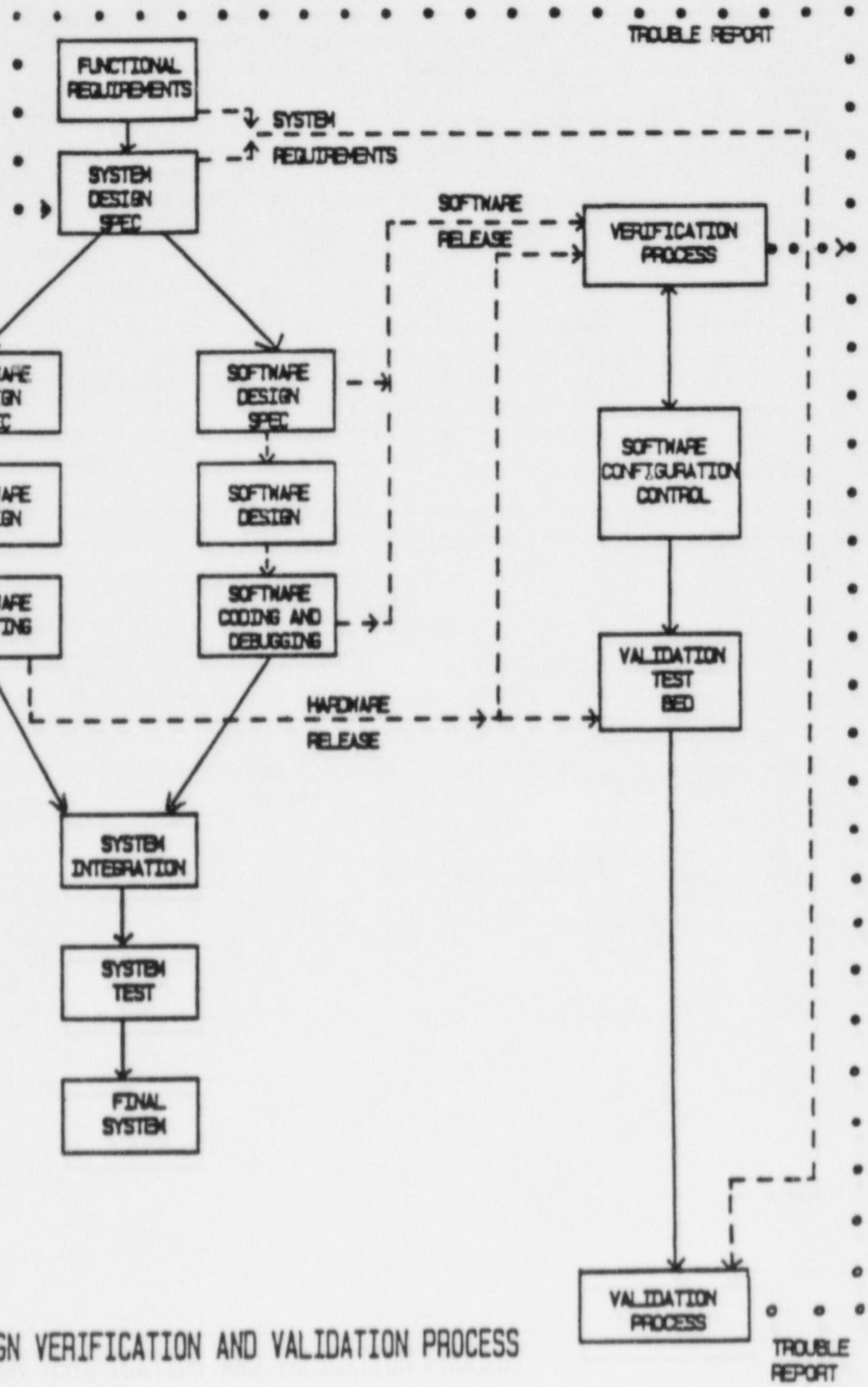
It should be noted that the instrumentation and control issues (discussed in Reference 3) will be reviewed as part of the Chapter 7 review.

REFERENCES

1. Letter from N. P. Kadambi, NRC to J.H. Goldberg, Houston Lighting and Power Company, Subject: Audit Report on the QDPS at South Texas Project, Units 1 and 2, dated January 30, 1986.

2. Letter from N. P. Kadambi, NRC to J. H. Goldberg, Houston Lighting and Power Company, Subject: Audit Report on the QDPS at South Texas Project, Units 1 and 2, dated May 19, 1986.

3. Letter from N. P. Kadambi, NRC to J. H. Goldberg, Houston Lighting and Power Company, Subject: Audit Report on the QDPS at South Texas Project, Units 1 and 2, dated October 7, 1986.



QDPS DESIGN VERIFICATION AND VALIDATION PROCESS

FIGURE 1

APPENDIX T

CONFORMANCE TO GENERIC LETTER 83-28
ITEM 2.1 (PART 2)

INPUT FOR
SAFETY EVALUATION REPORT
KEWAUNEE NUCLEAR POWER PLANT
McGUIRE NUCLEAR STATION UNITS 1 AND 2
PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNITS 1 AND 2
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
SALEM GENERATING STATION UNITS 1 AND 2
SHEARON HARRIS NUCLEAR POWER PLANT UNIT 1
SOUTH TEXAS PROJECT UNITS 1 AND 2
VIRGIL C. SUMMER NUCLEAR STATION
TROJAN NUCLEAR PLANT
REACTOR TRIP SYSTEM VENDOR INTERFACE
ITEM 2.1 (PART 2) OF GENERIC LETTER 83-28

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ABSTRACT

This EG&G Idaho, Inc. report provides a review of the submittals for some of the Westinghouse (W) nuclear plants for conformance to Generic Letter 83-28, Item 2.1 (Part 2). The report includes the following plants, all Westinghouse, and is in partial fulfillment of the following TAC Nos.:

Plant	Docket Number	TAC Number
Kewaunee Nuclear Power Plant	50-305	52848
McGuire Nuclear Station Unit 1	50-369	52852
McGuire Nuclear Station Unit 2	50-370	52853
Prairie Island Unit 1	50-282	52870
Prairie Island Unit 2	50-306	52871
Robinson 2	50-261	52875
Salem Unit 1	50-272	52876
Salem Unit 2	50-311	52877
Shearon Harris Unit 1 (OL)	50-400	N/A
South Texas Unit 1 (OL)	50-498	N/A
South Texas Unit 2 (OL)	50-499	N/A
Virgil C. Summer	50-395	52885
Trojan Nuclear Plant	50-344	52890

FOREWORD

This report is provided as part of the program for evaluating licensee/applicant conformance to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events." This work is conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A by EG&G Idaho, Inc.

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CONTENTS

CONFORMANCE TO GENERIC LETTER 83-28
ITEM 2.1 (PART 2)
KEWAUNEE NUCLEAR POWER PLANT
McGUIRE NUCLEAR STATION UNITS 1 AND 2
PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNITS 1 AND 2
H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
SALEM GENERATING STATION UNITS 1 AND 2
SHEARON HARRIS NUCLEAR POWER PLANT UNIT 1
SOUTH TEXAS PROJECT UNITS 1 AND 2
VIRGIL C. SUMMER NUCLEAR STATION
TROJAN NUCLEAR PLANT

1. INTRODUCTION

On July 8, 1983, Generic Letter 83-28[1] was issued by D. G. Eisenhut, Director of the Division of Licensing, Office of Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits. This letter included required actions based on generic implications of the Salem ATWS events. These requirements have been published in Volume 2 of NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant."[2]

This report documents the EG&G Idaho, Inc. review of the submittals of a group of Westinghouse plants including Kewaunee, McGuire Units 1 and 2, Prairie Island Units 1 and 2, Robinson 2, Salem Units 1 and 2, Shearon Harris Unit 1, South Texas Units 1 and 2, Summer and Trojan for conformance to Item 2.1 (Part 2) of Generic Letter 83-28. The submittals from the licensees and applicants utilized in these evaluations are referenced in Section 14 of this report.

2. REVIEW REQUIREMENTS

Item 2.1 (Part 2) (Reactor Trip System - Vendor Interface) requires licensees and applicants to establish, implement and maintain a continuing program to ensure that vendor information on Reactor Trip System (RTS) components is complete, current and controlled throughout the life of the plant, and appropriately referenced or incorporated in plant instructions and procedures. The vendor interface program is to include periodic communications with vendors to assure that all applicable information has been received, as well as a system of positive feedback with vendors for mailings containing technical information, e.g., licensee/applicant acknowledgement for receipt of technical information.

That part of the vendor interface program which ensures that vendor information on RTS components, once acquired, is appropriately controlled, referenced and incorporated in plant instructions and procedures, will be evaluated as part of the review of Item 2.2 of the Generic Letter.

Because the Nuclear Steam System Supplier (NSSS) is ordinarily also the supplier of the entire RTS, the NSSS is also the principal source of information on the components of the RTS. This review of the licensee and applicant submittals will:

1. Confirm that the licensee/applicant has identified an interface with either the NSSS or with the vendors of each of the components of the Reactor Trip System.

2. Confirm that the interface identified by licensees/applicants includes periodic communication with the NSSS or with the vendors of each of the components of the Reactor Trip System.

3. Confirm that the interface identified by licensees/applicants includes a system of positive feedback to confirm receipt of transmittals of technical information.

3. GROUP REVIEW RESULTS

The relevant submittals from each of the included reactor plants were reviewed to determine compliance with Item 2.1 (Part 2). First, the submittals from each plant were reviewed to establish that Item 2.1 (Part 2) was specifically addressed. Second, the submittals were evaluated to determine the extent to which each of the plants complies with the staff guidelines for Item 2.1 (Part 2).

4. REVIEW RESULTS FOR KEWAUNEE NUCLEAR POWER PLANT

4.1 Evaluation

Wisconsin Public Service Corporation, the licensee for Kewaunee, provided their response to Item 2.1 (Part 2) of the Generic Letter on November 15, 1984. In that response, the licensee confirms that the NSSS for Kewaunee is Westinghouse and that the RTS for Kewaunee is included as a part of the Westinghouse interface program established for the Kewaunee NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

4.2 Conclusion

The staff finds the licensee's confirming statement that Kewaunee is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

5. REVIEW RESULTS FOR McGUIRE NUCLEAR STATION UNITS 1 AND 2

5.1 Evaluation

Duke Power Company, the licensee for McGuire Units 1 and 2, provided their response to Item 2.1 (Part 2) of the Generic Letter on November 4, 1983. In that response, the licensee confirms that the NSSS for McGuire Units 1 and 2 is Westinghouse and that the RTS for McGuire Units 1 and 2 is included as a part of the Westinghouse interface program established for the McGuire Units 1 and 2 NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

5.2 Conclusion

The staff finds the licensee's confirming statement that McGuire Units 1 and 2 is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

6. REVIEW RESULTS FOR PRAIRIE ISLAND NUCLEAR GENERATING PLANT UNITS 1 AND 2

6.1 Evaluation

Northern confirms Power Company, the licensee for Prairie Island Units 1 and 2, responded to Item 2.1 (Part 2) of the Generic Letter on November 4, 1983. In that response, the licensee confirms that the NSSS for Prairie Island Units 1 and 2 is Westinghouse and that the RTS for Prairie Island Units 1 and 2 is included as a part of the Westinghouse interface program established for the Prairie Island Units 1 and 2 NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

6.2 Conclusion

The staff finds the licensee's confirming statement that Prairie Island Units 1 and 2 is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

7. REVIEW RESULTS FOR H. B. ROBINSON STEAM ELECTRIC PLANT UNIT NO. 2

7.1 Evaluation

Carolina Power and Light, the licensee for Robinson 2, responded to Item 2.1 (Part 2) of the Generic Letter on November 7, 1983. In that response the licensee confirms that the NSSS for Robinson 2 is Westinghouse and that the RTS for Robinson 2 is included as a part of the Westinghouse interface program established for the Robinson 2 NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

7.2 Conclusion

The staff finds the licensee's confirming statement that Robinson 2 is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

8. REVIEW RESULTS FOR SALEM GENERATING STATION UNITS 1 AND 2

8.1 Evaluation

Public Service Electric and Gas, the licensee for Salem Units 1 and 2, responded to the concern of Item 2.1 (Part 2) of the Generic Letter on March 8, 1983, and March 14, 1983. In those responses, the licensee confirms that the NSSS for Salem Units 1 and 2 is Westinghouse and that the RTS for Salem Units 1 and 2 is included as a part of the Westinghouse interface program established for the Salem Units 1 and 2 NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

8.2 Conclusion

The staff finds the licensee's confirming statement that Salem Units 1 and 2 is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

9. REVIEW RESULTS FOR SHEARON HARRIS NUCLEAR POWER PLANT UNIT 1

9.1 Evaluation

Carolina Power and Light, the applicant for Shearon Harris Unit 1, responded to Item 2.1 (Part 2) of the Generic Letter on November 7, 1983. In that response, the applicant confirms that the NSSS for Shearon Harris Unit 1 is Westinghouse and that the RTS for Shearon Harris Unit 1 is included as a part of the Westinghouse interface program established for the Shearon Harris Unit 1 NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

9.2 Conclusion

The staff finds the applicant's confirming statement that Shearon Harris Unit 1 is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

10. REVIEW RESULTS FOR SOUTH TEXAS PROJECT UNITS 1 AND 2

10.1 Evaluation

Houston Lighting and Power, the applicant for South Texas Units 1 and 2, provided their response to Item 2.1 (Part 2) of the Generic Letter on June 28, 1985. In that response, the applicant confirms that the NSSS for South Texas Units 1 and 2 is Westinghouse and that the RTS for South Texas Units 1 and 2 is included as a part of the Westinghouse interface program established for the South Texas Units 1 and 2 NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

10.2 Conclusion

The staff finds the applicant's confirming statement that South Texas Units 1 and 2 is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

11. REVIEW RESULTS FOR VIRGIL C. SUMMER NUCLEAR STATION

11.1 Evaluation

South Carolina Electric and Gas, the licensee for Virgil C. Summer, provided their response to Item 2.1 (Part 2) of the Generic Letter on November 4, 1983. In that response, the licensee confirms that the NSSS for Summer is Westinghouse and that the RTS for Summer is included as a part of the Westinghouse interface program established for the Summer NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

11.2 Conclusion

The staff finds the licensee's confirming statement that Summer is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

12. REVIEW RESULTS FOR TROJAN NUCLEAR PLANT

12.1 Evaluation

Portland General Electric Company, the licensee for Trojan Nuclear Plant, provided their response to Item 2.1 (Part 2) of the Generic Letter on November 4, 1983. In that response, the licensee confirms that the NSSS for Trojan is Westinghouse and that the RTS for Trojan is included as a part of the Westinghouse interface program established for the Trojan NSSS.

The Westinghouse interface program for the NSSS includes both periodic communication between Westinghouse and licensees/applicants and positive feedback from licensees/applicants in the form of signed receipts for technical information transmitted by Westinghouse.

12.2 Conclusion

The staff finds the licensee's confirming statement that Trojan is a participant in the Westinghouse interface program for the RTS meets the staff position on Item 2.1 (Part 2) of the Generic Letter and is, therefore, acceptable.

13. GROUP CONCLUSION

The staff concludes that the licensee/applicant responses for the listed Westinghouse plants for Item 4.5.2 of Generic Letter 83-28 are acceptable.

14. REFERENCES

1. NRC Letter, D. G. Eisenhut to all licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events (Generic Letter 83-28)," July 8, 1983.

2. Generic Implications of ATWS Events at the Salem Nuclear Power Plant NUREG-1000, Volume 1, April 1983; Volume 2, July 1983.

3. Wisconsin Public Service Corporation letter to NRC, D. C. Hintz to D. G. Eisenhut, Director, Division of Licensing, "Generic Implications of Salem ATWS Events," November 15, 1984.

4. Duke Power Company letter to NRC, W. T. Orders to D. G. Eisenhut, Director, Division of Licensing, November 4, 1983.

5. Northern States Power Company letter to NRC, D. M. Musolf, to Director, Office of Nuclear Reactor Regulation, "Generic Implications of Salem ATWS Events," November 4, 1983.

6. Carolina Power and Light letter to NRC, A. B. Cutter to D. G. Eisenhut, Director, Division of Licensing, "Generic Implications of Salem ATWS Events," November 7, 1983.

7. Public Service Electric and Gas letter to NRC, Richard A. Uderitz to D. G. Eisenhut, Director, Division of Licensing, "Reactor Trip Breaker Failure," March 8, 1983.

8. Public Service Electric and Gas letter to NRC, Richard A. Uderitz to D. G. Eisenhut, Director, Division of Licensing, "Corrective Action Program Related to Reactor Trip Breaker Failures," March 14, 1983.

9. Carolina Power and Light letter to NRC, A. B. Cutter to D. G. Eisenhut, Director, Division of Licensing, "Generic Implications of Salem ATWS Events," November 7, 1983.

10. Houston Lighting and Power letter to NRC, J. H. Goldberg to Hugh J. Thompson, Jr., Director, Division of Licensing, "Response to Generic Letter 83-28, Required Actions Based on Generic Implications of Salem ATWS Events," June 28, 1985.

11. South Carolina Electric and Gas letter to NRC, O. W. Dixon to Harold R. Denton, Director, Office of Nuclear Reactor Regulation, "Generic Letter 83-28," November 4, 1983.

12. Portland General Electric Company letter to NRC, Bart D. Withers, to Darrel G. Eisenhut, Director, Division of Licensing, "Generic Implications of Salem ATWS Events," November 4, 1983.

INPUT FOR
SAFETY EVALUATION REPORT
McGUIRE NUCLEAR STATION UNITS 1 AND 2
MILLSTONE NUCLEAR POWER STATION UNIT 3
SEABROOK STATION UNITS 1 AND 2
SOUTH TEXAS PROJECT UNITS 1 AND 2
VIRGIL C. SUMMER NUCLEAR STATION
VOGTLE ELECTRIC GENERATING PLANT UNITS 1 AND 2
WOLF CREEK GENERATING STATION
REACTOR TRIP SYSTEM RELIABILITY
ITEM 4.5.2 OF GENERIC LETTER 83-28

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ABSTRACT

This EG&G Idaho, Inc. report provides a review of the submittals for some of the Westinghouse (W) nuclear plants for conformance to Generic Letter 83-28, Item 4.5.2. The report includes the following plants, all Westinghouse, and is in partial fulfillment of the following TAC Nos.:

Plant	Docket Number	TAC Number
McGuire Nuclear Station Unit 1	50-369	53997
McGuire Nuclear Station Unit 2	50-370	53998
Millstone Nuclear Power Station Unit 3 (OL)	50-423	60401
Seabrook Station Unit 1 (OL)	50-443	N/A
Seabrook Station Unit 2 (OL)	50-444	N/A
South Texas Project Unit 1 (OL)	50-498	63489
South Texas Project Unit 2 (OL)	50-499	N/A
Virgil C. Summer Nuclear Station	50-395	54030
Vogtle Electric Generating Plant Unit 1 (OL)	50-424	N/A
Vogtle Electric Generating Plant Unit 2 (OL)	50-425	N/A
Wolf Creek Generating Station (OL)	50-482	N/A

FOREWORD

This report is provided as part of the program for evaluating licensee/applicant conformance to Generic Letter 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events." This work is conducted for the U.S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation, Division of PWR Licensing-A by EG&G Idaho, Inc.

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CONTENTS

CONFORMANCE TO GENERIC LETTER 83-28

ITEM 4.5.2

McGUIRE NUCLEAR STATION UNITS 1 AND 2

MILLSTONE NUCLEAR POWER STATION UNIT 3

SEABROOK STATION UNITS 1 AND 2

SOUTH TEXAS PROJECT UNITS 1 AND 2

VIRGIL C. SUMMER NUCLEAR STATION

VOGTLE ELECTRIC GENERATING PLANT UNITS 1 AND 2

WOLF CREEK GENERATING STATION

1. INTRODUCTION

On July 8, 1983, Generic Letter 83-28[1] was issued by D. G. Eisenhut, Director of the Division of Licensing, Office of Nuclear Reactor Regulation, to all licensees of operating reactors, applicants for operating licenses, and holders of construction permits. This letter included required actions based on generic implications of the Salem ATWS events. These requirements have been published in Volume 2 of NUREG-1000, "Generic Implications of ATWS Events at the Salem Nuclear Power Plant."[2]

This report documents the EG&G Idaho, Inc. review of the submittals of some of the Westinghouse plants including McGuire 1 and 2, Millstone 3, Seabrook 1 and 2, South Texas 1 and 2, Summer, Vogtle 1 and 2 and Wolf Creek for conformance to Item 4.5.2 of Generic Letter 83-28. The submittals from the licensees utilized in these evaluations are referenced in Section 12 of this report.

2. REVIEW REQUIREMENTS

Item 4.5.2 (Reactor Trip System Reliability - System Functional Testing - On-Line Testing) requires licensees and applicants with plants not currently designed to permit on-line testing to justify not making modifications to permit such testing. Alternatives to on-line testing will be considered where special circumstances exist and where the objective of high reliability can be met in another way. Item 4.5.2 may be interdependent with Item 4.5.3 when there is a need to justify not performing on-line testing because of the peculiarities of a particular design.

All portions of the Reactor Trip System that do not have on-line testing capability will be reviewed under the guidelines for this item. However, the existence of on-line testability for the Reactor Trip Breaker undervoltage and shunt trip attachments on Westinghouse, B&W and CE plants; the silicon controlled rectifiers in the CRDCS on B&W plants; and the scram pilot and backup scram valves on GE plants will only be confirmed here since they are specifically addressed in Items 4.4 and 4.5.1. Maintenance and testing of the Reactor Trip Breakers are also excluded from this review, as they are evaluated under Item 4.2. This review of the licensee/applicant submittals will:

1. Confirm that the licensee/applicant has identified those portions of the Reactor Trip System that are not on-line testable. If the entire Reactor Trip System is verified to be on-line testable, with those exceptions addressed above, no further review is required.

2. Evaluate modifications proposed by licensees/applicants to permit on-line testing against the existing criteria for the design of the protection systems for the plant being modified.

3. Evaluate proposed alternatives to on-line testing of the Reactor Trip System for acceptability based on the following:

a. The licensee/applicant submittal substantiates the impracticality of the modifications necessary to permit on-line testing, and

b. High Reactor Trip System availability (comparable to that which would be possible with on-line testing) is achieved in another way. Any such proposed alternative must be described in detail sufficient to permit an independent evaluation of the basis and analysis provided in lieu of performing on-line testing. Methods that may be used to demonstrate that the objective of high reliability has been met may include the following:

   i. Demonstration by systematic analysis that testing at shutdown intervals provides essentially equivalent reliability to that obtained by on-line testing at shorter intervals.

   ii. Demonstration that reliability equivalent to that obtained by on-line testing is accomplished by additional redundant and diverse components or by other features.

   iii. Development of a maintenance program based on early replacement of critical components that compensates for the lack of on-line testing. Such a program would require analytical justification supported by test data.

   iv. Development of a test program that compensates for the lack of on-line testing, e. g., one which uses trend analysis and identification of safety margins for critical parameters of safety-related components. Such a program would require analytical justification supported by test data.

4. Verify the capability to perform independent on-line testing of the reactor trip system breaker undervoltage and shunt trip attachments on

CE plants. Information from licensees and applicants with CE plants will be reviewed to verify that they require independent on-line testing of the reactor trip breaker undervoltage and shunt trip attachments.

3. GROUP REVIEW RESULTS

The relevant submittals from each of the Westinghouse reactor plants were reviewed to determine compliance with Item 4.5.2. First, the submittals from each plant were reviewed to establish that Item 4.5.2 was specifically addressed. Second, the submittals were evaluated to determine the extent to which each of the Westinghouse plants complies with the staff guidelines for Item 4.5.2.

4. REVIEW RESULTS FOR McGUIRE NUCLEAR STATION UNITS 1 AND 2

4.1 Evaluation

Duke Power Company, the license for McGuire 1 and 2, provided their response to Item 4.5.2 of the Generic Letter on November 4, 1983. In that response, the licensee states that on-line functional testing of the reactor trip system is performed for both McGuire units.

4.2 Conclusion

The staff finds the licensee's response meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

5. REVIEW RESULTS FOR MILLSTONE NUCLEAR POWER STATION UNIT 3

5.1 Evaluation

Northeast Utilities, the applicant for Millstone 3, provided their response to Item 4.5.2 of the Generic Letter on November 8, 1983. In that response, the applicant states that on-line functional testing of the Reactor Trip System will be performed at Millstone 3 and that procedures will be developed to perform independent testing of the shunt and undervoltage trip features of the reactor trip breakers.

5.2 Conclusion

The staff finds the applicant's response meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

6. REVIEW RESULTS FOR SEABROOK STATION UNITS 1 AND 2

6.1 Evaluation

Public Service Company of New Hampshire, the applicant for Seabrook 1 and 2, responded to Item 4.5.2 of the Generic Letter on November 4, 1983. In that response, the applicant states that Item 4.5.2 is not applicable to Seabrook, and that the Station staff will incorporate independent testing of the shunt and undervoltage trip features of the reactor trip breakers.

6.2 Conclusion

The staff finds the applicant's statement that Item 4.5.2 is not applicable to be confirmation that Seabrook will perform on-line testing of the RTS, that this confirmation meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

7. REVIEW RESULTS FOR SOUTH TEXAS PROJECT UNITS 1 AND 2

7.1 Evaluation

Houston Lighting and Power, the applicant for South Texas 1 and 2, responded to Item 4.5.2 of the Generic Letter on June 28, 1985. In that response, the applicant states that on-line functional testing will confirm the independent operability of the shunt and undervoltage trip devices, and that the capability for on-line functional testing of the Reactor Trip System will be provided.

7.2 Conclusion

The staff finds the applicant's statement that South Texas will have the capability to perform on-line testing of the RTS meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

8. REVIEW RESULTS FOR VIRGIL C. SUMMER NUCLEAR STATION

8.1 Evaluation

South Carolina Electric and Gas, the licensee for Summer, responded to Item 4.5.2 of the Generic Letter on November 4, 1983. In that response, the licensee states that Summer has submitted a design change to NRC to permit independent testing of the diverse trip features, and that Item 4.5.2 of the Generic Letter is not applicable.

8.2 Conclusion

The staff finds the licensee's statement that Item 4.5.2 is not applicable to be confirmation that Summer performs on-line testing of the RTS, that this confirmation meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

9. REVIEW RESULTS FOR VOGTLE ELECTRIC GENERATING PLANT UNITS 1 AND 2

9.1 Evaluation

Georgia Power Company, the applicant for Vogtle 1 and 2, responded to Item 4.5.2 of the Generic Letter on November 8, 1983, and May 20, 1985. In those responses, the applicant states Plant Vogtle is designed to allow on-line testing of the Reactor Trip System, with the exception of the bypass breakers, and that independent verification of the operation of the undervoltage and shunt trip attachments is dependent on implementation of the reactor trip breaker shunt trip modification.

9.2 Conclusion

The staff finds the applicant's statement that Plant Vogtle is designed to have the capability to perform on-line testing of the RTS meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

10. REVIEW RESULTS FOR WOLF CREEK GENERATING STATION

10.1 Evaluation

Kansas Gas and Electric Company, the applicant for Wolf Creek, responded to Item 4.5.2 of the Generic Letter on November 15, 1983. In that response, the applicant states that procedures for the on-line functional testing of the Reactor Trip System, including independent verification of the diverse trip features, are scheduled to be in place by fuel load.

10.2 Conclusion

The staff finds the applicant's statement that Wolf Creek is capable of performing on-line testing of the RTS meets the staff position on Item 4.5.2 of the Generic Letter and is, therefore, acceptable.

11. GROUP CONCLUSION

The staff concludes that the licensee/applicant responses for the listed Westinghouse plants for Item 4.5.2 of Generic Letter 83-28 are acceptable.

12. REFERENCES

1. NRC Letter, D. G. Eisenhut to all licensees of Operating Reactors, Applicants for Operating License, and Holders of Construction Permits, "Required Actions Based on Generic Implications of Salem ATWS Events (Generic Letter 83-28)," July 8, 1983.

2. Generic Implications of ATWS Events at the Salem Nuclear Power Plant NUREG-1000, Volume 1, April 1983; Volume 2, July 1983.

3. Duke Power Company letter to NRC, W. T. Orders to D. G. Eisenhut, Director, Division of Licensing, November 4, 1983.

4. Northeast Utilities letter to NRC, W. G. Counsil to D. G. Eisenhut, Director, Division of Licensing, "Response to Generic Letter 83-28, Generic Implications of Salem ATWS Events," November 8, 1983.

5. Public Service Company of New Hampshire letter to NRC, John DeVincentis to United States Nuclear Regulatory Commission, Division of Licensing, "Response to Generic Letter 83-28," November 4, 1983.

6. Houston Lighting and Power letter to NRC, J. H. Goldberg to Hugh J. Thompson, Jr., Director, Division of Licensing, "Response to Generic Letter 83-28, Required Actions Based on Generic Implications of Salem ATWS Events," June 28, 1985.

7. South Carolina Electric and Gas letter to NRC, O. W. Dixon to Harold R. Denton, Director, Office of Nuclear Reactor Regulation, "Generic Letter 83-28," November 4, 1983.

8. Georgia Power Company letter to NRC, D. O. Foster to Director of Nuclear Reactor Regulation, "Generic Letter 83-28," November 8, 1983.

9. Georgia Power Company letter to NRC, J. A. Bailey to Director of Nuclear Reactor Regulation, "Generic Letter 83-28," May 20, 1985.

10. Kansas Gas and Electric Company letter to NRC, Glenn L. Koster to Harold R. Denton, Director, Office of Nuclear Reactor Regulation, "Response to Generic Letter 83-28," November 15, 1983.

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14. ABSTRACT (200 words or less)

The Safety Evaluation Report issued in April 1986 provided the results of the NRC staff's review of the Houston Lighting and Power Company's application for licenses to operate the South Texas Project. The facility consists of two pressurized water nuclear Reactors located in Matagorda County, Texas.

Supplement No. 1, issued in September 1986 updated the information contained in the Safety Evaluation Report and addressed the ACRS Report issued on June 10, 1986.

Supplement No. 2 addresses and resolves some of the outstanding issues remaining after issuance of the Safety Evaluation Report and Supplement No. 1.

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