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SUPPLEMENT 19 TO NUREG-0933
"A PRIORITIZATION OF GENERIC SAFETY ISSUES"
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TABLE II

LISTING OF ALL TMI ACTION PLAN ITEMS, TASK ACTION PLAN ITEMS, NEW GENERIC ISSUES, AND HUMAN FACTORS ISSUES

This table contains the priority designations for all issues listed in this report. For those issues found to be covered in other issues described in this document, the appropriate notations have been made in the Safety Priority Ranking column, e.g., I.A.2.2 in the Safety Priority Ranking column means that Item I.A.2.6(3) is covered in Item I.A.2.2. For those issues found to be covered in programs not described in this document, the notation (S) was made in the Safety Priority Ranking column. For resolved issues that have resulted in new requirements for operating plants, the appropriate multiplant licensing action number is listed. The licensing action numbering system bears no relationship to the numbering systems used for identifying the prioritized issues. An explanation of the classification and status of the issues is provided in the legend below.

Legend

NOTES:
1 - Possible Resolution Identified for Evaluation
2 - Resolution Available (Documented in NUREG, NRC Memorandum, SER, or equivalent)
3 - Resolution Resulted in either: (a) The Establishment of New Regulatory Requirements (By Rule, SRP Change, or equivalent)
or (b) No New Requirements
4 - Issue to be Prioritized in the Future
5 - Issue that is not a Generic Safety Issue but should be Assigned Resources for Completion

HIGH - High Safety Priority
MEDIUM - Medium Safety Priority
LOW - Low Safety Priority
DROP - Issue Dropped as a Generic Issue
EI - Environmental Issue
I - Resolved TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737
LI - Licensing Issue
MPA - Multiplant Action
NA - Not Applicable
RI - Regulatory Impact Issue
S - Issue Covered in an NRC Program Outside the Scope of This Document
USI - Unresolved Safety Issue

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
			TMI ACTION PLAN ITEMS				
I.A	OPERATING PERSONNEL						
I.A.1	Operating Personnel and Staffing						
I.A.1.1	Shift Technical Advisor	-	NRR/DHFS/LQB	I	2	12/31/86	F-01
I.A.1.2	Shift Supervisor Administrative Duties	-	NRR/DHFS/LQB	I	2	12/31/86	
I.A.1.3	Shift Manning	-	NRR/DHFS/LQB	I	2	12/31/86	F-02
I.A.1.4	Long-Term Upgrading	Colmar	RES/DFO/HFBR	NOTE 3(a)	2	12/31/86	
I.A.2	Training and Qualifications of Operating Personnel						
I.A.2.1	Immediate Upgrading of Operator and Senior Operator Training and Qualifications	-	-	-			
I.A.2.1(1)	Qualifications - Experience	-	NRR/DHFS/LQB	I	5	12/31/87	F-03
I.A.2.1(2)	Training	-	NRR/DHFS/LQB	I	5	12/31/87	F-03
I.A.2.1(3)	Facility Certification of Competence and Fitness of Applicants for Operator and Senior Operator Licenses	-	NRR/DHFS/LQB	I	5	12/31/87	F-03
I.A.2.2	Training and Qualifications of Operations Personnel	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.3	Administration of Training Programs	-	NRR/DHFS/LQB	I	5	12/31/87	
I.A.2.4	NRR Participation in Inspector Training	Colmar	NRR/DHFS/LQB	LI (NOTE 3)	5	12/31/87	NA
I.A.2.5	Plant Drills	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6	Long-Term Upgrading of Training and Qualifications	-	-	-			
I.A.2.6(1)	Revise Regulatory Guide 1.8	Colmar	NRR/DHFT/HFIB	NOTE 3(a)	5	12/31/87	NA
I.A.2.6(2)	Staff Review of NRR 80-117	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6(3)	Revise 10 CFR 55	Colmar	NRR/DHFS/LQB	I.A.2.2	5	12/31/87	NA
I.A.2.6(4)	Operator Workshops	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6(5)	Develop Inspection Procedures for Training Program	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.2.6(6)	Nuclear Power Fundamentals	Colmar	NRR/DHFS/LQB	DROP	5	12/31/87	NA
I.A.2.7	Accreditation of Training Institutions	Colmar	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/87	NA
I.A.3	Licensing and Requalification of Operating Personnel						
I.A.3.1	Revise Scope of Criteria for Licensing Examinations	Emrit	NRR/DHFS/LQB	I	5	12/31/86	
I.A.3.2	Operator Licensing Program Changes	Emrit	NRR/DHFS/OLB	NOTE 3(b)	5	12/31/86	NA
I.A.3.3	Requirements for Operator Fitness	Colmar	RES/DRAO/HFSB	NOTE 3(b)	5	12/31/86	NA
I.A.3.4	Licensing of Additional Operations Personnel	Thatcher	NRR/DHFS/LQB	NOTE 3(b)	5	12/31/86	NA
I.A.3.5	Establish Statement of Understanding with INPO and DOE	Thatcher	NRR/DHFS/HFEB	LI (NOTE 3)	5	12/31/86	NA
I.A.4	Simulator Use and Development						
I.A.4.1	Initial Simulator Improvement	-	-	-			
I.A.4.1(1)	Short-Term Study of Training Simulators	Thatcher	NRR/DHFS/OLB	NOTE 3(b)	5	06/30/88	NA
I.A.4.1(2)	Interim Changes in Training Simulators	Thatcher	NRR/DHFS/OLB	NOTE 3(a)	5	06/30/88	
I.A.4.2	Long-Term Training Simulator Upgrade	-	-	-			
I.A.4.2(1)	Research on Training Simulators	Colmar	NRR/DHFT/HFIB	NOTE 3(a)	5	06/30/88	
I.A.4.2(2)	Upgrade Training Simulator Standards	Colmar	RES/DFO/HFBR	NOTE 3(a)	5	06/30/88	
I.A.4.2(3)	Regulatory Guide on Training Simulators	Colmar	RES/DFO/HFBR	NOTE 3(a)	5	06/30/88	
I.A.4.2(4)	Review Simulators for Conformance to Criteria	Colmar	NRR/DLPQ/LOLB	NOTE 3(a)	5	06/30/88	

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
I.A.4.3	Feasibility Study of Procurement of NRC Training Simulator	Colmar	RES/DAE/RSRB	LI (NOTE 3)	5	06/30/88	NA
I.A.4.4	Feasibility Study of NRC Engineering Computer	Colmar	RES/DAE/RSRB	LI (NOTE 3)	5	06/30/88	NA
I.B.	SUPPORT PERSONNEL						
I.B.1	Management for Operations						
I.B.1.1	Organization and Management Long-Term Improvements	-	-	-			
I.B.1.1(1)	Prepare Draft Criteria	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(2)	Prepare Commission Paper	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(3)	Issue Requirements for the Upgrading of Management and Technical Resources	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(4)	Review Responses to Determine Acceptability	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(5)	Review Implementation of the Upgrading Activities	Colmar	OIE/DQASIP/ORPB	NOTE 3(b)	3	12/31/86	NA
I.B.1.1(6)	Prepare Revisions to Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	I.A.2.6(1), 75	3	12/31/86	NA
I.B.1.1(7)	Issue Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	I.A.2.6(1), 75	3	12/31/86	NA
I.B.1.2	Evaluation of Organization and Management Improvements of Near-Term Operating License Applicants	-	-	-			
I.B.1.2(1)	Prepare Draft Criteria	-	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/86	NA
I.B.1.2(2)	Review Near-Term Operating License Facilities	-	NRR/DHFS/LQB	NOTE 3(b)	3	12/31/86	NA
I.B.1.2(3)	Include Findings in the SER for Each Near-Term Operating License Facility	-	NRR/DL/ORAB	NOTE 3(b)	3	12/13/86	NA
I.B.1.3	Loss of Safety Function	-	-	-			
I.B.1.3(1)	Require Licensees to Place Plant in Safest Shutdown Cooling Following a Loss of Safety Function Due to Personnel Error	Sege	RES	LI (NOTE 3)	3	12/31/86	NA
I.B.1.3(2)	Use Existing Enforcement Options to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	3	12/31/86	NA
I.B.1.3(3)	Use Non-Fiscal Approaches to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	3	12/31/86	NA
I.B.2	Inspection of Operating Reactors						
I.B.2.1	Revise OIE Inspection Program	-	-	-			
I.B.2.1(1)	Verify the Adequacy of Management and Procedural Controls and Staff Discipline	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(2)	Verify that Systems Required to Be Operable Are Properly Aligned	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(3)	Follow-up on Completed Maintenance Work Orders to Assure Proper Testing and Return to Service	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(4)	Observe Surveillance Tests to Determine Whether Test Instruments Are Properly Calibrated	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(5)	Verify that Licensees Are Complying with Technical Specifications	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(6)	Observe Routine Maintenance	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA
I.B.2.1(7)	Inspect Terminal Boards, Panels, and Instrument Racks for Unauthorized Jumpers and Bypasses	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)		11/30/83	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
I.B.2.2	Resident Inspector at Operating Reactors	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)		11/30/83	NA
I.B.2.3	Regional Evaluations	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)		11/30/83	NA
I.B.2.4	Overview of Licensee Performance	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)		11/30/83	NA
I.C	OPERATING PROCEDURES						
I.C.1	Short-Term Accident Analysis and Procedures Revision	-	-	-			
I.C.1(1)	Small Break LOCAs	-	NRR	I	3	12/31/86	
I.C.1(2)	Inadequate Core Cooling	-	NRR	I	3	12/31/86	F-04
I.C.1(3)	Transients and Accidents	-	NRR	I	3	12/31/86	F-05
I.C.1(4)	Confirmatory Analyses of Selected Transients	Riggs	NRR/DSI/RSB	NOTE 3(b)	3	12/31/86	NA
I.C.2	Shift and Relief Turnover Procedures	-	NRR	I	3	12/31/86	
I.C.3	Shift Supervisor Responsibilities	-	NRR	I	3	12/31/86	
I.C.4	Control Room Access	-	NRR	I	3	12/31/86	
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	-	NRR/DL	I	3	12/31/86	F-06
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	-	NRR/DL	I	3	12/31/86	F-07
I.C.7	NSSS Vendor Review of Procedures	-	NRR/DHFS/PSRB	I	3	12/31/86	
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	-	NRR/DHFS/PSRB	I	3	12/31/86	
I.C.9	Long-Term Program Plan for Upgrading of Procedures	Riggs	NRR/DHFS/PSRB	NOTE 3(b)	3	12/31/86	NA
I.D	CONTROL ROOM DESIGN						
I.D.1	Control Room Design Reviews	-	NRR/DL	I	7	06/30/95	F-08
I.D.2	Plant Safety Parameter Display Console	-	NRR/DL	I	7	06/30/95	F-09
I.D.3	Safety System Status Monitoring	Thatcher	RES/DE/MEB	NOTE 3(b)	7	06/30/95	NA
I.D.4	Control Room Design Standard	Thatcher	RES/DRPS/RHFB	NOTE 3(b)	7	06/30/95	NA
I.D.5	Improved Control Room Instrumentation Research	-	-	-			
I.D.5(1)	Operator-Process Communication	Thatcher	RES/DFO/HFBR	NOTE 3(b)	7	06/30/95	NA
I.D.5(2)	Plant Status and Post-Accident Monitoring	Thatcher	RES/DFO/HFBR	NOTE 3(a)	7	06/30/95	
I.D.5(3)	On-Line Reactor Surveillance System	Thatcher	RES/DE/MEB	NOTE 3(b)	7	06/30/95	NA
I.D.5(4)	Process Monitoring Instrumentation	Thatcher	RES/DFO/ICBR	NOTE 3(b)	7	06/30/95	NA
I.D.5(5)	Disturbance Analysis Systems	Thatcher	RES/DRPS/RHFB	LI (NOTE 3)	7	06/30/95	NA
I.D.6	Technology Transfer Conference	Thatcher	RES/DFO/HFBR	LI (NOTE 3)	7	06/30/95	NA
I.E	ANALYSIS AND DISSEMINATION OF OPERATING EXPERIENCE						
I.E.1	Office for Analysis and Evaluation of Operational Data	Matthews	AEOD/PTB	LI (NOTE 3)	2	06/30/95	NA
I.E.2	Program Office Operational Data Evaluation	Matthews	NRR/DL/ORAB	LI (NOTE 3)	2	06/30/95	NA
I.E.3	Operational Safety Data Analysis	Matthews	RES/DRA/RRBR	LI (NOTE 3)	2	06/30/95	NA
I.E.4	Coordination of Licensee, Industry, and Regulatory Programs	Matthews	AEOD/PTB	LI (NOTE 3)	2	06/30/95	NA
I.E.5	Nuclear Plant Reliability Data System	Matthews	AEOD/PTB	LI (NOTE 3)	2	06/30/95	NA
I.E.6	Reporting Requirements	Matthews	AEOD/PTB	LI (NOTE 3)	2	06/30/95	NA
I.E.7	Foreign Sources	Matthews	IP	LI (NOTE 3)	2	06/30/95	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
I.E.8	Human Error Rate Analysis	Matthews	RES/DFO/HFBR	LI (NOTE 3)	2	06/30/95	NA
I.F	QUALITY ASSURANCE						
I.F.1	Expand QA List	Pittman	RES/DRA/ARGIB	NOTE 3(b)	2	06/30/89	NA
I.F.2	Develop More Detailed QA Criteria	-	-	-			
I.F.2(1)	Assure the Independence of the Organization Performing the Checking Function	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(4)	Establish Criteria for Determining QA Requirements for Specific Classes of Equipment	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(5)	Establish Qualification Requirements for QA and QC Personnel	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(6)	Increase the Size of Licensees' QA Staff	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(7)	Clarify that the QA Program Is a Condition of the Construction Permit and Operating License	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(8)	Compare NRC QA Requirements with Those of Other Agencies	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	2	06/30/89	NA
I.F.2(10)	Clarify Requirements for Maintenance of "As-Built" Documentation	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.F.2(11)	Define Role of QA in Design and Analysis Activities	Pittman	OIE/DQASIP/QUAB	LOW	2	06/30/89	NA
I.G	PREOPERATIONAL AND LOW-POWER TESTING						
I.G.1	Training Requirements	-	NRR/DHFS/PSRB	I	2	06/30/89	
I.G.2	Scope of Test Program	V'Molen	NRR/DHFS/PSRB	NOTE 3(a)	2	06/30/89	NA
II.A	SITING						
II.A.1	Siting Policy Reformulation	V'Molen	NRR/DE/SAB	NOTE 3(b)	1	12/31/84	NA
II.A.2	Site Evaluation of Existing Facilities	V'Molen	NRR/DE/SAB	V.A.1	1	12/31/84	NA
II.B	CONSIDERATION OF DEGRADED OR MELTED CORES IN						
II.B.1	Reactor Coolant System Vents	-	NRR/DL	I	3	12/31/91	F-10
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	-	NRR/DL	I	3	12/31/91	F-11
II.B.3	Post-Accident Sampling	-	NRR/DL	I	3	12/31/91	F-12
II.B.4	Training for Mitigating Core Damage	-	NRR/DL	I	3	12/31/91	F-13
II.B.5	Research on Phenomena Associated with Core Degradation and Fuel Melting	-	-	-			
II.B.5(1)	Behavior of Severely Damaged Fuel	V'Molen	RES/DSR/AEB	LI (NOTE 5)	3	12/31/91	NA
II.B.5(2)	Behavior of Core-Melt	V'Molen	RES/DSR/AEB	LI (NOTE 5)	3	12/31/91	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.B.5(3)	Effect of Hydrogen Burning and Explosions on Containment Structure	V'Molen	RES/DSR/AEB	LI (NOTE 5)	3	12/31/91	NA
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	Pittman	NRR/DST/RRAB	NOTE 3(a)	3	12/31/91	
II.B.7	Analysis of Hydrogen Control	Matthews	NRR/DSI/CSB	II.B.8	3	12/31/91	
II.B.8	Rulemaking Proceeding on Degraded Core Accidents	V'Molen	RES/DRAO/RAMR	NOTE 3(a)	3	12/31/91	
II.C	RELIABILITY ENGINEERING AND RISK ASSESSMENT						
II.C.1	Interim Reliability Evaluation Program	Pittman	RES/DRAO/RRB	NOTE 3(b)	2	12/31/88	NA
II.C.2	Continuation of Interim Reliability Evaluation Program	Pittman	NRR/DST/RRAB	NOTE 3(b)	2	12/31/88	NA
II.C.3	Systems Interaction	Pittman	NRR/DST/GIB	A-17	2	12/31/88	NA
II.C.4	Reliability Engineering	Pittman	RES/DRPS/RHFB	NOTE 3(b)	2	12/31/88	NA
II.D	REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES						
II.D.1	Testing Requirements	-	NRR/DL	I	1	06/30/89	F-14
II.D.2	Research on Relief and Safety Valve Test Requirements	Riggs	RES	LOW	1	06/30/89	NA
II.D.3	Relief and Safety Valve Position Indication	-	NRR	I	1	06/30/89	
II.E	SYSTEM DESIGN						
II.E.1	Auxiliary Feedwater System						
II.E.1.1	Auxiliary Feedwater System Evaluation	-	NRR/DL	I	1	12/31/86	F-15
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	-	NRR/DL	I	1	12/31/86	F-16, F-17
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	Riggs	RES/DRA/RRBR	NOTE 3(a)	1	12/31/86	
II.E.2	Emergency Core Cooling System						
II.E.2.1	Reliance on ECCS	Riggs	NRR/DSI/RSB	II.K.3(17)	1	12/31/85	NA
II.E.2.2	Research on Small Break LOCAs and Anomalous Transients	Riggs	RES/DAE/RSRB	NOTE 3(b)	1	12/31/85	NA
II.E.2.3	Uncertainties in Performance Predictions	V'Molen	NRR/DSI/RSB	LOW	1	12/31/85	NA
II.E.3	Decay Heat Removal						
II.E.3.1	Reliability of Power Supplies for Natural Circulation	-	NRR/DL	I	1	06/30/91	
II.E.3.2	Systems Reliability	V'Molen	NRR/DST/GIB	A-45	1	06/30/91	NA
II.E.3.3	Coordinated Study of Shutdown Heat Removal Requirements	V'Molen	NRR/DST/GIB	A-45	1	06/30/91	NA
II.E.3.4	Alternate Concepts Research	Riggs	RES/DAE/FBRB	NOTE 3(b)	1	06/30/91	NA
II.E.3.5	Regulatory Guide	Riggs	NRR/DST/GIB	A-45	1	06/30/91	NA
II.E.4	Containment Design						
II.E.4.1	Dedicated Penetrations	-	NRR/DL	I		06/30/88	F-18
II.E.4.2	Isolation Dependability	-	NRR/DL	I		06/30/88	F-19
II.E.4.3	Integrity Check	Milstead	RES/DRPS/RPSI	NOTE 3(b)		06/30/88	NA
II.E.4.4	Purging	-	-	-			
II.E.4.4(1)	Issue Letter to Licensees Requesting Limited Purging	Milstead	NRR/DSI/CSB	NOTE 3(a)		06/30/88	

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.E.4.4(2)	Issue Letter to Licensees Requesting Information on Isolation Letter	Milstead	NRR/DSI/CSB	NOTE 3(a)		06/30/88	
II.E.4.4(3)	Issue Letter to Licensees on Valve Operability	Milstead	NRR/DSI/CSB	NOTE 3(a)		06/30/88	
II.E.4.4(4)	Evaluate Purging and Venting During Normal Operation	Milstead	NRR/DSI/CSB	NOTE 3(b)		06/30/88	NA
II.E.4.4(5)	Issue Modified Purging and Venting Requirement	Milstead	NRR/DSI/CSB	NOTE 3(b)		06/30/88	NA
II.E.5	Design Sensitivity of B&W Reactors						
II.E.5.1	Design Evaluation	Thatcher	NRR/DSI/RSB	NOTE 3(a)	1	12/31/84	
II.E.5.2	B&W Reactor Transient Response Task Force	Thatcher	NRR/DL/ORAB	NOTE 3(a)	1	12/31/84	
II.E.6	In Situ Testing of Valves						
II.E.6.1	Test Adequacy Study	Thatcher	RES/DE/EIB	NOTE 3(a)	1	06/30/89	
II.F	INSTRUMENTATION AND CONTROLS						
II.F.1	Additional Accident Monitoring Instrumentation	-	NRR/DL	I	2	06/30/89	F-20, F-21, F-22, F-23, F-24, F-25
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	-	NRR/DL	I	2	06/30/89	F-26
II.F.3	Instruments for Monitoring Accident Conditions	V'Molen	RES/DFO/ICBR	NOTE 3(a)	2	06/30/89	
II.F.4	Study of Control and Protective Action Design Requirements	Thatcher	NRR/DSI/ICSB	DROP	2	06/30/89	NA
II.F.5	Classification of Instrumentation, Control, and Electrical Equipment	Thatcher	RES/DE	LI (NOTE 3)	2	06/30/89	NA
II.G	ELECTRICAL POWER						
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	-	NRR	I		12/31/94	NA
II.H	TMI-2 CLEANUP AND EXAMINATION						
II.H.1	Maintain Safety of TMI-2 and Minimize Environmental Impact	Matthews	NRR/TMIPO	NOTE 3(b)	2	06/30/95	NA
II.H.2	Obtain Technical Data on the Conditions Inside the TMI-2 Containment Structure	Milstead	RES/DRAA/AEB	NOTE 3(b)	2	06/30/95	NA
II.H.3	Evaluate and Feed Back Information Obtained from TMI	Milstead	NRR/TMIPO	II.H.2	2	06/30/95	NA
II.H.4	Determine Impact of TMI on Socioeconomic and Real Property Values	Milstead	RES/DHSWM/SEBR	LI (NOTE 3)	2	06/30/95	NA
II.J	GENERAL IMPLICATIONS OF TMI FOR DESIGN AND CONSTRUCTION ACTIVITIES						
II.J.1	Vendor Inspection Program						
II.J.1.1	Establish a Priority System for Conducting Vendor Inspections	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.1.2	Modify Existing Vendor Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.J.1.3	Increase Regulatory Control Over Present Non-Licensees	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.1.4	Assign Resident Inspectors to Reactor Vendors and Architect-Engineers	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.2	Construction Inspection Program						
II.J.2.1	Reorient Construction Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.2.2	Increase Emphasis on Independent Measurement in Construction Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.2.3	Assign Resident Inspectors to All Construction Sites	Riani	OIE/DQASIP	LI (NOTE 3)		11/30/83	NA
II.J.3	Management for Design and Construction						
II.J.3.1	Organization and Staffing to Oversee Design and Construction	Pittman	NRR/DHFS/LQB	I.B.1.1		11/30/83	NA
II.J.3.2	Issue Regulatory Guide	Pittman	NRR/DHFS/LQB	I.B.1.1		11/30/83	NA
II.J.4	Revise Deficiency Reporting Requirements						
II.J.4.1	Revise Deficiency Reporting Requirements	Riani	AEOD/DSP/ROAB	NOTE 3(a)	2	06/30/95	NA
II.K	MEASURES TO MITIGATE SMALL-BREAK LOSS-OF-COOLANT ACCIDENTS AND LOSS-OF-FEEDWATER ACCIDENTS						
II.K.1	IE Bulletins	-	-	-			
II.K.1(1)	Review TMI-2 PNs and Detailed Chronology of the TMI-2 Accident	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(2)	Review Transients Similar to TMI-2 That Have Occurred at Other Facilities and NRC Evaluation of Davis-Besse Event	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(3)	Review Operating Procedures for Recognizing, Preventing, and Mitigating Void Formation in Transients and Accidents	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(4)	Review Operating Procedures and Training Instructions	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(5)	Safety-Related Valve Position Description	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(6)	Review Containment Isolation Initiation Design and Procedures	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(7)	Implement Positive Position Controls on Valves That Could Compromise or Defeat AFW Flow	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(8)	Implement Procedures That Assure Two Independent 100% AFW Flow Paths	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(9)	Review Procedures to Assure That Radioactive Liquids and Gases Are Not Transferred out of Containment Inadvertently	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(10)	Review and Modify Procedures for Removing Safety-Related Systems from Service	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(11)	Make All Operating and Maintenance Personnel Aware of the Seriousness and Consequences of the Erroneous Actions Leading up to, and in Early Phases of, the TMI-2 Accident	Emrit	NRR	NOTE 3(a)		12/31/84	-

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.K.1(12)	One Hour Notification Requirement and Continuous Communications Channels	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(13)	Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(14)	Review Operating Modes and Procedures to Deal with Significant Amounts of Hydrogen	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(15)	For Facilities with Non-Automatic AFW Initiation, Provide Dedicated Operator in Continuous Communication with CR to Operate AFW	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(16)	Implement Procedures That Identify PRZ PORV "Open" Indications and That Direct Operator to Close Manually at "Reset" Setpoint	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(17)	Trip PZR Level Bistable so That PZR Low Pressure Will Initiate Safety Injection	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(18)	Develop Procedures and Train Operators on Methods of Establishing and Maintaining Natural Circulation	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(19)	Describe Design and Procedure Modifications to Reduce Likelihood of Automatic PZR PORV Actuation in Transients	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(20)	Provide Procedures and Training to Operators for Prompt Manual Reactor Trip for LOFW, TT, MSIV Closure, LOOP, LOSG Level, and LO PZR Level	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(21)	Provide Automatic Safety-Grade Anticipatory Reactor Trip for LOFW, TT, or Significant Decrease in SG Level	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When FW System Not Operable	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(23)	Describe Uses and Types of RV Level Indication for Automatic and Manual Initiation Safety Systems	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(24)	Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and RCP Trip	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(25)	Develop Operator Action Guidelines	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(26)	Revise Emergency Procedures and Train ROs and SROs	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(27)	Provide Analyses and Develop Guidelines and Procedures for Inadequate Core Cooling Conditions	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.1(28)	Provide Design That Will Assure Automatic RCP Trip for All Circumstances Where Required	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.2	Commission Orders on B&W Plants	-	-	-			
II.K.2(1)	Upgrade Timeliness and Reliability of AFW System	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(2)	Procedures and Training to Initiate and Control AFW Independent of Integrated Control System	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.2(3)	Hard-Wired Control-Grade Anticipatory Reactor Trips	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(4)	Small-Break LOCA Analysis, Procedures and Operator Training	Emrit	NRR/DHFS/OLB	NOTE 3(a)		12/31/84	-
II.K.2(5)	Complete TMI-2 Simulator Training for All Operators	Emrit	NRR	NOTE 3(a)		12/31/84	-
II.K.2(6)	Reevaluate Analysis for Dual-Level Setpoint Control	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.K.2(7)	Reevaluate Transient of September 24, 1977	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.2(8)	Continued Upgrading of AFW System	Emrit	NRR	II.E.1.1, II.E.1.2		12/31/84	NA
II.K.2(9)	Analysis and Upgrading of Integrated Control System	Emrit	NRR	I		12/31/84	F-27
II.K.2(10)	Hard-Wired Safety-Grade Anticipatory Reactor Trips	Emrit	NRR	I		12/31/84	F-28
II.K.2(11)	Operator Training and Drilling	Emrit	NRR	I		12/31/84	F-29
II.K.2(12)	Transient Analysis and Procedures for Management of Small Breaks	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.2(13)	Thermal-Mechanical Report on Effect of HPI on Vessel Integrity for Small-Break LOCA With No AFW	Emrit	NRR	I		12/31/84	F-30
II.K.2(14)	Demonstrate That Predicted Lift Frequency of PORVs and SVs Is Acceptable	Emrit	NRR	I		12/31/84	F-31
II.K.2(15)	Analysis of Effects of Slug Flow on Once-Through Steam Generator Tubes After Primary System Voiding	Emrit	NRR	I		12/31/84	-
II.K.2(16)	Impact of RCP Seal Damage Following Small-Break LOCA With Loss of Offsite Power	Emrit	NRR	I		12/31/84	F-32
II.K.2(17)	Analysis of Potential Voiding in RCS During Anticipated Transients	Emrit	NRR	I		12/31/84	F-33
II.K.2(18)	Analysis of Loss of Feedwater and Other Anticipated Transients	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.2(19)	Benchmark Analysis of Sequential AFW Flow to Once-Through Steam Generator	Emrit	NRR	I		12/31/84	F-34
II.K.2(20)	Analysis of Steam Response to Small-Break LOCA That Causes System Pressure to Exceed PORV Setpoint	Emrit	NRR	I		12/31/84	F-35
II.K.2(21)	LOFT L3-1 Predictions	Emrit	NRR/DSI	NOTE 3(a)		12/31/84	-
II.K.3	Final Recommendations of Bulletins and Orders Task Force	-	-	-			
II.K.3(1)	Install Automatic PORV Isolation System and Perform Operational Test	Emrit	NRR	I		12/31/84	F-36
II.K.3(2)	Report on Overall Safety Effect of PORV Isolation System	Emrit	NRR	I		12/31/84	F-37
II.K.3(3)	Report Safety and Relief Valve Failures Promptly and Challenges Annually	Emrit	NRR	I		12/31/84	F-38
II.K.3(4)	Review and Upgrade Reliability and Redundancy of Non-Safety Equipment for Small-Break LOCA Mitigation	Emrit	NRR	II.C.1, II.C.2, II.C.3		12/31/84	NA
II.K.3(5)	Automatic Trip of Reactor Coolant Pumps	Emrit	NRR	I		12/31/84	F-39, G-01
II.K.3(6)	Instrumentation to Verify Natural Circulation	Emrit	NRR/DSI	I.C.1(3), II.F.2, II.F.3		12/31/84	NA
II.K.3(7)	Evaluation of PORV Opening Probability During Overpressure Transient	Emrit	NRR	I		12/31/84	-
II.K.3(8)	Further Staff Consideration of Need for Diverse Decay Heat Removal Method Independent of SGs	Emrit	NRR/DST/GIB	II.C.1, II.E.3.3		12/31/84	NA
II.K.3(9)	Proportional Integral Derivative Controller Modification	Emrit	NRR	I		12/31/84	F-40

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.K.3(10)	Anticipatory Trip Modification Proposed by Some Licensees to Confine Range of Use to High Power Levels	Emrit	NRR	I		12/31/84	F-41
II.K.3(11)	Control Use of PORV Supplied by Control Components, Inc. Until Further Review Complete	Emrit	NRR	I		12/31/84	-
II.K.3(12)	Confirm Existence of Anticipatory Trip Upon Turbine Trip	Emrit	NRR	I		12/31/84	F-42
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	Emrit	NRR	I		12/31/84	F-43
II.K.3(14)	Isolation of Isolation Condensers on High Radiation	Emrit	NRR	I		12/31/84	F-44
II.K.3(15)	Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems	Emrit	NRR	I		12/31/84	F-45
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification	Emrit	NRR	I		12/31/84	F-46
II.K.3(17)	Report on Outage of ECC Systems - Licensee Report and Technical Specification Changes	Emrit	NRR	I		12/31/84	F-47
II.K.3(18)	Modification of ADS Logic - Feasibility Study and Modification for Increased Diversity for Some Event Sequences	Emrit	NRR	I		12/31/84	F-48
II.K.3(19)	Interlock on Recirculation Pump Loops	Emrit	NRR	I		12/31/84	F-49
II.K.3(20)	Loss of Service Water for Big Rock Point	Emrit	NRR	I		12/31/84	-
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level - Design and Modification	Emrit	NRR	I		12/31/84	F-50
II.K.3(22)	Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design	Emrit	NRR	I		12/31/84	F-51
II.K.3(23)	Central Water Level Recording	Emrit	NRR	I.D.2, III.A.1.2(1), III.A.3.4		12/31/84	NA
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	Emrit	NRR	I		12/31/84	F-52
II.K.3(25)	Effect of Loss of AC Power on Pump Seals	Emrit	NRR	I		12/31/84	F-53
II.K.3(26)	Study Effect on RHR Reliability of Its Use for Fuel Pool Cooling	Emrit	NRR/DSI	II.E.2.1		12/31/84	NA
II.K.3(27)	Provide Common Reference Level for Vessel Level Instrumentation	Emrit	NRR	I		12/31/84	F-54
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	Emrit	NRR	I		12/31/84	F-55
II.K.3(29)	Study to Demonstrate Performance of Isolation Condensers with Non-Condensibles	Emrit	NRR	I		12/31/84	F-56
II.K.3(30)	Revised Small-Break LOCA Methods to Show Compliance with 10 CFR 50, Appendix K	Emrit	NRR	I		12/31/84	F-57
II.K.3(31)	Plant-Specific Calculations to Show Compliance with 10 CFR 50.46	Emrit	NRR	I		12/31/84	F-58
II.K.3(32)	Provide Experimental Verification of Two-Phase Natural Circulation Models	Emrit	NRR/DSI	II.E.2.2		12/31/84	NA
II.K.3(33)	Evaluate Elimination of PORV Function	Emrit	NRR	II.C.1		12/31/84	NA
II.K.3(34)	Relap-4 Model Development	Emrit	NRR/DSI	II.E.2.2		12/31/84	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
II.K.3(35)	Evaluation of Effects of Core Flood Tank Injection on Small-Break LOCAs	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(36)	Additional Staff Audit Calculations of B&W Small-Break LOCA Analyses	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(37)	Analysis of B&W Response to Isolated Small-Break LOCA	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(38)	Analysis of Plant Response to a Small-Break LOCA in the Pressurizer Spray Line	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(39)	Evaluation of Effects of Water Slugs in Piping Caused by HPI and CFT Flows	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(40)	Evaluation of RCP Seal Damage and Leakage During a Small-Break LOCA	Emrit	NRR	II.K.2(16)		12/31/84	NA
II.K.3(41)	Submit Predictions for LOFT Test L3-6 with RCPs Running	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(42)	Submit Requested Information on the Effects of Non-Condensible Gases	Emrit	NRR	I.C.1(3)		12/31/84	NA
II.K.3(43)	Evaluation of Mechanical Effects of Slug Flow on Steam Generator Tubes	Emrit	NRR	II.K.2(15)		12/31/84	NA
II.K.3(44)	Evaluation of Anticipated Transients with Single Failure to Verify No Significant Fuel Failure	Emrit	NRR	I		12/31/84	F-59
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	Emrit	NRR	I		12/31/84	F-60
II.K.3(46)	Response to List of Concerns from ACRS Consultant	Emrit	NRR	I		12/31/84	F-61
II.K.3(47)	Test Program for Small-Break LOCA Model Verification Pretest Prediction, Test Program, and Model Verification	Emrit	NRR	I.C.1(3), II.E.2.2		12/31/84	NA
II.K.3(48)	Assess Change in Safety Reliability as a Result of Implementing B&OTF Recommendations	Emrit	NRR	II.C.1, II.C.2		12/31/84	NA
II.K.3(49)	Review of Procedures (NRC)	Emrit	NRR/DHFS/PSRB	I.C.8, I.C.9		12/31/84	NA
II.K.3(50)	Review of Procedures (NSSS Vendors)	Emrit	NRR/DHFS/PSRB	I.C.7, I.C.9		12/31/84	NA
II.K.3(51)	Symptom-Based Emergency Procedures	Emrit	NRR/DHFS/PSRB	I.C.9		12/31/84	NA
II.K.3(52)	Operator Awareness of Revised Emergency Procedures	Emrit	NRR	I.B.1.1, I.C.2, I.C.5		12/31/84	NA
II.K.3(53)	Two Operators in Control Room	Emrit	NRR	I.A.1.3		12/31/84	NA
II.K.3(54)	Simulator Upgrade for Small-Break LOCAs	Emrit	NRR	I.A.4.1(2)		12/31/84	NA
II.K.3(55)	Operator Monitoring of Control Board	Emrit	NRR	I.C.1(3), I.D.2, I.D.3		12/31/84	NA
II.K.3(56)	Simulator Training Requirements	Emrit	NRR/DHFS/OLB	I.A.2.6(3), I.A.3.1		12/31/84	NA
II.K.3(57)	Identify Water Sources Prior to Manual Activation of ADS	Emrit	NRR	I		12/31/84	F-62

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
III.A	EMERGENCY PREPAREDNESS AND RADIATION EFFECTS						
III.A.1	Improve Licensee Emergency Preparedness - Short-Term						
III.A.1.1	Upgrade Emergency Preparedness	-	-	-			
III.A.1.1(1)	Implement Action Plan Requirements for Promptly Improving Licensee Emergency Preparedness	-	OIE/DEPER/EPB	I	2	06/30/91	
III.A.1.1(2)	Perform an Integrated Assessment of the Implementation	-	OIE/DEPER/EPB	NOTE 3(b)	2	06/30/91	NA
III.A.1.2	Upgrade Licensee Emergency Support Facilities	-	-	-	2	06/30/91	
III.A.1.2(1)	Technical Support Center	-	OIE/DEPER/EPB	I	2	06/30/91	F-63
III.A.1.2(2)	On-Site Operational Support Center	-	OIE/DEPER/EPB	I	2	06/30/91	F-64
III.A.1.2(3)	Near-Site Emergency Operations Facility	-	OIE/DEPER/EPB	I	2	06/30/91	F-65
III.A.1.3	Maintain Supplies of Thyroid-Blocking Agent	-	-	-	2	06/30/91	
III.A.1.3(1)	Workers	Riggs	OIE/DEPER/EPB	NOTE 3(b)	2	06/30/91	NA
III.A.1.3(2)	Public	Riggs	OIE/DEPER/EPB	NOTE 3(b)	2	06/30/91	NA
III.A.2	Improving Licensee Emergency Preparedness - Long-Term						
III.A.2.1	Amend 10 CFR 50 and 10 CFR 50, Appendix E	-	-	-			
III.A.2.1(1)	Publish Proposed Amendments to the Rules	-	RES	NOTE 3(a)		12/31/94	NA
III.A.2.1(2)	Conduct Public Regional Meetings	-	RES	NOTE 3(b)		12/31/94	NA
III.A.2.1(3)	Prepare Final Commission Paper Recommending Adoption of Rules	-	RES	NOTE 3(b)		12/31/94	NA
III.A.2.1(4)	Revise Inspection Program to Cover Upgraded Requirements	-	OIE	I			F-67
III.A.2.2	Development of Guidance and Criteria	-	NRR/DL	I			F-68
III.A.3	Improving NRC Emergency Preparedness						
III.A.3.1	NRC Role in Responding to Nuclear Emergencies	-	-	-			
III.A.3.1(1)	Define NRC Role in Emergency Situations	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.1(2)	Revise and Upgrade Plans and Procedures for the NRC Emergency Operations Center	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.1(3)	Revise Manual Chapter 0502, Other Agency Procedures, and NUREG-0610	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.1(4)	Prepare Commission Paper	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.1(5)	Revise Implementing Procedures and Instructions for Regional Offices	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.2	Improve Operations Centers	Riggs	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.3	Communications	-	-	-			
III.A.3.3(1)	Install Direct Dedicated Telephone Lines	Pittman	OIE/DEPER/IRDB	NOTE 3(a)	1	06/30/85	NA
III.A.3.3(2)	Obtain Dedicated, Short-Range Radio Communication Systems	Pittman	OIE/DEPER/IRDB	NOTE 3(a)	1	06/30/85	NA
III.A.3.4	Nuclear Data Link	Thatcher	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	
III.A.3.5	Training, Drills, and Tests	Pittman	OIE/DEPER/IRDB	NOTE 3(b)	1	06/30/85	NA
III.A.3.6	Interaction of NRC and Other Agencies	-	-	-			
III.A.3.6(1)	International	Pittman	OIE/DEPER/EPLB	NOTE 3(b)	1	06/30/85	NA
III.A.3.6(2)	Federal	Pittman	OIE/DEPER/EPLB	NOTE 3(b)	1	06/30/85	NA
III.A.3.6(3)	State and Local	Pittman	OIE/DEPER/EPLB	NOTE 3(b)	1	06/30/85	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
III.B	EMERGENCY PREPAREDNESS OF STATE AND LOCAL GOVERNMENTS						
III.B.1	Transfer of Responsibilities to FEMA	Milstead	OIE/DEPER/IRDB	NOTE 3(b)		11/30/83	NA
III.B.2	Implementation of NRC and FEMA Responsibilities	-	-	-			
III.B.2(1)	The Licensing Process	Milstead	OIE/DEPER/IRDB	NOTE 3(b)		11/30/83	NA
III.B.2(2)	Federal Guidance	Milstead	OIE/DEPER/IRDB	NOTE 3(b)		11/30/83	NA
III.C	PUBLIC INFORMATION						
III.C.1	Have Information Available for the News Media and the Public	-	-	-			
III.C.1(1)	Review Publicly Available Documents	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.1(2)	Recommend Publication of Additional Information	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.1(3)	Program of Seminars for News Media Personnel	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.2	Develop Policy and Provide Training for Interfacing With the News Media	-	-	-			
III.C.2(1)	Develop Policy and Procedures for Dealing With Briefing Requests	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.C.2(2)	Provide Training for Members of the Technical Staff	Pittman	PA	LI (NOTE 3)		11/30/83	NA
III.D	RADIATION PROTECTION						
III.D.1	Radiation Source Control						
III.D.1.1	Primary Coolant Sources Outside the Containment Structure	-	-	-			
III.D.1.1(1)	Review Information Submitted by Licensees Pertaining to Reducing Leakage from Operating Systems	-	NRR	I	1	12/31/88	
III.D.1.1(2)	Review Information on Provisions for Leak Detection	Emrit	RES/DRA/ARGIB	DROP	1	12/31/88	
III.D.1.1(3)	Develop Proposed System Acceptance Criteria	Emrit	RES/DRA/ARGIB	DROP	1	12/31/88	
III.D.1.2	Radioactive Gas Management	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3	Ventilation System and Radioiodine Adsorber Criteria	-	-	-			
III.D.1.3(1)	Decide Whether Licensees Should Perform Studies and Make Modifications	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3(2)	Review and Revise SRP	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3(3)	Require Licensees to Upgrade Filtration Systems	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.1.3(4)	Sponsor Studies to Evaluate Charcoal Adsorber	Emrit	NRR/DSI/METB	NOTE 3(b)	1	12/31/88	NA
III.D.1.4	Radwaste System Design Features to Aid in Accident Recovery and Decontamination	Emrit	NRR/DSI/METB	DROP	1	12/31/88	NA
III.D.2	Public Radiation Protection Improvement						
III.D.2.1	Radiological Monitoring of Effluents	-	-	-			
III.D.2.1(1)	Evaluate the Feasibility and Perform a Value-Impact Analysis of Modifying Effluent-Monitoring Design Criteria	Emrit	NRR/DSI/METB	LOW	2	12/31/85	NA
III.D.2.1(2)	Study the Feasibility of Requiring the Development of Effective Means for Monitoring and Sampling Noble Gases and Radioiodine Released to the Atmosphere	Emrit	NRR/DSI/METB	LOW	2	12/31/85	NA
III.D.2.1(3)	Revise Regulatory Guides	Emrit	NRR/DSI/METB	LOW	2	12/31/85	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
III.D.2.2	Radioiodine, Carbon-14, and Tritium Pathway Dose Analysis	-	-	-			
III.D.2.2(1)	Perform Study of Radioiodine, Carbon-14, and Tritium Behavior	Emrit	NRR/DSI/RAB	NOTE 3(b)	2	12/31/85	NA
III.D.2.2(2)	Evaluate Data Collected at Quad Cities	Emrit	NRR/DSI/RAB	III.D.2.5	2	12/31/85	NA
III.D.2.2(3)	Determine the Distribution of the Chemical Species of Radioiodine in Air-Water-Steam Mixtures	Emrit	NRR/DSI/RAB	III.D.2.5	2	12/31/85	NA
III.D.2.2(4)	Revise SRP and Regulatory Guides	Emrit	NRR/DSI/RAB	III.D.2.5	2	12/31/85	NA
III.D.2.3	Liquid Pathway Radiological Control	-	-	-			
III.D.2.3(1)	Develop Procedures to Discriminate Between Sites/Plants	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.3(2)	Discriminate Between Sites and Plants That Require Consideration of Liquid Pathway Interdiction Techniques	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.3(3)	Establish Feasible Method of Pathway Interdiction	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.3(4)	Prepare a Summary Assessment	Emrit	NRR/DE/EHEB	NOTE 3(b)	2	12/31/85	NA
III.D.2.4	Offsite Dose Measurements	-	-	-			
III.D.2.4(1)	Study Feasibility of Environmental Monitors	V'Molen	NRR/DSI/RAB	NOTE 3(b)	2	12/31/85	NA
III.D.2.4(2)	Place 50 TLDs Around Each Site	V'Molen	OIE/DRP/ORPB	LI (NOTE 3)	2	12/31/85	NA
III.D.2.5	Offsite Dose Calculation Manual	V'Molen	NRR/DSI/RAB	NOTE 3(b)	2	12/31/85	NA
III.D.2.6	Independent Radiological Measurements	V'Molen	OIE/DRP/ORPB	LI (NOTE 3)	2	12/31/85	NA
III.D.3	Worker Radiation Protection Improvement						
III.D.3.1	Radiation Protection Plans	V'Molen	NRR/DSI/RAB	NOTE 3(b)	3	12/31/87	NA
III.D.3.2	Health Physics Improvements	-	-	-			
III.D.3.2(1)	Amend 10 CFR 20	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(2)	Issue a Regulatory Guide	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(3)	Develop Standard Performance Criteria	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(4)	Develop Method for Testing and Certifying Air-Purifying Respirators	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.3	In-plant Radiation Monitoring	-	-	-			
III.D.3.3(1)	Issue Letter Requiring Improved Radiation Sampling Instrumentation	-	NRR/DL	I	2		F-69
III.D.3.3(2)	Set Criteria Requiring Licensees to Evaluate Need for Additional Survey Equipment	-	NRR	NOTE 3(a)	2	12/31/86	NA
III.D.3.3(3)	Issue a Rule Change Providing Acceptable Methods for Calibration of Radiation-Monitoring Instruments	-	RES	NOTE 3(a)	2	12/31/86	NA
III.D.3.3(4)	Issue a Regulatory Guide	-	RES	NOTE 3(a)	2	12/31/86	NA
III.D.3.4	Control Room Habitability	-	NRR/DL	I			F-70
III.D.3.5	Radiation Worker Exposure	-	-	-			
III.D.3.5(1)	Develop Format for Data To Be Collected by Utilities Regarding Total Radiation Exposure to Workers	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA
III.D.3.5(2)	Investigative Methods of Obtaining Employee Health Data by Nonlegislative Means	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA
III.D.3.5(3)	Revise 10 CFR 20	V'Molen	RES/DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA
IV.A	STRENGTHEN ENFORCEMENT PROCESS						
IV.A.1	Seek Legislative Authority	Emrit	GC	LI (NOTE 3)		11/30/83	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
IV.A.2	Revise Enforcement Policy	Emrit	OIE/ES	LI (NOTE 3)		11/30/83	NA
IV.B	ISSUANCE OF INSTRUCTIONS AND INFORMATION TO LICENSEES						
IV.B.1	Revise Practices for Issuance of Instructions and Information to Licensees	Emrit	OIE/DEPER	LI (NOTE 3)		11/30/83	NA
IV.C	EXTEND LESSONS LEARNED TO LICENSED ACTIVITIES OTHER THAN POWER REACTORS						
IV.C.1	Extend Lessons Learned from TMI to Other NRC Programs	Emrit	NMSS/WM	NOTE 3(b)		11/30/83	NA
IV.D	NRC STAFF TRAINING						
IV.D.1	NRC Staff Training	Emrit	ADM/MDTS	LI (NOTE 3)		11/30/83	NA
IV.E	SAFETY DECISION-MAKING						
IV.E.1	Expand Research on Quantification of Safety Decision-Making	Colmar	RES/DRA/RABR	LI (NOTE 3)	2	12/31/86	NA
IV.E.2	Plan for Early Resolution of Safety Issues	Emrit	NRR/DST/SPEB	LI (NOTE 3)	2	12/31/86	NA
IV.E.3	Plan for Resolving Issues at the CP Stage	Colmar	RES/DRA/RABR	LI (NOTE 5)	2	12/31/86	NA
IV.E.4	Resolve Generic Issues by Rulemaking	Colmar	RES/DRA/RABR	LI (NOTE 3)	2	12/31/86	NA
IV.E.5	Assess Currently Operating Reactors	Matthews	NRR/DL/SEPB	NOTE 3(b)	2	12/31/86	NA
IV.F	FINANCIAL DISINCENTIVES TO SAFETY						
IV.F.1	Increased OIE Scrutiny of the Power-Ascension Test Program	Thatcher	OIE/DQASIP	NOTE 3(b)	1	12/31/86	NA
IV.F.2	Evaluate the Impacts of Financial Disincentives to the Safety of Nuclear Power Plants	Matthews	SP	NOTE 3(b)	1	12/31/86	NA
IV.G	IMPROVE SAFETY RULEMAKING PROCEDURES						
IV.G.1	Develop a Public Agenda for Rulemaking	Emrit	ADM/RPB	LI (NOTE 3)	1	12/31/86	NA
IV.G.2	Periodic and Systematic Reevaluation of Existing Rules	Milstead	RES/DRA/RABR	LI (NOTE 3)	1	12/31/86	NA
IV.G.3	Improve Rulemaking Procedures	Milstead	RES/DRA/RABR	LI (NOTE 3)	1	12/31/86	NA
IV.G.4	Study Alternatives for Improved Rulemaking Process	Milstead	RES/DRA/RABR	LI (NOTE 3)	1	12/31/86	NA
IV.H	NRC PARTICIPATION IN THE RADIATION POLICY COUNCIL						
IV.H.1	NRC Participation in the Radiation Policy Council	Sege	RES/DHSWM/HEBR	LI (NOTE 3)		11/30/83	NA
V.A	DEVELOPMENT OF SAFETY POLICY						
V.A.1	Develop NRC Policy Statement on Safety	Emrit	GC	LI (NOTE 3)		12/31/86	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
V.B	POSSIBLE ELIMINATION OF NONSAFETY RESPONSIBILITIES						
V.B.1	Study and Recommend, as Appropriate, Elimination of Nonsafety Responsibilities	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.C	ADVISORY COMMITTEES						
V.C.1	Strengthen the Role of Advisory Committee on Reactor Safeguards	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.C.2	Study Need for Additional Advisory Committees	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.C.3	Study the Need to Establish an Independent Nuclear Safety Board	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.D	LICENSING PROCESS						
V.D.1	Improve Public and Intervenor Participation in the Hearing Process	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.D.2	Study Construction-During-Adjudication Rules	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.D.3	Reexamine Commission Role in Adjudication	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.D.4	Study the Reform of the Licensing Process	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.E	LEGISLATIVE NEEDS						
V.E.1	Study the Need for TMI-Related Legislation	Emrit	GC	LI (NOTE 5)		12/31/86	NA
V.F	ORGANIZATION AND MANAGEMENT						
V.F.1	Study NRC Top Management Structure and Process	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.2	Reexamine Organization and Functions of the NRC Offices	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.3	Revise Delegations of Authority to Staff	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.4	Clarify and Strengthen the Respective Roles of Chairman, Commission, and Executive Director for Operations	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.F.5	Authority to Delegate Emergency Response Functions to a Single Commissioner	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.G	CONSOLIDATION OF NRC LOCATIONS						
V.G.1	Achieve Single Location, Long-Term	Emrit	GC	LI (NOTE 3)		12/31/86	NA
V.G.2	Achieve Single Location, Interim	Emrit	GC	LI (NOTE 3)		12/31/86	NA
	TASK ACTION PLAN ITEMS						
A-1	Water Hammer (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	NA
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	D-10
A-3	Westinghouse Steam Generator Tube Integrity (former USI)	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	12/31/88	
A-4	CE Steam Generator Tube Integrity (former USI)	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	12/31/88	

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
A-5	B&W Steam Generator Tube Integrity (former USI)	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	12/31/88	
A-6	Mark I Short-Term Program (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	
A-7	Mark I Long-Term Program (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	D-01
A-8	Mark II Containment Pool Dyanmic Loads Long-Term Program (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	NA
A-9	ATWS (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	
A-10	BWR Feedwater Nozzle Cracking (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	B-25
A-11	Reactor Vessel Materials Toughness (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	NA
A-13	Snubber Operability Assurance	Emrit	NRR/DE/MEB	NOTE 3(a)	1	06/30/91	
A-14	Flaw Detection	Matthews	NRR/DE/MTEB	DROP		11/30/83	NA
A-15	Primary Coolant System Decontamination and Steam Generator Chemical Cleaning	Pittman	NRR/DE/CHEB	NOTE 3(b)		11/30/83	NA
A-16	Steam Effects on BWR Core Spray Distribution	Emrit	NRR/DSI/CPB	NOTE 3(a)		11/30/83	D-12
A-17	Systems Interactions in Nuclear Power Plants (former (USI)	Emrit	RES/DSIR/EIB	NOTE 3(b)	1	12/31/89	NA
A-18	Pipe Rupture Design Criteria	Emrit	NRR/DE/MEB	DROP		11/30/83	NA
A-19	Digital Computer Protection System	Milstead	RES/DSR/HFB	LI (NOTE 5)	1	06/30/91	NA
A-20	Impacts of the Coal Fuel Cycle	-	NRR/DE/EHEB	LI (NOTE 5)		11/30/83	NA
A-21	Main Steamline Break Inside Containment - Evaluation of Environmental Conditions for Equipment Qualification	V'Molen	NRR/DSI/CSB	LOW		11/30/83	NA
A-22	PWR Main Steamline Break - Core, Reactor Vessel and Containment Building Response	V'Molen	NRR/DSI/CSB	DROP		11/30/83	NA
A-23	Containment Leak Testing	Matthews	NRR/DSI/CSB	RI (NOTE 5)		11/30/83	
A-24	Qualification of Class 1E Safety-Related Equipment (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	B-60
A-25	Non-Safety Loads on Class 1E Power Sources	Thatcher	NRR/DSI/PSB	NOTE 3(a)		11/30/83	
A-26	Reactor Vessel Pressure Transient Protection (former (USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	B-04
A-27	Reload Applications	-	NRR/DSI/CPB	LI (NOTE 5)		11/30/83	NA
A-28	Increase in Spent Fuel Pool Storage Capacity	Colmar	NRR/DE/SGEB	NOTE 3(a)		11/30/83	
A-29	Nuclear Power Plant Design for the Reduction of Vulnerability to Industrial Sabotage	Colmar	RES/DRPS/RPSI	NOTE 3(b)	1	12/31/89	NA
A-30	Adequacy of Safety-Related DC Power Supplies	Sege	NRR/DSI/PSB	128	1	12/31/86	NA
A-31	RHR Shutdown Requirements (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	
A-32	Missile Effects	Pittman	NRR/DE/MTEB	A-37, A-38, B-68		11/30/83	NA
A-33	NEPA Review of Accident Risks	-	NRR/DSI/AEB	EI(NOTE 3)		11/30/83	NA
A-34	Instruments for Monitoring Radiation and Process Variables During Accidents	V'Molen	NRR/DSI/ICSB	II.F.3		11/30/83	NA
A-35	Adequacy of Offsite Power Systems	Emrit	NRR/DSI/PSB	NOTE 3(a)	1	12/31/94	
A-36	Control of Heavy Loads Near Spent Fuel (former USI)	Emrit	NRR/DSI/GIB	NOTE 3(a)	1	06/30/85	C-10, C-15
A-37	Turbine Missiles	Pittman	NRR/DE/MTEB	DROP		11/30/83	NA
A-38	Tornado Missiles	Sege	NRR/DSI/ASB	LOW	1	12/31/94	NA
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
A-40	Seismic Design Criteria (former USI)	Emrit	RES/DSIR/EIB	NOTE 3(a)	1	12/31/89	NA
A-41	Long-Term Seismic Program	Colmar	NRR/DE/MEB	NOTE 3(b)	1	12/31/84	NA
A-42	Pipe Cracks in Boiling Water Reactors (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	06/30/85	B-05
A-43	Containment Emergency Sump Performance (former USI)	Emrit	NRR/DST/GIB	NOTE 3(a)	1	12/31/87	
A-44	Station Blackout (former USI)	Emrit	RES/DRPS/RPSI	NOTE 3(a)	1	06/30/88	
A-45	Shutdown Decay Heat Removal Requirements (former USI)	Emrit	RES/DRPS/RPSI	NOTE 3(b)	1	12/31/88	NA
A-46	Seismic Qualification of Equipment in Operating Plants (former USI)	Emrit	NRR/DSRO/EIB	NOTE 3(a)	1	12/31/87	
A-47	Safety Implications of Control Systems (former USI)	Emrit	RES/DSIR/EIB	NOTE 3(a)	1	12/31/89	
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	Emrit	NRR/DSIR/SAIB	NOTE 3(a)	1	06/30/89	
A-49	Pressurized Thermal Shock (former USI)	Emrit	NRR/DSRO/RSIB	NOTE 3(a)	1	12/31/87	A-21
B-1	Environmental Technical Specifications	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-2	Forecasting Electricity Demand	-	NRR	EI (NOTE 3)		11/30/83	NA
B-3	Event Categorization	-	NRR/DSI/RSB	LI (NOTE 3)		11/30/83	NA
B-4	ECCS Reliability	Emrit	NRR/DSI/RSB	II.E.3.2		11/30/83	NA
B-5	Ductility of Two-Way Slabs and Shells and Buckling Behavior of Steel Containments	Thatcher	RES/DE/EIB	NOTE 3(b)	1	06/30/88	NA
B-6	Loads, Load Combinations, Stress Limits	Pittman	NRR/DSRO/EIB	119.1		12/31/87	NA
B-7	Secondary Accident Consequence Modeling	-	NRR/DSI/AEB	LI (NOTE 3)		11/30/83	NA
B-8	Locking Out of ECCS Power Operated Valves	Riggs	NRR/DSI/RSB	DROP	1	12/31/94	NA
B-9	Electrical Cable Penetrations of Containment	Emrit	NRR/DSI/PSB	NOTE 3(b)		11/30/83	NA
B-10	Behavior of BWR Mark III Containments	V'Molen	NRR/DSI/CSB	NOTE 3(a)	1	12/31/84	NA
B-11	Subcompartment Standard Problems	-	NRR/DSI/CSB	LI (NOTE 5)		11/30/83	NA
B-12	Containment Cooling Requirements (Non-LOCA)	Emrit	NRR/DSI/CSB	NOTE 3(b)	1	12/31/86	NA
B-13	Marviken Test Data Evaluation	-	NRR/DSI/CSB	LI (NOTE 5)		11/30/83	NA
B-14	Study of Hydrogen Mixing Capability in Containment Post-LOCA	Emrit	NRR/DST/GIB	A-48		11/30/83	NA
B-15	CONTEMPT Computer Code Maintenance	-	NRR/DSI/CSB	LI (NOTE 3)		11/30/83	NA
B-16	Protection Against Postulated Piping Failures in Fluid Systems Outside Containment	Emrit	NRR/DE/MEB	A-18		11/30/83	NA
B-17	Criteria for Safety-Related Operator Actions	Milstead	RES/DST/CIHFB	MEDIUM	2	12/31/86	
B-18	Vortex Suppression Requirements for Containment Sumps	Emrit	NRR/DST/GIB	A-43		11/30/83	NA
B-19	Thermal-Hydraulic Stability	Colmar	NRR/DSI/CPB	NOTE 3(b)		06/30/85	NA
B-20	Standard Problem Analysis	-	RES/DAE/AMBR	LI (NOTE 5)		11/30/83	
B-21	Core Physics	-	NRR/DSI/CPB	LI (NOTE 3)		11/30/83	NA
B-22	LWR Fuel	Emrit	RES/DSIR/RPSIB	DROP	2	06/30/95	NA
B-23	LMFBR Fuel	-	NRR/DSI/CPB	LI (NOTE 3)		11/30/83	NA
B-24	Seismic Qualification of Electrical and Mechanical Equipment	Emrit	NRR	A-46		11/30/83	NA
B-25	Piping Benchmark Problems	-	NRR/DE/MEB	LI (NOTE 5)		11/30/83	
B-26	Structural Integrity of Containment Penetrations	Riggs	NRR/DE/MTEB	NOTE 3(b)	1	12/31/84	NA
B-27	Implementation and Use of Subsection NF	-	NRR/DE/MEB	LI (NOTE 5)		11/30/83	
B-28	Radionuclide/Sediment Transport Program	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-29	Effectiveness of Ultimate Heat Sinks	Pittman	NRR/DE/EHEB	LI (NOTE 3)	1	06/30/91	NA
B-30	Design Basis Floods and Probability	-	NRR/DE/EHEB	LI (NOTE 5)		11/30/83	
B-31	Dam Failure Model	Milstead	NRR/DE/SGEB	LI (NOTE 3)	1	06/30/89	NA
B-32	Ice Effects on Safety-Related Water Supplies	Pittman	NRR/DE/EHEB	153	1	06/30/91	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
B-33	Dose Assessment Methodology	-	NRR/DSI/RAB	LI (NOTE 3)		11/30/83	NA
B-34	Occupational Radiation Exposure Reduction	Emrit	NRR/DSI/RAB	III.D.3.1		11/30/83	NA
B-35	Confirmation of Appendix I Models for Calculations of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Light Water Cooled Power Reactors	-	NRR/DSI/METB	LI (NOTE 5)		11/30/83	
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and for Normal Ventilation Systems	Emrit	NRR/DSI/METB	NOTE 3(a)		11/30/83	
B-37	Chemical Discharges to Receiving Waters	-	NRR/DE/EHEB	EI (NOTE 5)		11/30/83	
B-38	Reconnaissance Level Investigations	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-39	Transmission Lines	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-40	Effects of Power Plant Entrainment on Plankton	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-41	Impacts on Fisheries	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
B-42	Socioeconomic Environmental Impacts	-	NRR/DE/SAB	EI (NOTE 3)		11/30/83	NA
B-43	Value of Aerial Photographs for Site Evaluation	-	NRR/DE/EHEB	EI (NOTE 5)		11/30/83	
B-44	Forecasts of Generating Costs of Coal and Nuclear Plants	-	NRR/DE/SAB	EI (NOTE 3)		11/30/83	NA
B-45	Need for Power - Energy Conservation	-	NRR/DE/SAB	EI (NOTE 3)		11/30/83	NA
B-46	Cost of Alternatives in Environmental Design	-	NRR/DE/SAB	EI (NOTE 3)		11/30/83	NA
B-47	Inservice Inspection of Supports-Classes 1, 2, 3, and MC Components	Colmar	NRR/DE/MTEB	DROP		11/30/83	NA
B-48	BWR Control Rod Drive Mechanical Failures	Emrit	NRR/DE/MTEB	NOTE 3(b)		11/30/83	
B-49	Inservice Inspection Criteria and Corrosion Prevention Criteria for Containments	-	NRR	LI (NOTE 5)		11/30/83	
B-50	Post-Operating Basis Earthquake Inspection	Colmar	NRR/DE/SGEB	RI (NOTE 3)	1	06/30/85	NA
B-51	Assessment of Inelastic Analysis Techniques for Equipment and Components	Emrit	NRR/DE/MEB	A-40		11/30/83	NA
B-52	Fuel Assembly Seismic and LOCA Responses	Emrit	NRR/DST/GIB	A-2		11/30/83	NA
B-53	Load Break Switch	Sege	NRR/DSI/PSB	RI (NOTE 3)		11/30/83	
B-54	Ice Condenser Containments	Milstead	NRR/DSI/CSB	NOTE 3(b)	1	12/31/84	NA
B-55	Improved Reliability of Target Rock Safety Relief Valves	V'Molen	NRR/DE/EMEB	MEDIUM		11/30/83	
B-56	Diesel Reliability	Milstead	RES/DRPS/RPSI	NOTE 3(a)	2	06/30/95	D-19
B-57	Station Blackout	Emrit	NRR/DST/GIB	A-44		11/30/83	
B-58	Passive Mechanical Failures	Colmar	NRR/DE/EQB	NOTE 3(b)	1	12/31/85	NA
B-59	(N-1) Loop Operation in BWRs and PWRs	Colmar	NRR/DSI/RSB	RI (NOTE 3)	1	06/30/85	E-04,E-05
B-60	Loose Parts Monitoring Systems	Emrit	NRR/DSI/CPB	NOTE 3(b)	1	12/31/84	NA
B-61	Allowable ECCS Equipment Outage Periods	Pittman	RES/DST/PRAB	MEDIUM		11/30/83	
B-62	Reexamination of Technical Bases for Establishing SLs, LSSSs, and Reactor Protection System Trip Functions	-	NRR/DSI/CPB	LI (NOTE 3)		11/30/83	NA
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	Emrit	NRR/DE/MEB	NOTE 3(a)		11/30/83	
B-64	Decommissioning of Reactors	Colmar	RES/DE/MEB	NOTE 3(a)	2	06/30/95	NA
B-65	Iodine Spiking	Milstead	NRR/DSI/AEB	DROP	2	12/31/84	NA
B-66	Control Room Infiltration Measurements	Matthews	NRR/DSI/AEB	NOTE 3(a)		11/30/83	
B-67	Effluent and Process Monitoring Instrumentation	Colmar	NRR/DSI/METB	III.D.2.1		11/30/83	NA
B-68	Pump Overspeed During LOCA	Riani	NRR/DSI/ASB	DROP		11/30/83	NA
B-69	ECCS Leakage Ex-Containment	Riani	NRR/DSI/METB	III.D.1.1(1)		11/30/83	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
B-70	Power Grid Frequency Degradation and Effect on Primary Coolant Pumps	Emrit	NRR/DSI/PSB	NOTE 3(b)		11/30/83	
B-71	Incident Response	Riani	NRR	III.A.3.1		11/30/83	NA
B-72	Health Effects and Life Shortening from Uranium and Coal Fuel Cycles	-	NRR/DSI/RAB	LI (NOTE 5)		11/30/83	NA
B-73	Monitoring for Excessive Vibration Inside the Reactor Pressure Vessel	Thatcher	NRR/DE/MEB	C-12		11/30/83	NA
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	Milstead	NRR/DE/EQB	NOTE 3(a)		11/30/83	
C-2	Study of Containment Depressurization by Inadvertent Spray Operation to Determine Adequacy of Containment External Design Pressure	Emrit	NRR/DSI/CSB	NOTE 3(b)		11/30/83	NA
C-3	Insulation Usage Within Containment	Emrit	NRR/DST/GIB	A-43	1	06/30/91	NA
C-4	Statistical Methods for ECCS Analysis	Riggs	NRR/DSRO/SPEB	RI (NOTE 3)	1	06/30/86	NA
C-5	Decay Heat Update	Riggs	NRR/DSRO/SPEB	RI (NOTE 3)	1	06/30/86	NA
C-6	LOCA Heat Sources	Riggs	NRR/DSRO/SPEB	RI (NOTE 3)	1	06/30/86	NA
C-7	PWR System Piping	Emrit	NRR/DE/MTEB	NOTE 3(b)		11/30/83	NA
C-8	Main Steam Line Leakage Control Systems	Milstead	RES/DRPS/RPSI	NOTE 3(b)	1	06/30/90	NA
C-9	RHR Heat Exchanger Tube Failures	V'Molen	NRR/DSI/RSB	DROP		11/30/83	NA
C-10	Effective Operation of Containment Sprays in a LOCA	Emrit	NRR/DSI/AEB	NOTE 3(a)		11/30/83	NA
C-11	Assessment of Failure and Reliability of Pumps and Valves	Emrit	NRR/DE/MEB	NOTE 3(b)		12/31/85	NA
C-12	Primary System Vibration Assessment	Thatcher	NRR/DE/MEB	NOTE 3(b)		11/30/83	NA
C-13	Non-Random Failures	Emrit	NRR/DST/GIB	A-17	1	06/30/91	NA
C-14	Storm Surge Model for Coastal Sites	Emrit	NRR/DE/EHEB	LI (NOTE 3)		06/30/88	NA
C-15	NUREG Report for Liquid Tank Failure Analysis	-	NRR/DE/EHEB	LI (NOTE 3)		11/30/83	NA
C-16	Assessment of Agricultural Land in Relation to Power Plant Siting and Cooling System Selection	-	NRR/DE/EHEB	EI (NOTE 3)		11/30/83	NA
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	Emrit	NRR/DSI/METB	NOTE 3(a)		11/30/83	NA
D-1	Advisability of a Seismic Scram	Thatcher	RES/DET/MSEB	LOW		11/30/83	NA
D-2	Emergency Core Cooling System Capability for Future Plants	Emrit	RES/DRA/ARGIB	DROP		12/31/88	NA
D-3	Control Rod Drop Accident	Emrit	NRR/DSI/CPB	NOTE 3(b)		11/30/83	NA
	NEW GENERIC ISSUES						
1.	Failures in Air-Monitoring, Air-Cleaning, and Ventilating Systems	Emrit	NRR/DSI/METB	DROP		11/30/83	NA
2.	Failure of Protective Devices on Essential Equipment	Diab	RES/DSIR/EIB	DROP	2	06/30/95	NA
3.	Set Point Drift in Instrumentation	Emrit	NRR/DSIR/RPSIB	NOTE 3(b)	1	06/30/86	NA
4.	End-of-Life and Maintenance Criteria	Thatcher	NRR/DE/EQB	NOTE 3(b)		11/30/83	NA
5.	Design Check and Audit of Balance-of-Plant Equipment	Pittman	NRR/DSI/ASB	I.F.1		11/30/83	NA
6.	Separation of Control Rod from Its Drive and BWR High Rod Worth Events	V'Molen	NRR/DSI/CPB	NOTE 3(b)	1	12/31/94	NA
7.	Failures Due to Flow-Induced Vibrations	V'Molen	NRR/DSI/RSB	DROP	1	06/30/91	NA
8.	Inadvertent Actuation of Safety Injection in PWRs	Colmar	NRR/DSI/RSB	I.C.1		11/30/83	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
9.	Reevaluation of Reactor Coolant Pump Trip Criteria	Emrit	NRR/DSI/RSB	II.K.3(5)		11/30/83	NA
10.	Surveillance and Maintenance of TIP Isolation Valves and Squib Charges	Riggs	NRR/DSI/ICSB	DROP		11/30/83	NA
11.	Turbine Disc Cracking	Pittman	NRR/DE/MTEB	A-37		11/30/83	NA
12.	BWR Jet Pump Integrity	Sege	NRR/DE/MTEB, MEB	NOTE 3(b)	1	12/31/84	NA
13.	Small Break LOCA from Extended Overheating of Pressurizer Heaters	Riani	NRR/DSI/RSB	DROP		11/30/83	NA
14.	PWR Pipe Cracks	Emrit	NRR/DE/MTEB	NOTE 3(b)	2	12/31/94	NA
15.	Radiation Effects on Reactor Vessel Supports	Emrit	RES/DET/EMMEB	HIGH	2	12/31/89	
16.	BWR Main Steam Isolation Valve Leakage Control Systems	Milstead	NRR/DSI/ASB	C-8		11/30/83	NA
17.	Loss of Offsite Power Subsequent to a LOCA	Colmar	NRR/DSI/PSB, ICSB	DROP		11/30/83	NA
18.	Steam Line Break with Consequential Small LOCA	Riggs	NRR/DSI/RSB	I.C.1		11/30/83	NA
19.	Safety Implications of Nonsafety Instrument and Control Power Supply Bus	Sege	NRR/DST/GIB	A-47		11/30/83	NA
20.	Effects of Electromagnetic Pulse on Nuclear Power Plants	Thatcher	NRR/DSI/ICSB	NOTE 3(b)	1	06/30/84	NA
21.	Vibration Qualification of Equipment	Riggs	NRR/DE/EIB	DROP	2	06/30/91	NA
22.	Inadvertent Boron Dilution Events	V'Molen	NRR/DSI/RSB	NOTE 3(b)	2	12/31/94	NA
23.	Reactor Coolant Pump Seal Failures	Riggs	RES/DET/GSIB	HIGH		11/30/83	
24.	Automatic ECCS Switchover to Recirculation	Milstead	RES/DET/GSIB	MEDIUM	2	06/30/95	
25.	Automatic Air Header Dump on BWR Scram System	Milstead	NRR/DSI/RSB	NOTE 3(a)		11/30/83	
26.	Diesel Generator Loading Problems Related to SIS Reset on Loss of Offsite Power	Emrit	NRR/DSI/ASB	17		11/30/83	NA
27.	Manual vs. Automated Actions	Pittman	NRR/DSI/RSB	B-17		11/30/83	NA
28.	Pressurized Thermal Shock	Emrit	NRR/DST/GIB	A-49		11/30/83	NA
29.	Bolting Degradation or Failure in Nuclear Power Plants	V'Molen	RES/DSIR/EIB	NOTE 3(b)	2	06/30/95	NA
30.	Potential Generator Missiles - Generator Rotor Retaining Rings	Pittman	NRR/DE/MEB	DROP	1	12/31/85	NA
31.	Natural Circulation Cooldown	Riggs	NRR/DSI/RSB	I.C.1		11/30/83	NA
32.	Flow Blockage in Essential Equipment Caused by Corbicula	Emrit	NRR/DSI/ASB	51		11/30/83	NA
33.	Correcting Atmospheric Dump Valve Opening Upon Loss of Integrated Control System Power	Pittman	NRR/DSI/ICSB	A-47		11/30/83	NA
34.	RCS Leak	Riggs	NRR/DHFS/PSRB	DROP	1	06/30/84	NA
35.	Degradation of Internal Appurtenances in LWRs	V'Molen	NRR/DSI/CPB, RSB	LOW	1	06/30/85	NA
36.	Loss of Service Water	Colmar	NRR/DSI/ASB, AEB, RSB	NOTE 3(b)	3	06/30/91	NA
37.	Steam Generator Overfill and Combined Primary and Secondary Blowdown	Colmar	NRR/DST/GIB, NRR/DSI/RSB	A-47, I.C.1(2)	1	06/30/85	NA
38.	Potential Recirculation System Failure as a Consequence of Ingestion of Containment Paint Flakes or Other Fine Debris	Emrit	RES/DSIR/RPSIB	DROP	2	06/30/95	NA
39.	Potential for Unacceptable Interaction Between the CRD System and Non-Essential Control Air System	Pittman	NRR/DSI/ASB	25	1	06/30/95	NA
40.	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	Colmar	NRR/DSI/ASB	NOTE 3(a)	1	06/30/84	B-65

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
41.	BWR Scram Discharge Volume Systems	V'Molen	NRR/DSI/RSB	NOTE 3(a)		11/30/83	B-58
42.	Combination Primary/Secondary System LOCA	Riggs	NRR/DSI/RSB	I.C.1	1	06/30/85	NA
43.	Reliability of Air Systems	Milstead	RES/DSIR/RPSI	NOTE 3(a)	2	12/31/88	
44.	Failure of Saltwater Cooling System	Milstead	NRR/DSI/ASB	43	1	12/31/88	NA
45.	Inoperability of Instrumentation Due to Extreme Cold Weather	Milstead	NRR/DSI/ICSB	NOTE 3(a)	2	06/30/91	
46.	Loss of 125 Volt DC Bus	Sege	NRR/DSI/PSB	76		11/30/83	NA
47.	Loss of Offsite Power	Thatcher	NRR/DSI/RSB, ASB	NOTE 3(b)		11/30/83	
48.	LCO for Class 1E Vital Instrument Buses in Operating Reactors	Sege	NRR/DSI/PSB	128	1	12/31/86	NA
49.	Interlocks and LCOs for Redundant Class 1E Tie-Breakers	Sege	NRR/DSI/PSB	128	3	06/30/91	NA
50.	Reactor Vessel Level Instrumentation in BWRs	Thatcher	NRR/DSI/RSB, ICSB	NOTE 3(b)	1	12/31/84	NA
51.	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems	Emrit	RES/DE/EIB	NOTE 3(a)	1	12/31/89	
52.	SSW Flow Blockage by Blue Mussels	Emrit	NRR/DSI/ASB	51		11/30/83	NA
53.	Consequences of a Postulated Flow Blockage Incident in a BWR	V'Molen	NRR/DSI/CPB, RSB	DROP	1	12/31/84	NA
54.	Valve Operator-Related Events Occurring During 1978, 1979, and 1980	Colmar	NRR/DE/MEB	II.E.6.1	1	06/30/85	NA
55.	Failure of Class 1E Safety-Related Switchgear Circuit Breakers to Close on Demand	Emrit	NRR/DSI/PSB	DROP	2	06/30/91	NA
56.	Abnormal Transient Operating Guidelines as Applied to a Steam Generator Overfill Event	Colmar	NRR/DHFS/HFEB	A-47, I.D.1		11/30/83	NA
57.	Effects of Fire Protection System Actuation on Safety-Related Equipment	Milstead	RES/DRA/ARGIB	NOTE 3(b)	3	06/30/95	NA
58.	Inadvertent Containment Flooding	Sege	NRR/DSI/ASB, CSB	DROP		11/30/83	
59.	Technical Specification Requirements for Plant Shutdown when Equipment for Safe Shutdown is Degraded or Inoperable	Emrit	NRR/DST/TSIP	RI (NOTE 5)	1	06/30/85	NA
60.	Lamellar Tearing of Reactor Systems Structural Supports	Colmar	NRR/DST/GIB	A-12		11/30/83	NA
61.	SRV Line Break Inside the BWR Wetwell Airspace of Mark I and II Containments	Milstead	NRR/DSI/CSB	NOTE 3(b)	2	12/31/86	NA
62.	Reactor Systems Bolting Applications	Riggs	RES/DSIR/EIB	29	1	12/31/88	NA
63.	Use of Equipment Not Classified as Essential to Safety in BWR Transient Analysis	Pittman	RES/DRA/ARGIB	DROP	1	06/30/90	NA
64.	Identification of Protection System Instrument Sensing Lines	Thatcher	NRR/DSI/ICSB	NOTE 3(b)		11/30/83	
65.	Probability of Core-Melt Due to Component Cooling Water System Failures	V'Molen	NRR/DSI/ASB	23	1	12/31/86	NA
66.	Steam Generator Requirements	Riggs	NRR/DEST/EMTB	NOTE 3(b)	2	12/31/88	NA
67.	Steam Generator Staff Actions	-	-	-		-	
67.2.1	Integrity of Steam Generator Tube Sleeves	Riggs	NRR/DE/MEB	135	4	06/30/94	NA
67.3.1	Steam Generator Overfill	Riggs	NRR/DST/GIB NRR/DSI/RSB	A-47, I.C.1	4	06/30/94	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
67.3.2	Pressurized Thermal Shock	Riggs	NRR/DST/GIB	A-49	4	06/30/94	NA
67.3.3	Improved Accident Monitoring	Riggs	NRR/DSI/ICSB	NOTE 3(a)	4	06/30/94	A-17
67.3.4	Reactor Vessel Inventory Measurement	Riggs	NRR/DSI/CPB	II.F.2	4	06/30/94	NA
67.4.1	RCP Trip	Riggs	NRR/DSI/RSB	II.K.3(5)	4	06/30/94	G-01
67.4.2	Control Room Design Review	Riggs	NRR/DHFS/HFEB	I.D.1	4	06/30/94	F-08
67.4.3	Emergency Operating Procedures	Riggs	NRC/DHFS/PSRB	I.C.1	4	06/30/94	F-05
67.5.1	Reassessment of Radiological Consequences	Riggs	RES/DRPS/RPSI	LI (NOTE 3)	4	06/30/94	NA
67.5.2	Reevaluation of SGTR Design Basis	Riggs	RES/DRPS/RPSI	LI (67.5.1)	4	06/30/94	NA
67.5.3	Secondary System Isolation	Riggs	NRR/DSI/RSB	DROP	4	06/30/94	NA
67.6.0	Organizational Responses	Riggs	OIE/DEPER/IRDB	III.A.3	4	06/30/94	NA
67.7.0	Improved Eddy Current Tests	Riggs	RES/DE/EIB	135	4	06/30/94	NA
67.8.0	Denting Criteria	Riggs	NRR/DE/MTEB	135	4	06/30/94	NA
67.9.0	Reactor Coolant System Pressure Control	Riggs	NRR/DSI/GIB NRR/DSI/RSB	A-45, I.C.1 (2,3)	4	06/30/94	NA
67.10.0	Supplemental Tube Inspections	Riggs	NRR/DL/ORAB	LI (NOTE 5)	4	06/30/94	NA
68.	Postulated Loss of Auxiliary Feedwater System Resulting from Turbine-Driven Auxiliary Feedwater Pump Steam Supply Line Rupture	Pittman	NRR/DSI/ASB	124	3	06/30/91	NA
69.	Make-up Nozzle Cracking in B&W Plants	Colmar	NRR/DE/MEB, MTEB	NOTE 3(b)	1	12/31/84	B43
70.	PORV and Block Valve Reliability	Riggs	RES/DE/EIB	NOTE 3(a)	3	06/30/91	
71.	Failure of Resin Demineralizer Systems and Their Effects on Nuclear Power Plant Safety	Pittman	RES/DRA/ARGIB	LOW	1	06/30/90	NA
72.	Control Rod Drive Guide Tube Support Pin Failures	Riggs	RES	DROP	1	06/30/91	NA
73.	Detached Thermal Sleeves	Emrit	RES/DSIR/EIB	NOTE 3(a)	3	06/30/95	NA
74.	Reactor Coolant Activity Limits for Operating Reactors	Milstead	NRR/DSI/AEB	DROP	1	06/30/86	NA
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	Emrit	RES/DRA/ARGIB	NOTE 3(a)	1	06/30/90	B-76,B-77 B-78,B-79 B-80,B-81 B-82,B-85 B-86,B-87 B-88,B-89 B-90,B-91 B-92,B-93
76.	Instrumentation and Control Power Interactions	Zimmerman	RES/DSIR/EIB	DROP	3	06/30/95	NA
77.	Flooding of Safety Equipment Compartments by Back-flow Through Floor Drains	Colmar	RES/DE/EIB	A-17		12/31/87	NA
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	Rourk	RES/DET/GSIB	MEDIUM	2	06/30/95	
79.	Unanalyzed Reactor Vessel Thermal Stress During Natural Convection Cooldown	Colmar	RES/DSIR/EIB	NOTE 3(b)	3	06/30/95	NA
80.	Pipe Break Effects on Control Rod Drive Hydraulic Lines in the Drywells of BWR Mark I and II Containments	V'Molen	NRR/DSI/RSB, ASB, CPB	LOW	1	06/30/91	NA
81.	Impact of Locked Doors and Barriers on Plant and Personnel Safety	Rourk	RES/DSIR/EIB	LOW	4	06/30/95	NA
82.	Beyond Design Basis Accidents in Spent Fuel Pools	V'Molen	RES/DRPS/RPSI	NOTE 3(b)	1	06/30/89	NA
83.	Control Room Habitability	Emrit	RES/DST/AEB	NOTE 1	1	12/31/86	

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
84.	CE PORVs	Riggs	RES/DSIR/RPSI	NOTE 3(b)	2	06/30/90	NA
85.	Reliability of Vacuum Breakers Connected to Steam Discharge Lines Inside BWR Containments	Milstead	NRR/DSI/CSB	DROP	2	06/30/91	NA
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	Emrit	NRR/DEST/EMTB	NOTE 3(a)	1	06/30/88	B-84
87.	Failure of HPCI Steam Line Without Isolation	Pittman	RES/DSIR/EIB	NOTE 3(a)	2	06/30/95	
88.	Earthquakes and Emergency Planning	Riggs	RES/DRA/ARGIB	NOTE 3(b)		12/31/87	NA
89.	Stiff Pipe Clamps	Chang	RES/DSIR/EIB	LOW	2	06/30/95	NA
90.	Technical Specifications for Anticipatory Trips	V'Molen	NRR/DSI/RSB, ICSB	LOW	1	06/30/95	NA
91.	Main Crankshaft Failures in Transamerica DeLaval Emergency Diesel Generators	Emrit	RES/DRA/ARGIB	NOTE 3(b)		12/31/87	NA
92.	Fuel Crumbling During LOCA	V'Molen	NRR/DSI/RSB, CPB	LOW		12/31/84	NA
93.	Steam Binding of Auxiliary Feedwater Pumps	Pittman	RES/DRPS/RPSI	NOTE 3(a)		06/30/88	
94.	Additional Low Temperature Overpressure Protection for Light Water Reactors	Pittman	RES/DSIR/RPSI	NOTE 3(a)		06/30/90	
95.	Loss of Effective Volume for Containment Recirculation Spray	Milstead	RES/DRA/ARGIB	NOTE 3(b)		06/30/90	NA
96.	RHR Suction Valve Testing	Milstead	RES/DRA/ARGIB	105		06/30/90	NA
97.	PWR Reactor Cavity Uncontrolled Exposures	V'Molen	NRR/DSI/RAB	III.D.3.1		06/30/85	NA
98.	CRD Accumulator Check Valve Leakage	Pittman	NRR/DSI/ASB	DROP		06/30/85	NA
99.	RCS/RHR Suction Line Valve Interlock on PWRs	Pittman	RES/DRPS/RPSI	NOTE 3(a)	3	06/30/91	
100.	Once-Through Steam Generator Level	Jackson	RES/DSIR/EIB	DROP	1	06/30/95	NA
101.	BWR Water Level Redundancy	V'Molen	RES/DE/EIB	NOTE 3(b)	1	06/30/89	NA
102.	Human Error in Events Involving Wrong Unit or Wrong Train	Emrit	NRR/DLPQ/LPEB	NOTE 3(b)	2	12/31/88	NA
103.	Design for Probable Maximum Precipitation	Emrit	RES/DE/EIB	NOTE 3(a)	1	12/31/89	NA
104.	Reduction of Boron Dilution Requirements	Pittman	RES/DRA/ARGIB	DROP		12/31/88	NA
105.	Interfacing Systems LOCA at LWRs	Milstead	RES/DE/EIB	NOTE 3(b)	4	06/30/95	NA
106.	Piping and Use of Highly Combustible Gases in Vital Areas	Milstead	RES/DRPS	NOTE 3(b)	2	06/30/95	NA
107.	Main Transformer Failures	Milstead	RES/DRA/ARGIB	LOW	1	06/30/91	NA
108.	BWR Suppression Pool Temperature Limits	Colmar	NRR/DSI/CSB	RI (NOTE 3)		06/30/85	NA
109.	Reactor Vessel Closure Failure	Riggs	RES/DRA/ARGIB	DROP		06/30/90	NA
110.	Equipment Protective Devices on Engineered Safety Features	Diab	RES/DSIR/EIB	DROP	1	06/30/95	NA
111.	Stress Corrosion Cracking of Pressure Boundary Ferritic Steels in Selected Environments	Riggs	NRR/DE/MTEB	LI (NOTE 5)	1	06/30/91	NA
112.	Westinghouse RPS Surveillance Frequencies and Out-of-Service Times	Pittman	NRR/DSI/ICSB	RI (NOTE 3)		12/31/85	NA
113.	Dynamic Qualification Testing of Large Bore Hydraulic Snubbers	Riggs	RES/DSIR/EIB	NOTE 3(b)	2	06/30/95	NA
114.	Seismic-Induced Relay Chatter	Riggs	NRR/DSRO/SPEB	A-46	1	06/30/91	NA
115.	Enhancement of the Reliability of Westinghouse Solid State Protection System	Milstead	RES/DRPS/RPSI	NOTE 3(b)		06/30/89	NA
116.	Accident Management	Pittman	RES/DRA/ARGIB	S		06/30/91	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
117.	Allowable Time for Diverse Simultaneous Equipment Outages	Pittman	RES/DRA/ARGIB	DROP		06/30/90	NA
118.	Tendon Anchorage Failure	Shaukat	RES/DSIR/EIB	NOTE 3(a)	1	06/30/95	NA
119.	Piping Review Committee Recommendations	-	-	-			
119.1	Piping Rupture Requirements and Decoupling of Seismic and LOCA Loads	Riggs	NRR/DE	RI (NOTE 3)	2	06/30/93	NA
119.2	Piping Damping Values	Riggs	NRR/DE	RI (DROP)	2	06/30/93	NA
119.3	Decoupling the OBE from the SSE	Riggs	NRR/DE	RI (S)	2	06/30/93	NA
119.4	BWR Piping Materials	Riggs	NRR/DE	RI (NOTE 5)	2	06/30/93	NA
119.5	Leak Detection Requirements	Riggs	NRR/DE	RI (NOTE 5)	2	06/30/93	NA
120.	On-Line Testability of Protection Systems	Milstead	RES/DRA/ARGIB	NOTE 3(b)	2	06/30/95	NA
121.	Hydrogen Control for Large, Dry PWR Containments	Emrit	RES/DSIR/SAIB	NOTE 3(b)	2	06/30/95	NA
122.	Davis-Besse Loss of All Feedwater Event of June 9, 1985: Short-Term Actions						
122.1	Potential Inability to Remove Reactor Decay Heat	-	-	-			
122.1.a	Failure of Isolation Valves in Closed Position	V'Molen	NRR/DSRO/RSIB	124	3	06/30/91	NA
122.1.b	Recovery of Auxiliary Feedwater	V'Molen	NRR/DSRO/RSIB	124	3	06/30/91	NA
122.1.c.	Interruption of Auxiliary Feedwater Flow	V'Molen	NRR/DSRO/RSIB	124	3	06/30/91	NA
122.2	Initiating Feed-and-Bleed	V'Molen	NRR/DEST/SRXB	NOTE 3(b)	3	06/30/91	NA
122.3	Physical Security System Constraints	V'Molen	NRR/DSRO/SPEB	LOW	3	06/30/91	NA
123.	Deficiencies in the Regulations Governing DBA and Single-Failure Criteria Suggested by the Davis-Besse Event of June 9, 1985	Milstead	RES/DSIR/SAIB	DROP	1	06/30/95	NA
124.	Auxiliary Feedwater System Reliability	Emrit	NRR/DEST/SRXB	NOTE 3(a)	3	06/30/91	
125.	Davis-Besse Loss of All Feedwater Event of June 9, 1985: Long-Term Actions	-	-	-			
125.I.1	Availability of the Shift Technical Advisor	V'Molen	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.I.2	PORV Reliability	-	-	-	6	12/31/89	
125.I.2.a	Need for a Test Program to Establish Reliability of the PORV	V'Molen	NRR/DSRO/SPEB	70	6	12/31/89	NA
125.I.2.b	Need for PORV Surveillance Tests to Confirm Operational Readiness	V'Molen	NRR/DSRO/SPEB	70	6	12/31/89	NA
125.I.2.c	Need for Additional Protection Against PORV Failure	V'Molen	NRR/DSRO/SPEB	DROP	6	12/31/89	NA
125.I.2.d	Capability of the PORV to Support Feed-and-Bleed	V'Molen	NRR/DSRO/SPEB	A-45	6	12/31/89	NA
125.I.3	SPDS Availability	Milstead	RES/DRA/ARGIB	NOTE 3(b)	6	12/31/89	NA
125.I.4	Plant-Specific Simulator	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.I.5	Safety Systems Tested in All Conditions Required by DBA	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.I.6	Valve Torque Limit and Bypass Switch Settings	V'Molen	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.I.7	Operator Training Adequacy	-	-	-			
125.I.7.a	Recover Failed Equipment	Pittman	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.I.7.b	Realistic Hands-On Training	V'Molen	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.I.8	Procedures and Staffing for Reporting to NRC Emergency Response Center	V'Molen	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.1	Need for Additional Actions on AFW Systems	-	-	-			
125.II.1.a	Two-Train AFW Unavailability	V'Molen	NRR/DSRO/SPEB	DROP	6	12/31/89	NA
125.II.1.b	Review Existing AFW Systems for Single Failure	V'Molen	NRR/DSRO/SPEB	124	6	12/31/89	NA
125.II.1.c	NUREG-0737 Reliability Improvements	V'Molen	NRR/DSRO/SPEB	DROP	6	12/31/89	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
125.II.1.d	AFW/Steam and Feedwater Rupture Control System/ICS Interactions in B&W Plants	V'Molen	NRR/DSRO/SPEB	DROP	6	12/31/89	NA
125.II.2	Adequacy of Existing Maintenance Requirements for Safety-Related Systems	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.3	Review Steam/Feedline Break Mitigation Systems for Single Failure	V'Molen	NRR/DSRO/SPEB	DROP	6	12/31/89	NA
125.II.4	Thermal Stress of OTSG Components	Riggs	NRR/DSRO/SPEB	DROP	6	12/31/89	NA
125.II.5	Thermal-Hydraulic Effects of Loss and Restoration of Feedwater on Primary System Components	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	
125.II.6	Reexamine PRA Estimates of Core Damage Risk from Loss of All Feedwater	V'Molen	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.7	Reevaluate Provision to Automatically Isolate Feedwater from Steam Generator During a Line Break	V'Molen	RES/DRPS/RPSI	NOTE 3(b)	6	12/31/89	NA
125.II.8	Reassess Criteria for Feed-and-Bleed Initiation	V'Molen	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.9	Enhanced Feed-and-Bleed Capability	V'Molen	NRR/DSRO/SPEB	DROP	6	12/31/89	NA
125.II.10	Hierarchy of Impromptu Operator Actions	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.11	Recovery of Main Feedwater as Alternative to Auxiliary Feedwater	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.12	Adequacy of Training Regarding PORV Operation	Riggs	RES/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.13	Operator Job Aids	Pittman	NRR/DRA/ARGIB	DROP	6	12/31/89	NA
125.II.14	Remote Operation of Equipment Which Must Now Be Operated Locally	V'Molen	NRR/DSRO/SPEB	LOW	6	12/31/89	NA
126.	Reliability of PWR Main Steam Safety Valves	Riggs	RES/DRA/ARGIB	LI (NOTE 3)		06/30/88	NA
127.	Maintenance and Testing of Manual Valves in Safety-Related Systems	Pittman	RES/DRA/ARGIB	LOW		12/31/87	NA
128.	Electrical Power Reliability	Emrit	RES/DSIR/EIB	NOTE 3(a)	2	06/30/95	
129.	Valve Interlocks to Prevent Vessel Drainage During Shutdown Cooling	Milstead	RES/DRA/ARGIB	DROP		06/30/90	NA
130.	Essential Service Water Pump Failures at Multiplant Sites	Riggs	RES/DSIR/RPSIB	NOTE 3(a)	1	12/31/91	
131.	Potential Seismic Interaction Involving the Movable In-Core Flux Mapping System Used in Westinghouse-Designed Plants	Riggs	RES/DRA/ARGIB	S	1	06/30/91	NA
132.	RHR System Inside Containment	Su	RES/DSIR/SAIB	DROP		12/31/92	NA
133.	Update Policy Statement on Nuclear Plant Staff Working Hours	Pittman	NRR/DLPQ/LHFB	LI (NOTE 3)	1	12/31/91	NA
134.	Rule on Degree and Experience Requirement	Pittman	RES/DRA/RDB	NOTE 3(b)		12/31/89	NA
135.	Steam Generator and Steam Line Overfill	Emrit	RES/DSIR/EIB	NOTE 3(b)	3	06/30/95	NA
136.	Storage and Use of Large Quantities of Cryogenic Combustibles On Site	Milstead	RES/DRA/ARGIB	LI (NOTE 3)		06/30/88	NA
137.	Refueling Cavity Seal Failure	Milstead	RES/DRA/ARGIB	DROP		06/30/90	NA
138.	Deinerting of BWR Mark I and II Containments During Power Operations Upon Discovery of RCS Leakage or a Train of a Safety System Inoperable	Milstead	RES/DSIR/SAIB	LOW	1	06/30/95	NA
139.	Thinning of Carbon Steel Piping in LWRs	Riggs	RES/DRA/ARGIB	RI (NOTE 3)	1	06/30/95	NA
140.	Fission Product Removal Systems	Riggs	RES/DRA/ARGIB	DROP		06/30/90	NA
141.	Large-Break LOCA With Consequential SGTR	Riggs	RES/DRA/ARGIB	DROP		06/30/90	NA

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142.	Leakage Through Electrical Isolators in Instrumentation Circuits	Milstead	RES/DSIR/EIB	NOTE 3(b)	3	06/30/95	NA
143.	Availability of Chilled Water Systems and Room Cooling	Milstead	RES/DRA/ARGIB	NOTE 3(b)	2	06/30/95	NA
144.	Scram Without a Turbine/Generator Trip	Hrabal	RES/DSIR/EIB	LOW	1	06/30/95	NA
145.	Actions to Reduce Common Cause Failures	Rasmuson	RES/DST/PRAB	NOTE 1	1	06/30/95	
146.	Support Flexibility of Equipment and Components	Chang	RES/DSIR/EIB	NOTE 3(b)	2	06/30/95	NA
147.	Fire-Induced Alternate Shutdown/Control Room Panel Interactions	Milstead	RES/DSIR/SAIB	LI (NOTE 3)	1	06/30/94	NA
148.	Smoke Control and Manual Fire-Fighting Effectiveness	Basdekas	RES/DSIR/RPSIB	LI (NOTE 5)		12/31/92	NA
149.	Adequacy of Fire Barriers	Emrit	RES/DSIR/EIB	LOW	1	06/30/95	NA
150.	Overpressurization of Containment Penetrations	Milstead	RES/DSIR/SAIB	DROP	1	06/30/95	NA
151.	Reliability of Anticipated Transient Without SCRAM Recirculation Pump Trip in BWRs	Milstead	RES/DSIR/SAIB	NOTE 3(b)	2	06/30/95	NA
152.	Design Basis for Valves That Might Be Subjected to Significant Blowdown Loads	Emrit	RES/DSIR/EIB	LOW	1	06/30/95	NA
153.	Loss of Essential Service Water in LWRs	Riggs	RES/DRA/ARGIB	NOTE 3(b)		06/30/93	NA
154.	Adequacy of Emergency and Essential Lighting	Woods	RES/DSIR/SAIB	LOW	1	06/30/95	NA
155.	Generic Concerns Arising from TMI-2 Cleanup	-	-	-		-	-
155.1	More Realistic Source Term Assumptions	Emrit	RES/DST/AEB	NOTE 3(a)	2	06/30/95	NA
155.2	Establish Licensing Requirements for Non-Operating Facilities	Emrit	RES/DSIR/EIB	RI (NOTE 5)	2	06/30/95	NA
155.3	Improve Design Requirements for Nuclear Facilities	Emrit	RES/DSIR/EIB	DROP	2	06/30/95	NA
155.4	Improve Criticality Calculations	Emrit	RES/DSIR/EIB	DROP	2	06/30/95	NA
155.5	More Realistic Severe Reactor Accident Scenario	Emrit	RES/DSIR/EIB	DROP	2	06/30/95	NA
155.6	Improve Decontamination Regulations	Emrit	RES/DSIR/EIB	DROP	2	06/30/95	NA
155.7	Improve Decommissioning Regulations	Emrit	RES/DSIR/EIB	DROP	2	06/30/95	NA
156.	Systematic Evaluation Program	-	-	-		-	-
156.1.1	Settlement of Foundations and Buried Equipment	Chang	RES/DSIR/EIB	DROP	4	06/30/95	NA
156.1.2	Dam Integrity and Site Flooding	Chen	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.1.3	Site Hydrology and Ability to Withstand Floods	Chen	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.1.4	Industrial Hazards	Ferrell	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.1.5	Tornado Missiles	Chen	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.1.6	Turbine Missiles	Emrit	RES/DSIR/EIB	DROP	4	06/30/95	NA
156.2.1	Severe Weather Effects on Structures	Chen	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.2.2	Design Codes, Criteria, and Load Combinations	Kirkwood	RES/DSIR/EIB	DROP	4	06/30/95	NA
156.2.3	Containment Design and Inspection	Shaukat	RES/DSIR/EIB	DROP	4	06/30/95	NA
156.2.4	Seismic Design of Structures, Systems, and Components	Chen	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.3.1.1	Shutdown Systems	Woods	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.3.1.2	Electrical Instrumentation and Controls	Woods	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.3.2	Service and Cooling Water Systems	Su	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.3.3	Ventilation Systems	Burdick	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.3.4	Isolation of High and Low Pressure Systems	Burdick	RES/DSIR/SAIB	DROP	4	06/30/95	NA
156.3.5	Automatic ECCS Switchover	Milstead	RES/DSIR/SAIB	24	4	06/30/95	NA
156.3.6.1	Emergency AC Power	Emrit	RES/DSIR/EIB	DROP	4	06/30/95	NA
156.3.6.2	Emergency DC Power	Rourk	RES/DSIR/EIB	LOW	4	06/30/95	NA
156.3.8	Shared Systems	Emrit	RES/DSIR/EIB	DROP	4	06/30/95	NA
156.4.1	RPS and ESFS Isolation	Emrit	RES/DSIR/EIB	142	4	06/30/95	NA
156.4.2	Testing of the RPS and ESFS	Chang	RES/DSIR/SAIB	120	4	06/30/95	NA

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156.6.1	Pipe Break Effects on Systems and Components	Page	RES/DET/GSIB	NOTE 4	4	06/30/95	
157.	Containment Performance	Shaperow	RES/DSIR/SAIB	NOTE 3(b)	1	06/30/95	NA
158.	Performance of Power-Operated Valves Under Design Basis Conditions	Hrabal	RES/DET/GSIB	MEDIUM	1	06/30/95	
159.	Qualification of Safety-Related Pumps While Running on Minimum Flow	Su	RES/DSIR/SAIB	DROP	1	06/30/95	NA
160.	Spurious Actions of Instrumentation Upon Restoration of Power	Rourk	RES/DSIR/EIB	DROP	1	06/30/95	NA
161.	Use of Non-Safety-Related Power Supplies in Safety-Related Circuits	Rourk	RES/DSIR/EIB	DROP	1	06/30/95	NA
162.	Inadequate Technical Specifications for Shared Systems at Multiplant Sites When One Unit Is Shut Down	Cheh	RES/DSIR/SAIB	DROP	1	06/30/95	NA
163.	Multiple Steam Generator Tube Leakage	Burdick	RES/DET/GSIB	NOTE 4		(later)	
164.	Neutron Fluence in Reactor Vessel	Emrit	RES/DSIR/EIB	DROP	1	06/30/95	NA
165.	Safety and Safety/Relief Valve Reliability	Hrabal	RES/DET/GSIB	HIGH	1	06/30/95	NA
166.	Adequacy of Fatigue Life of Metal Components	Emrit	NRR/DE/EMEB	NOTE 1	1	06/30/95	
167.	Hydrogen Storage Facility Separation	Burdick	RES/DSIR/SAIB	LOW	1	06/30/95	NA
168.	Environmental Qualification of Electrical Equipment	Emrit	NRR/DSSA/SPLB	NOTE 1	1	06/30/95	
169.	BWR MSIV Common Mode Failure Due to Loss of Accumulator Pressure	Emrit	RES/DET/GSIB	NOTE 4		(later)	
170.	Fuel Damage Criteria for High Burnup Fuel	Emrit	RES/DET/GSIB	NOTE 2		06/30/95	
171.	ESF Failure from LOOP Subsequent to A LOCA	Rourk	RES/DET/GSIB	HIGH		06/30/95	
	HUMAN FACTORS ISSUES						
HF1	STAFFING AND QUALIFICATIONS						
HF1.1	Shift Staffing	Pittman	RES/DRPS/RHFB	NOTE 3(a)	2	06/30/89	
HF1.2	Engineering Expertise on Shift	Pittman	NRR/DHFT/HFIB	NOTE 3(b)	2	06/30/89	
HF1.3	Guidance on Limits and Conditions of Shift Work	Pittman	NRR/DHFT/HFIB	NOTE 3(b)	2	06/30/89	
HF2	TRAINING						
HF2.1	Evaluate Industry Training	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF2.2	Evaluate INPO Accreditation	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF2.3	Revise SRP Section 13.2	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF3	OPERATOR LICENSING EXAMINATIONS						
HF3.1	Develop Job Knowledge Catalog	Pittman	NRR/DHFT/HFIB	LI (NOTE 3)	2	12/31/87	NA
HF3.2	Develop License Examination Handbook	Pittman	NRR/DHFT/HFIB	LI (NOTE 3)	2	12/31/87	NA
HF3.3	Develop Criteria for Nuclear Power Plant Simulators	Pittman	NRR/DHFT/HFIB	I.A.4.2(4)	2	12/31/87	NA
HF3.4	Examination Requirements	Pittman	NRR/DHFT/HFIB	I.A.2.6(1)	2	12/31/87	NA
HF3.5	Develop Computerized Exam System	Pittman	NRR/DHFT/HFIB	LI (NOTE 3)	2	12/31/87	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
HF4	PROCEDURES						
HF4.1	Inspection Procedure for Upgraded Emergency Operating Procedures	Pittman	NRR/DLPQ/LHFB	NOTE 3(b)	6	06/30/95	NA
HF4.2	Procedures Generation Package Effectiveness Evaluation	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	6	06/30/95	NA
HF4.3	Criteria for Safety-Related Operator Actions	Pittman	NRR/DHFT/HFIB	B-17	6	06/30/95	NA
HF4.4	Guidelines for Upgrading Other Procedures	Pittman	RES/DRPS/RHFB	NOTE 3(b)	6	06/30/95	NA
HF4.5	Application of Automation and Artificial Intelligence	Pittman	NRR/DHFT/HFIB	HF5.2	6	06/30/95	NA
HF5	MAN-MACHINE INTERFACE						
HF5.1	Local Control Stations	Pittman	RES/DRPS/RHFB	NOTE 3(b)	4	06/30/95	NA
HF5.2	Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation	Pittman	RES/DRPS/RHFB	NOTE 3(b)	4	06/30/95	NA
HF5.3	Evaluation of Operational Aid Systems	Pittman	NRR/DHFT/HFIB	HF5.2	4	06/30/95	NA
HF5.4	Computers and Computer Displays	Pittman	NRR/DHFT/HFIB	HF5.2	4	06/30/95	NA
HF6	MANAGEMENT AND ORGANIZATION						
HF6.1	Develop Regulatory Position on Management and Organization	Pittman	NRR/DHFT/HFIB	I.B.1.1 (1,2,3,4)	1	12/31/86	NA
HF6.2	Regulatory Position on Management and Organization at Operating Reactors	Pittman	NRR/DHFT/HFIB	I.B.1.1 (1,2,3,4)	1	12/31/86	NA
HF7	HUMAN RELIABILITY						
HF7.1	Human Error Data Acquisition	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF7.2	Human Error Data Storage and Retrieval	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF7.3	Reliability Evaluation Specialist Aids	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF7.4	Safety Event Analysis Results Applications	Pittman	NRR/DHFT/HFIB	LI (NOTE 5)	1	12/31/86	NA
HF8	Maintenance and Surveillance Program	Pittman	NRR/DLPQ/LPEB	NOTE 3(b)	2	06/30/88	NA
	CHERNOBYL ISSUES						
CH1	ADMINISTRATIVE CONTROLS AND OPERATIONAL PRACTICES						
CH1.1	Administrative Controls to Ensure That Procedures Are Followed and That Procedures Are Adequate	-	-				
CH1.1A	Symptom-Based EOPs	Emrit	NRR/DLPQ/LHFB	LI (NOTE 5)		06/30/89	NA
CH1.1B	Procedure Violations	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH1.2	Approval of Tests and Other Unusual Operations	-	-				
CH1.2A	Test, Change, and Experiment Review Guidelines	Emrit	NRR/DOEA/OTSB	LI (NOTE 5)		06/30/89	NA
CH1.2B	NRC Testing Requirements	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH1.3	Bypassing Safety Systems	-	-				
CH1.3A	Revise Regulatory Guide 1.47	Emrit	RES/DE/EMEB	LI (NOTE 5)		06/30/89	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
CH1.4	Availability of Engineered Safety Features	-	-				
CH1.4A	Engineered Safety Feature Availability	Emrit	NRR/DOEA/OTSB	LI (NOTE 5)		06/30/89	NA
CH1.4B	Technical Specifications Bases	Emrit	NRR/DOEA/OTSB	LI (NOTE 5)		06/30/89	NA
CH1.4C	Low Power and Shutdown	Emrit	RES/DSR/PRAB	LI (NOTE 5)		06/30/89	NA
CH1.5	Operating Staff Attitudes Toward Safety	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH1.6	Management Systems	-	-				
CH1.6A	Assessment of NRC Requirements on Management	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH1.7	Accident Management	-	-				
CH1.7A	Accident Management	Emrit	RES/DSR/HFRB	LI (NOTE 5)		06/30/89	NA
CH2	DESIGN						
CH2.1	Reactivity Accidents	-	-				
CH2.1A	Reactivity Transients	Emrit	RES/DSR/RPSB	LI (NOTE 5)		06/30/89	NA
CH2.2	Accidents at Low Power and at Zero Power	Emrit	RES/DRA/ARGIB	CH1.4		06/30/89	NA
CH2.3	Miltiple-Unit Protection	-	-				
CH2.3A	Control Room Habitability	Emrit	RES/DRA/ARGIB	83		06/30/89	NA
CH2.3B	Contamination Outside Control Room	Emrit	RES/DRA/ARGIB	LI (NOTE 5)		06/30/89	NA
CH2.3C	Smoke Control	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH2.3D	Shared Shutdown Systems	Emrit	RES/DRA/ARGIB	LI (NOTE 5)		06/30/89	NA
CH2.4	Fire Protection	-	-				
CH2.4A	Firefighting With Radiation Present	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH3	CONTAINMENT						
CH3.1	Containment Performance During Severe Accidents	-	-				
CH3.1A	Containment Performance	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH3.2	Filtered Venting	-	-				
CH3.2A	Filtered Venting	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH4	EMERGENCY PLANNING						
CH4.1	Size of the Emergency Planning Zones	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH4.2	Medical Services	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH4.3	Ingestion Pathway Measures	-	-				
CH4.3A	Ingestion Pathway Protective Measures	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH4.4	Decontamination and Relocation	-	-				
CH4.4A	Decontamination	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH4.4B	Relocation	Emrit	RES/DSIR/SAIB	LI (NOTE 5)		06/30/89	NA
CH5	SEVERE ACCIDENT PHENOMENA						
CH5.1	Source Term	-	-				
CH5.1A	Mechanical Dispersal in Fission Product Release	Emrit	RES/DSR/AEB	LI (NOTE 5)		06/30/89	NA
CH5.1B	Stripping in Fission Product Release	Emrit	RES/DSR/AEB	LI (NOTE 5)		06/30/89	NA
CH5.2	Steam Explosions	-	-				
CH5.2A	Steam Explosions	Emrit	RES/DSR/AEB	LI (NOTE 5)		06/30/89	NA
CH5.3	Combustible Gas	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Revision	Latest Issuance Date	MPA No.
CH6	GRAPHITE-MODERATED REACTORS						
CH6.1	Graphite-Moderated Reactors	-	-				
CH6.1A	The Fort St. Vrain Reactor and the Modular HTGR	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH6.1B	Structural Graphite Experiments	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA
CH6.2	Assessment	Emrit	RES/DRA/ARGIB	LI (NOTE 3)		06/30/89	NA

TABLE III

SUMMARY OF THE PRIORITIZATION OF ALL TMI ACTION PLAN ITEMS, TASK ACTION PLAN ITEMS, NEW GENERIC ISSUES, HUMAN FACTORS ISSUES, AND CHERNOBYL ISSUES

Legend

NOTES:
1 - Possible Resolution Identified for Evaluation
2 - Resolution Available
3 - Resolution Resulted in either the Establishment of New Requirements or No New Requirements
4 - Issues to be Prioritized in the Future
5 - Issues that are not GSIs but Should be Assigned Resources for Completion

DROP	- GSI Dropped from Further Pursuit
EI	- Environmental Issue
GSI	- Generic Safety Issue
HIGH	- High Safety Priority
I	- TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737
LI	- Licensing Issue
LOW	- Low Safety Priority
MEDIUM	- Medium Safety Priority
RI	- Regulatory Impact Issue
USI	- Unresolved Safety Issue

TABLE III (Continued)

ACTION ITEM/ISSUE GROUP	I	COVERED IN OTHER ISSUES	RESOLVED STAGES NOTE 1	NOTE 2	NOTE 3	USI	HIGH	MEDIUM	LOW	DROP	NOTE 4	NOTE 5	TOTAL
TMI ACTION PLAN ITEMS (369)													
GSI	84	46	0	0	135	0	0	0	12	9	-	-	286
LI	-	0	-	-	75	-	-	-	-	-	-	8	83
TASK ACTION PLAN ITEMS (142)													
USI	-	-	-	-	27	0	-	-	-	-	-	-	27
GSI	-	20	0	0	33	-	0	3	3	11	0	-	70
RI	-	-	-	-	6	-	-	-	-	-	-	1	7
LI	-	-	-	-	11	-	-	-	-	-	-	12	23
EI	-	-	-	-	13	-	-	-	-	-	-	2	15
NEW GENERIC ISSUES (249)													
GSI	-	54	4	1	62	0	4	3	18	81	3	-	230
RI	-	-	-	-	4	-	-	-	-	1	-	5	10
LI	-	1	-	-	5	-	-	-	-	-	-	3	9
HUMAN FACTORS (27)													
GSI	-	8	0	0	8	0	0	0	0	0	-	-	16
LI	-	-	-	-	3	-	-	-	-	-	-	8	11
CHERNOBYL ISSUES (32)													
LI	-	2	-	-	7	-	-	-	-	-	-	23	39
TOTAL:	84	131	4	1	389	0	4	6	33	102	3	62	819

TASK I.D: CONTROL ROOM DESIGN

The objective of this task was to improve the ability of nuclear power plant control room operators to prevent accidents or cope with accidents if they occur by improving the information provided to them.

ITEM I.D.1: CONTROL ROOM DESIGN REVIEWS

This item was clarified in NUREG-0737,[98] requirements were issued, and MPA F-08 was established by DL for implementation purposes.

ITEM I.D.2: PLANT SAFETY PARAMETER DISPLAY CONSOLE

DESCRIPTION

This item was clarified in NUREG-0737,[98] requirements were issued, and MPA F-09 was established by DL for implementation purposes. Generic Letter No. 82-33[376] transmitted Supplement 1 to NUREG-0737[98] to further clarify the TMI action items related to emergency response capability, including Item I.D.2. This Supplement 1 included the fundamental requirements for emergency response capability from the wide range of regulatory documents issued on the subject. It was written at the conceptual level to allow for a high degree of flexibility in scheduling and design. In recognition of the interrelationships among the action items addressed in Supplement 1,[98] the staff made allowance for each licensee to negotiate a reasonable schedule for implementing its emergency response capability. However, the staff identified the SPDS as an improvement to the control room that should not be delayed by progress on other initiatives.

CONCLUSION

The staff evaluated licensee/applicant implementation of the SPDS requirements at 57 units and found that a large percentage of designs did not satisfy requirements identified in Supplement 1 to NUREG-0737.[98] Generic Letter 89-06[1205] (enclosing NUREG-1342[1206]) was issued to inform licensees of the staff's findings to aid in implementing SPDS requirements. NUREG-1342[1206] describes: (1) methods used by some licensees/applicants to implement SPDS requirements in a manner found acceptable by the staff; and (2) design features that the staff found unacceptable, with the staff's reasons. The information in NUREG-1342[1206] did not constitute new requirements; Supplement 1 to NUREG-0737[98] contains NRC's requirements for SPDS.

ITEM I.D.3: SAFETY SYSTEM STATUS MONITORING

DESCRIPTION

Historical Background

This TMI Action Plan item[48] recommended that a study be undertaken to determine the need for all licensees and applicants not committed to Regulatory Guide 1.47[150] to install a bypass and inoperable status indication system or similar system.

Safety Significance

Implementation of a well-engineered bypass and inoperable status indication system could provide the operator with timely information on the status of the plant safety systems. This operator aid could help eliminate operator errors such as those resulting from valve misalignment due to maintenance or testing errors.

Possible Solutions

A study of existing industry (nuclear and others) practices could be undertaken to evaluate possible methods/systems for verifying correct system alignment. In conjunction with this, a study of failures of systems due to pump or valve unavailability could be undertaken. Based on the results, a requirement to backfit or not backfit Regulatory Guide 1.47[150] (or a revision thereof) would be set forth.

PRIORITY DETERMINATION

Assumptions

If the system is integrated with the overall control room, then it could be expected that it would reduce operator error which, in turn, will lower the risk associated with operation of the monitored safety systems. In some plants, this "new" system could result in a modest but significant reduction in operator error during an emergency whereas, in others, the system could have no discernible effect. An average of about 2% was applied to all operating plants; plants that were not yet licensed or were undergoing licensing were committed to Regulatory Guide 1.47.[150]

In an analysis of this issue performed by PNL,[64] Oconee 3 was selected as the representative PWR. It was assumed that the fractional risk and core-melt frequency reductions for a representative BWR (Grand Gulf 1) were equivalent to those calculated for the representative PWR.

Frequency Estimate

The reduction in core-melt frequency (ΔF) for Oconee was calculated to be 8.7×10^{-7}/RY, based on adjustments to the risk equation parameters affected by implementation of the possible solution and then a calculation of a core-melt frequency and comparison to the base case core-melt frequency. Based on a scaling calculation,[64] the frequency reduction (ΔF) for Grand Gulf was 3.9×10^{-7}/RY.

Consequence Estimate

Assuming WASH-1400[16] release categories, typical midwest-site meteorology, and a uniform population density of 340 people per square-mile, the reduction in public risk was calculated to be 5.9 man-rem/RY for Oconee and 7.1 man-rem/RY for Grand Gulf. For 47 PWRs and 24 BWRs with average remaining lives of 28 years and 25 years, respectively, the total public risk reduction was calculated to be 1.2 x 10^4 man-rem.

Cost Estimate

Industry Cost: Installation costs (including labor and equipment) were estimated as follows:

	Equipment	Cost
(a)	Cable (30 miles @ $6.00/100-Lft)	$ 9,500
(b)	Electrical Penetration Limitations	300,000
(c)	Cable tray and Additional Termination	10,000
(d)	Intermediate Logic Panel	100,000
(e)	Control Room Alarms/Indications	10,000
	Total:	$429,500

	Other	Cost
(a)	Design Labor (12 man-months)	$ 75,000
(b)	Installation Labor (17 man-months)	100,000
(c)	QA	40,000
	Total:	$215,000

Based on the above costs, the implementation cost was estimated to be $644,500/plant. Maintenance of the solution was estimated to require 1 man-week/plant; at $1,000/RY, this amounted to a cost of $1.9M. Thus, the total industry cost for implementation and maintenance of the possible solution was estimated to be $48M.

NRC Cost: Development of the resolution was estimated to take 0.5 man-year. Review and implementation of the solution was estimated to take 4 man-weeks/plant. Therefore, the NRC cost was estimated to be $0.6M.

Total Cost: The total industry and NRC cost associated with the possible solution to this issue was $(48 + 0.6)M or $48.6M.

Value/Impact Assessment

Based on an estimated public risk reduction of 1.2 x 10^4 man-rem and a cost of $48.6M, the value/impact score was given by:

$$S = \frac{1.2 \times 10^4 \text{ man-rem}}{\$48.6M}$$

$$= 240 \text{ man-rem/\$M}$$

Uncertainty

Because the estimate of the value/impact score relied heavily on the estimated value of the possible reduction in human error, there may be wide variance in the effective improvement.

Additional Considerations

(1) This issue could be most effectively resolved in conjunction with Item I.D.1 which addressed control room design review. This issue was not explicitly included in the requirement for Control Room Design (Item I.D.1) which was implemented in accordance with SECY-82-111[151] and a letter[376] issued to licensees of all operating plants.

(2) Resolution of this issue was expected to provide a reduction in safety system unavailability due to the contribution of maintenance and testing.

(3) DHFS/NRR contracted with various groups to study this issue.[152,153] These studies were expected to better define the assumptions (for risk reduction) used in the calculation and provide better data for a benefit/cost study to determine implementation.

CONCLUSION

Based on the estimated public risk reduction and the value/impact score, this issue was given a medium priority ranking (See Appendix C) and RESOLVED with no new requirements.[1536] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution of the issue.

ITEM I.D.4: CONTROL ROOM DESIGN STANDARD

DESCRIPTION

Historical Background

This issue was documented in NUREG-0660[48] and emphasized a need for guidance on the design of control rooms to incorporate human factors considerations.

Safety Significance

Control rooms and control panels which incorporate human factors considerations can greatly enhance operator performance. This could contribute to a reduction in operator error and, therefore, a potential reduction in the frequency of core-melt accidents.

Possible Solution

An NRC Regulatory Guide endorsing industry standard(s) could be developed with the intention of providing: (1) guidance for the design of control rooms; and (2) the evaluation criteria for use in the licensing process.

PRIORITY DETERMINATION

Assumptions

From the representative PWR (Oconee) and BWR (Grand Gulf), those parameters in the risk equations requiring direct operator actions were considered affected, i.e., it was assumed that the probability of operator error for these parameters was decreased by 3% based on resolution of the issue.[64] It was assumed that only plants to be licensed beyond 1986 would be affected.

Frequency/Consequence Estimate

The affected accident sequences and associated base case frequencies were determined. From these frequencies, the (Affected Release Categories) base case frequencies were determined and new base case core-melt frequencies of 3.1×10^{-5} /RY and 6.1×10^{-6}/RY were calculated for PWRs and BWRs, respectively. In addition, the new base case public risk was calculated for the affected parameters. This was 79.1 man-rem/RY for PWRs and 40.4 man-rem/RY for BWRs. To determine the change in public risk from resolution of the issue, the affected parameters were adjusted by 3% and the frequencies of the associated sequences and release categories were determined. New overall core-melt frequencies were then determined: 3.01×10^{-5}/RY for PWRs and 5.95×10^{-6}/RY for BWRs. Also the new public risk was then calculated: 76.9 man-rem/RY for PWRs and 39.2 man-rem/RY for BWRs.

From the above numbers, the reduction in core-melt frequency (due to issue resolution) was calculated to be 9×10^{-7}/RY for PWRs and 1.8×10^{-7}/RY for BWRs. The public risk reduction was calculated to be 2.2 man-rem/RY for PWRs and 1.2 man-rem/RY for BWRs. Therefore, the total public risk reduction, based on 10 PWRs and 5 BWRs and an average remaining life of 30 years, was calculated to be 840 man-rem.

Cost Estimate

Industry Cost: It was assumed that, for those plants expected to be completed after 1990, the cost to implement the standard would be part of the basic cost. For those plants expected to be completed between 1987 and 1990, the cost to redesign the control room was estimated to be $100,000/plant. This was based on the assumption that, in all likelihood, draft standards were available and were used and only minor changes were needed. Also, it was assumed that the standards did not require significant equipment additions but only reworking of preliminary designs. Since there were about 10 plants to be completed between 1987 and 1990, the total industry cost for implementation was estimated to be $1M. No additional cost for yearly industry operation and maintenance was assumed.

NRC Cost: The NRC cost estimate was based on an assumed $300,000 expenditure for regulatory guide development. It was assumed that additional NRC labor of about 4 man-weeks/plant would be necessary to review the modifications that would be required for the 10 plants completed between 1987 and 1990. This totaled a cost of about $9,000/plant or $90,000 total. Thus, the total NRC cost was estimated to be $390,000.

Total Cost: The total industry and NRC cost associated with the possible solution to this issue was $(1 + 0.39)M or $1.39M.

Value/Impact Assessment

Based on an estimated public risk reduction of 840 man-rem and a cost of $1.39M, the value/impact score was given by:

$$S = \frac{840 \text{ man-rem}}{\$1.39M}$$

$$= 600 \text{ man-rem/\$M}$$

Uncertainty

The human error reduction was not easily quantifiable; 3% was used here, but it was subject to large uncertainty.

Other Considerations

(1) The issue was assumed to affect only future plants. NRC guidelines in NUREG-0700[474] were to be applied to all existing plants and NTOLs.

(2) IEEE Standards were under development at the time the issue was evaluated.

CONCLUSION

Based on the above value/impact score, this issue was given a medium priority ranking (See Appendix C) and resolved. Although no action was taken on Item I.D.4, all commercial nuclear power plants in the U.S., whether operational or under construction, were subjected to a Detailed Control Room Design Review (DCRDR) in response to TMI Item I.D.1. NUREG-0700[474] and acceptable substitutes (e.g., the Boiling Water Reactor Owners' Group "Control Room Survey Program" and "Checklist Supplement") were used as control room design standards. In accordance with 10 CFR 50.34(g), all future applications for LWRs shall include an evaluation of the proposed facility against SRP[11] Section 18.1 which addresses control room design and references NUREG-0700[474] as appropriate guidance for control room design.

Thus, staff actions negated the need for evaluation of industry control room design standards and for the development of a Regulatory Guide endorsing those standards. NUREG-0700[474] and acceptable substitutes are the de facto control room design standards for evaluating commercial nuclear power plants in the U.S. Design standards for advanced control rooms were to be addressed as a research issue under the Human Factors Research Program. Therefore, this issue was RESOLVED with no new requirements.[1101] In NUREG/CR-5382,[1563] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

ITEM I.D.5: IMPROVED CONTROL ROOM INSTRUMENTATION RESEARCH

ITEM I.D.5(1): OPERATOR-PROCESS COMMUNICATION

DESCRIPTION

Historical Background

This issue was documented in the TMI Action Plan[48] and focused on the need to evaluate the operator-machine interface in reactor control rooms. The emphasis of this portion of the overall issue was the use of lights, alarms, and annunciators.

Safety Significance

The method of presentation of information can significantly enhance the performance of the control room operators and thereby potentially affect operator error.

Possible Solution

It was proposed that existing practice and use of lights, alarms, and annunciators be reviewed to assess how well they facilitate operator-machine interaction and minimize errors. RES studied the area of control room alarms and annunciators (through a contractor) and the results were reported in NUREG/CR-2147.[244] Based on this report, RES issued RIL-124 which provided a recommendation for further action.[245]

CONCLUSION

This item was RESOLVED with no new requirements. In NUREG/CR-5382,[1563] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

ITEM I.D.5(2): PLANT STATUS AND POST-ACCIDENT MONITORING

DESCRIPTION

Historical Background

This issue was documented in the TMI Action Plan[48] and focused on the need to improve the ability of reactor operators to prevent, diagnose, and properly respond to accidents. The emphasis was on the information needs (i.e., indication of plant status) of the operator.

Safety Significance

In order for operators to perform their functions, it is necessary that they receive all the necessary information on the plant status. This can enhance operator performance (and therefore reduce operator error).

Possible Solution

Accident sequences should be analyzed to determine the information required to provide unambiguous indication of plant status. Specific instrumentation and ESF status monitoring needs would then be determined. PWR instrumentation requirements were analyzed in NUREG/CR-1440[241] and BWR instrumentation requirements were analyzed in NUREG/CR-2100.[242] ESF Status Monitoring requirements were also studied in NUREG/CR-2278.[243] RIL No. 98[246] was issued in August 1980 and transmitted "the results of completed research describing an improved method for analyzing accident sequences." Revision 2 to Regulatory Guide 1.97[55] was issued in December 1980. (See also Item II.F.3, "Instrumentation for Monitoring Accident Conditions.") The staff planned to have this guide implemented at all plants.[151,376]

CONCLUSION

This item was RESOLVED and new requirements were established.

ITEM I.D.5(3): ON-LINE REACTOR SURVEILLANCE SYSTEM

DESCRIPTION

This item was documented in the TMI Action Plan[48] based on work performed by ORNL. A continuous on-line automated surveillance system was installed at Sequoyah-1 (PWR) and information was obtained throughout the first fuel cycle. The demonstration at Sequoyah was to continue through the second fuel cycle (mid-1984). A similar demonstration at an operating BWR was planned for initiation in 1984. The system had the potential to provide diagnostic information to predict anomalous behavior of operating reactors which could be used to maintain safe conditions.

Noise surveillance and diagnostic techniques associated with the on-line reactor surveillance system have shown their safety significance and the results of the research were used by NRC in regulatory activities. Monitoring of neutron noise in BWRs was used to detect and monitor the impacting of instrument tubes against fuel boxes. The technique was used by NRC and its consultants to verify that partial power operation was safe until the next scheduled fuel outages for some 10 BWRs. Pressure noise surveillance was used at TMI-2 to monitor and guide degassification of the primary loop. The data obtained from the on-line surveillance demonstrated at Sequoyah-1 were used by NRC and its consultants in the assessment of loose thermal shields in Oconee Units 1, 2, and 3. In yet another example, NRR used results of this research in BWR stability determinations associated with regulatory actions pertaining to Dresden.

CONCLUSION

Based on the ongoing programs at the time this issue was evaluated, the technical resolution had been identified and the issue was considered nearly-resolved. As a result of the staff's work, RIL 171 was issued.[1537] Thus, the issue was RESOLVED with no new requirements.[1538] Consideration of a 20-year license renewal period would not affect the resolution.

ITEM I.D.5(4): PROCESS MONITORING INSTRUMENTATION

DESCRIPTION

This item was documented in the TMI Action Plan[48] to explore the feasibility of using new concepts for measuring certain reactor parameters. A directly related issue, Item II.F.2 in NUREG-0737,[98] mandated that industry develop and implement PWR liquid level detection systems. NRC evaluated a number of systems at the LOCA experiment facilities at ORNL and INEL.

CONCLUSION

This item was RESOLVED with no new requirements. In NUREG/CR-5382,[1563] it was concluded that consideration of a 20-year license renewal period did not affect the resolution of the issue.

ITEM I.D.5(5): DISTURBANCE ANALYSIS SYSTEMS

DESCRIPTION

Historical Background

The objective of this TMI Action Plan[48] was to explore advanced disturbance analysis systems for possible application to nuclear power plants.

Safety Significance

If potential transient events could be anticipated and terminated earlier and if operator response could be enhanced, then the core-melt frequency may be reduced. Advanced disturbance analysis systems could possibly provide the capabilities to achieve this.

Possible Solution

The purpose of this item was to assess the need, feasibility, and adequacy of advanced disturbance analysis systems. At the time that this issue was evaluated, research in this area was being conducted by EPRI.

PRIORITY DETERMINATION

Assumptions

It was assumed that the advanced disturbance analysis system would include the implementation of a continuous on-line surveillance system, as discussed in Item I.D.5(3). [A liquid level detection system was assumed available because it was already required - Items I.D.5(4) and II.F.2.]

The risk reduction was estimated by assuming a reduction in operator errors.[64] Operator error was assumed to be reduced by 2% due to the implementation of this additional operator aid. Also, a reduction in the number of transients requiring shutdown was assumed based on the potential that the operators will be able to terminate some transients before the need for shutdown. Reduced transient frequencies were calculated based on an EPRI analysis.[307] The basis for choosing

the transients was that either the detection time leading up to the transient or the time from the transient occurrence to shutdown was perceived to be longer than 30 minutes, enabling the advanced diagnostic system to diagnose the problem and provide possible solutions for the operator.

Furthermore, for purposes of this study, it was assumed that the operator could only respond with actions to 80% of the transients listed that would occur during the remaining lifetimes of the subject plants. Of the 80%, only 25% of the operators' actions was assumed to prevent the need for shutdown. The average plant shutdown was assumed to last 0.75 day. Therefore, reduction in unscheduled outages was calculated as follows:

PWR: (4.63 transients/RY)(0.80)(0.25)(0.75 day/shutdown) = 0.69 day/RY

BWR: (5.20 transients/RY)(0.80)(0.25)(0.75 day/shutdown) = 0.78 day/RY

Frequency Estimate

The parameters which included direct operator action were adjusted based on the 2% operator error reduction. In addition, the reduced transient frequency calculated from above were divided by the total PWR and BWR transient frequencies (i.e., 9.8 events/RY for PWRs and 8.9 events/RY for BWRs) to give a percent transient reduction. Then the parameters for transients (T_2 and T_3 for PWRs and T_{23} for BWRs) were adjusted.

Combining the reduction in operator error and the reduction in transient frequencies, the reductions in core-melt frequencies were 4.4×10^{-6} event/RY for PWRs and 2.6×10^{-6} event/RY for BWRs.

Consequence Estimate

The associated reduction in public risk was calculated (assuming 340 people per square mile) to be 12 man-rem/RY for PWRs and 18 man-rem/RY for BWRs. Assuming 90 PWRs and 44 BWRs with remaining lives of 28.8 and 27.4 years, respectively, the total public risk reduction was calculated to be 53,000 man-rem.

Cost Estimate

Industry Cost: For the advanced diagnostic system, implementation costs (hardware and installation) were estimated to be $1.5M/plant. The on-line surveillance system was estimated to cost $125,000/plant for hardware and $375,000/plant for installation. For 134 plants, the total implementation cost was approximately $270M.

Operation and maintenance was estimated to be about 10 man-weeks/RY beyond that required for control room instrumentation. Therefore, this cost would be (10 man-weeks/RY)($2,270/man-week)(134 plants)(30 years) or $91M. Therefore, the total industry cost was estimated to be $360M.

NRC Cost: NRC costs for resolution were considered to be relatively minor ($2M), based on the assumption that EPRI would continue to do the major portion of the research on the issue. Labor to approve and monitor hardware changes for the backfit of the affected plants was based on an average of 4 man-weeks/plant. The

total cost for this effort was given by (4 man-weeks/backfit plant)($2,270/man-week)(71 plants) or $650,000. Therefore, the total NRC cost was $2.65M.

Total Cost: The total industry and NRC cost associated with the possible solution to this issue was $(360 + 2.65)M or $362.65M.

Value/Impact Assessment

Based on an estimated public risk reduction of 53,000 man-rem and a cost of $362.65M, the value/impact score was given by:

$$S = \frac{53{,}000 \text{ man-rem}}{\$362.65M}$$

$$= 150 \text{ man-rem/\$M}$$

Uncertainty

The assumed benefits of resolution and cost for implementation were extremely hard to quantify because of the uncertain nature of possible future developments in this area.

Other Considerations

(1) If it were assumed that replacement power costs were $300,000/day and, as previously calculated, resolution would reduce down time by 0.69 day/RY for PWRs and 0.78 day/RY for BWRs, the industry cost saving would be:

($300,000/day)[(0.69 day/RY)(90 plants)(30 years) +
(0.78 day/RY)(44 plants)(30 years)] = $870M

Combining this with the industry costs (implementation and operation) would show an industry saving of about $500M. Including accident avoidance costs would further increase this saving.

(2) EPRI was conducting research in this area which was being followed by NRC.

CONCLUSION

Based on the judgment that a disturbance analysis system could reduce operator errors by 2% and the number of transients by a factor of 2, the issue was assigned a medium priority ranking (See Appendix C). After a more detailed review, the staff concluded that, although disturbance analysis systems might decrease plant shutdowns and thereby reduce plant costs, this economic benefit should not be a reason for requiring installations of such systems because the assumed safety benefit was too uncertain. The staff further concluded that, in order to determine whether or not a specific safety problem existed, more research was necessary to determine the effect that disturbance analysis systems could have on operator performance.[1099] As a result, the issue was reclassified as a Licensing Issue and integrated into the research activity, Human Factors Aspects of Advanced Controls and Instrumentation.[1100]

Guidelines for the verification and validation of expert systems that could be used in the development and review of disturbance analysis systems were developed

from a joint EPRI/NRC research program; these were published in NUREG/CR-6316.[347] Thus, this Licensing Issue was resolved.[271]

ITEM I.D.6: TECHNOLOGY TRANSFER CONFERENCE

DESCRIPTION

In January 1980, the NRC and IEEE jointly sponsored a technology transfer conference entitled "Advanced Electrotechnology Applications to Nuclear Power Plants" which had as its objective consideration of the practicality of applying advanced technologies from other industries (e.g. aerospace, defense, aviation) to the nuclear power industry.

During the conference, eight parallel workshops were held including: Systems Management Techniques; Reliability Engineering; Risk Assessment; Software Reliability Verification and Validation; Smart Instrumentation; Operational Aids-Command Control and Communications; Education, Training, and Simulators; and Simulation and Analysis. The conference report[306] was issued in June 1980. This item was related to increasing knowledge and understanding of safety issues and, therefore, was considered a Licensing Issue.

CONCLUSION

This Licensing Issue was resolved with the completion of the conference.

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242. NUREG/CR-2100, "Boiling Water Reactor Status Monitoring During Accident Conditions," U.S. Nuclear Regulatory Commission, May 1981.

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306. IEEE Catalog No. TH0073-7, "Record of the Working Conference on Advanced Electrotechnology Applications to Nuclear Power Plants, January 15-17, 1980, Washington, D.C." Institute of Electrical and Electronics Engineers.

307. EPRI NP-2230, "ATWS: A Reappraisal, Part 3," Electric Power Research Institute, 1982.

347. NUREG/CR-6316, "Guidelines for the Verification and Validation of Expert System Software and Conventional Software," U.S. Nuclear Regulatory Commission, (Vol. 1) March 1995, (Vol. 2) March 1995, (Vol. 3) March 1995, (Vol. 4) March 1995, (Vol. 5) March 1995, (Vol. 6) March 1995, (Vol. 7) March 1995, (Vol. 8) March 1995.

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

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1099. Memorandum for B. Morris from B. Sheron, "Updated GIMCS for GI I.D.5(5)," February 2, 1988.

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1563. NUREG/CR-5382, "Screening of Generic Safety Issues for License Renewal Considerations," U.S. Nuclear Regulatory Commission, December 1991.

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TASK I.E: ANALYSIS AND DISSEMINATION OF OPERATING EXPERIENCE

The objective of this task was to establish an integrated program which involved participation by the licensees, vendors, NSAC, INPO, and the NRC, and which included foreign operations experience for the systematic collection, review, analysis, and feedback of operating experience to NRC licensing, inspection, standards, and research activities, and to licensees for all NRC-licensed activities. Appropriate corrective action was expected to be taken in response to feedback.

ITEM I.E.1: OFFICE FOR ANALYSIS AND EVALUATION OF OPERATIONAL DATA

DESCRIPTION

The purpose of this TMI Action Plan[48] item was to establish an NRC office which would be responsible for: (1) analysis and evaluation of operational data associated with all NRC-licensed activities; and (2) development of specific recommendations for action by other NRC offices.

Systematic evaluation of operating data can identify potential significant safety problems or their precursors. Dissemination to NRC and industry of evaluation results which identify such problems, along with recommendations for their resolutions, can avoid occurrence of these problems at other plants of similar design. This item was initiated to improve the NRC capability to make independent assessments of safety and, therefore, was considered a Licensing Issue.

CONCLUSION

The Commission approved the establishment of AEOD in July 1979 and an interim office was established in October 1979. As of June 1984, AEOD was staffed and functioning in accordance with the purpose and scope described in Chapter 0143 of the NRC Manual. Thus, this Licensing Issue was resolved.

ITEM I.E.2: PROGRAM OFFICE OPERATIONAL DATA EVALUATION

DESCRIPTION

The purpose of this TMI Action Plan[48] item was to ensure that each NRC office conducted operational safety analyses. These analyses were to be coordinated and the results distributed as part of the integrated program on operating experience assessments. The work of each office was expected to complement the operational data evaluation activities conducted by AEOD under Item I.E.1.

Systematic evaluation of operational data can identify potential significant safety problems or their precursors. Dissemination to NRC offices and industry of such evaluations, along with their resolution, can avoid occurrence of these problems at other facilities of similar design that conduct similar operations. This item was initiated to improve the NRC capability to make independent assessments of safety and, therefore, was considered a Licensing Issue.

CONCLUSION

As of June 1984, each of the following NRC Offices had established responsibility and procedures for evaluating operational data:

(1) In OIE, the Events Analysis Branch had the lead responsibility for this activity using input from such sources as LERs, Preliminary Notices, 10 CFR 21 Reports, 10 CFR 50.55(e) Construction Deficiency Reports, and 10 CFR 50.72 Reports to the NRC Operations Center. Evaluations which identified potential significant safety problems were disseminated by means such as IE Notices or IE Bulletins.

(2) In NRR, the Operating Reactors Assessment Branch (ORAB) conferred daily with OIE on operational occurrences and made preliminary assessments of their safety significance as part of their functional responsibility described in the NRC Manual. Those occurrences which were considered to have potential safety significance were identified at weekly NRR management briefings on operational events conducted by ORAB with OIE participation. If deemed necessary, further evaluation was assigned to the appropriate NRR Division.

(3) In RES, the Reactor Risk Branch had lead responsibility for evaluating operational events and was responsible for issuance of periodic reports on Precursors to Potential Severe Core Damage Accidents,[76] which were derived from a systematic review of LERs. These reports provided operational experience data and were available for use in Event Tree Analyses and PRAs conducted by RES.

(4) NMSS had issued a procedure[305] for achieving a more formal review and evaluation of inspection and operational data and event reports to identify and correct generic problems. The procedure included criteria for identifying operational events that warranted detailed review and evaluation. Evaluation reports that identified safety significant operational events were distributed within NRC.

Based on the actions taken by the cognizant Offices, this Licensing Issue was resolved.

ITEM I.E.3: OPERATIONAL SAFETY DATA ANALYSIS

DESCRIPTION

The purpose of this TMI Action Plan[48] item was to conduct special operational safety data analyses to determine equipment failure rates and to develop error data analysis for nuclear plant operations. As of June 1984, the Reactor Risk Branch of RES was performing studies to: (1) determine equipment failure rates using LERs; (2) develop and use common-cause/common-mode analysis of LERs; (3) analyze data from the NPRDS to distinguish order-of-magnitude differences in component failure rates between such factors as plants, sizes, service environment, status at time of failure, and manufacturer; (4) identify potential reliability problems evident in the LER data; and (5) identify potential accident precursors.

The information obtained from this item was used to: (1) provide more reliable equipment failure rate data, including common-cause/common-mode failure statistics to support PRAs of nuclear power plants (see Items II.C.1, "Interim Reliability Evaluation Program," and II.C.2, "Continuation of IREP"); and (2) to identify potentially serious equipment reliability problems evident from LER data and provide feedback to equipment maintenance/surveillance programs to reduce equipment failure rates (see Item II.C.4, "Reliability Engineering"). This item was initiated to improve the NRC capability to assess safety and, therefore, was considered a Licensing Issue.

CONCLUSION

At the time of this evaluation, implementation of the program had resulted in the following:

(1) Publication of data summaries of LERs on pumps, control rods and drive mechanisms, diesel generators, valves, primary containment penetrations, and instrumentation and control components (See References 344, 345, 346, 348, 349, 350, and 351).

(2) Equipment unavailability data from nuclear plant log books obtained as part of the In-Plant Reliability Data System (IPRDS).[353,354]

(3) Publication of reports on common-cause/common-mode failures (See References 355, 356, 357, 358, 359, 360, and 361).

(4) Preparation of a computer program (FRANTIC) for use in upgrading equipment maintenance/surveillance programs (See References 124, 138, 362, and 363).

This item was an ongoing effort to collect and analyze data. While no quantified safety benefits could be directly assigned to it, the benefits occurred as the results of the equipment failure rate data and reliability analysis were used in assessing other specific related safety issues, including Items II.C.1, II.C.2, and II.C.4. The ongoing activities were to be conducted as described in Section 16.1 of the NRC Long Range Research Program.[133] Thus, this Licensing Issue was resolved.

ITEM I.E.4: COORDINATION OF LICENSEE, INDUSTRY, AND REGULATORY PROGRAMS

DESCRIPTION

The purpose of this TMI Action Plan[48] item was to ensure coordination of licensee, industry, and NRC programs for evaluating plant operating experience. As part of the implementation of NUREG-0737,[98] licensees established the capability for evaluating plant operating experience and procedures for providing feedback of the information to operations personnel and for incorporating it into training programs, in accordance with Items I.A.1.1, I.B.1.2, and I.C.5. Industry evaluation programs were to be conducted by INPO. AEOD was responsible for coordinating the NRC programs for evaluation of operational data with those of licensees and industry.

Licensee evaluations of plant operating experience, coordinated with industry and NRC evaluations using common data bases, were to ensure that licensee, industry,

and NRC corrective action recommendations were properly coordinated and applied. Effective feedback of prioritized and analyzed event descriptions to plant operating personnel and incorporation into training programs can avoid occurrence of these problems at other plants of similar design. This item was initiated to improve the NRC capability to assess safety and, therefore, was considered a Licensing Issue.

CONCLUSION

The results of industry and NRC operating experience evaluations are shared under an NRC-INPO Memorandum of Agreement[238] initially signed in June 1981 and revised in April 1982. Thus, this Licensing Issue was resolved.

ITEM I.E.5: NUCLEAR PLANT RELIABILITY DATA SYSTEM

This item was evaluated with Item I.E.6 below and resolved.

ITEM I.E.6: REPORTING REQUIREMENTS

Items I.E.5 and I.E.6 were combined and evaluated together.

DESCRIPTION

The objectives of these TMI Action Plan[48] items were to: (1) determine if there was a need to make licensee participation in NPRDS mandatory; and (2) establish improved reporting requirements for operating reactors.

NPRDS is a reliability-oriented data collection and reporting system for selected components and systems related to the safety of nuclear power plants. Periodic reports containing failure statistics are issued and licensee participation is voluntary. Improvements in reporting significant events of operating plants can identify potential significant safety problems or their precursors and can avoid occurrence of these problems at other plants of similar design. Improved reporting of system/component reliability data will increase the validity of operating experience assessments and PRA programs. This item was initiated to improve the NRC capability to assess safety and, therefore, was considered a Licensing Issue.

CONCLUSION

By affirmation of SECY-81-494,[260] the Commission endorsed the following staff actions to resolve these issues: (1) develop a proposed rule to modify and codify the existing LER requirements and to assure consistency with 10 CFR 50.72 which covers the immediate reporting of significant events; (2) endorse the INPO plan to assume responsibility for the management, funding, and technical direction of NPRDS; (3) coordinate with INPO to minimize duplication between the LER and NPRDS systems and between subsequent NRC and INPO analysis of NPRDS data; (4) obtain INPO assurance that NPRDS receives, processes, and disseminates the reliability data needed by industry and the NRC to support PRA programs; and (5) monitor (by AEOD) INPO's management of the NPRDS and provide the Commission with semi-annual reports on the effectiveness of INPO management of NPRDS.

As of January 1982, INPO had assumed responsibility for the NPRDS and the NRC was represented on the NPRDS Users' Group and participated in various NPRDS work groups. AEOD submits semi-annual reports to the Commission on the effectiveness of the INPO management of NPRDS. A proposed rule on LERs was published in the Federal Register (47 FR 19543) on May 6, 1982, and the final rule[597] was published in July 1983. Based on the actions described above, Items I.E.5 and I.E.6 are Licensing Issues that were resolved.

ITEM I.E.7: FOREIGN SOURCES

DESCRIPTION

The purpose of this TMI Action Plan[48] item was to supplement domestic operating experience of safety significance by obtaining operating and design information from foreign reactors. To obtain foreign experience in a more systematic manner, the Office of International Programs (IP) participated with nuclear regulatory agencies of other nations in a centralized exchange of incident information with the Nuclear Energy Agency (NEA); this NEA exchange was initiated in 1980. Supplementing this effort was the upgrading of information exchange on significant incidents through direct contact and correspondence between the NRC and its bilateral partners, and by additional formal bilateral information exchange agreements which were concluded or renewed in 1981 and 1982.

AEOD also sponsors a program by which the Nuclear Operations Analysis Center at ORNL screens and stores for ready access reports of foreign reactor incidents and provides monthly summaries of these events that are potentially significant and relevant to U.S. LWRs. This item was initiated to improve the NRC capability to assess safety and, therefore, was considered a Licensing Issue.

CONCLUSION

As of June 1984, foreign reactor incident and operating experience reports were being routinely received and disseminated to NRC technical staffs. IP was also routinely sending these foreign reactor incident reports to INPO for use by industry in evaluating plant operating experience under Item I.E.4. Foreign reactor incident and operating experience reports were being assessed by AEOD and affected NRC Offices, as described in Items I.E.1 and I.E.2, respectively, to identify potential significant safety problems or their procedures which may be applicable to U.S. plants. Dissemination within NRC and to industry of such assessments, along with their resolutions, can avoid occurrence of these problems at other facilities of similar design. Thus, this Licensing Issue was resolved.

ITEM I.E.8: HUMAN ERROR RATE ANALYSIS

DESCRIPTION

The TMI-2 incident increased concern for the effect of human reliability on reactor safety. The lack of human reliability data applicable to nuclear power plants compared to hardware reliability data highlighted this concern in nuclear safety assessments and regulation. The purpose of this TMI Action Plan[48] item was to continue research to: (1) complete analysis of field-collected data for human reliability in maintenance and calibration activities at operating nuclear power

plants; (2) review abnormal occurrence reports, licensee event reports, and compliance reports to identify areas where human performance reliability is low; (3) develop probability models to predict error rates for multiple human errors occurring as a function of coupling influences; and (4) identify patterns and basic associative factors for the human-error rates determined for basic test, maintenance, and operator actions.

The information obtained from this item was to be used to: (1) identify necessary improvements in operator training and training aids to reduce human error rates (see Items I.A.2.6, "Long-Term Upgrading of Training and Qualification of Operating Personnel," and I.A.4.2, "Long-Term Training Simulator Upgrade"); and (2) provide quantifiable human error data and models to support PRA of nuclear power plants [see Items II.C.1, "Interim Reliability Evaluation Program" (IREP), and II.C.3, "Continuation of IREP"]; and (3) provide human engineering criteria for evaluating the design of new or modified systems.

While no quantified safety benefit could be directly assigned to this item, the benefits were expected to occur as the results of the human error rate and reliability analyses were used in assessing other individual related safety issues, including TMI Action Plan Items I.A.2.6, I.A.4.2, II.C.1, II.C.2, and Task Action Plan Item B-17. Therefore, this item was considered a Licensing Issue.

CONCLUSION

The Human Factors Branch of RES implemented an expanded Human Reliability research program to accomplish the purpose of this item and provide the human error information for its end use as described above. Major reports issued included: (1) a human reliability data bank[338]; (2) a draft handbook for human reliability analysis[339]; (3) procedures for estimating human error probabilities[341,342]; and (4) a workbook for conducting human reliability analysis.[343] Future work included finalizing the handbooks, workbooks, and reliability models and maintaining the data bank; this work was described in Section 7.1 of the NRC Long Range Research Plan.[133] Thus, this Licensing Issue was resolved.

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339. NUREG/CR-1278, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," U.S. Nuclear Regulatory Commission, October 1983.

341. NUREG/CR-2255, "Expert Estimation of Human Error Probabilities in Nuclear Power Plant Operations: A Review of Probability Assessment and Scaling," U.S. Nuclear Regulatory Commission, May 1982.

342. NUREG/CR-2743, "Procedures for Using Expert Judgment to Estimate Human Error Probabilities in Nuclear Power Plant Operations," U.S. Nuclear Regulatory Commission, February 1983.

343. NUREG/CR-2254, "Workbook for Conducting Human Reliability Analysis," U.S. Nuclear Regulatory Commission, February 1983.

344. NUREG/CR-1205, "Data Summaries of Licensee Event Reports of Pumps at U.S. Commercial Nuclear Power Plants," U.S. Nuclear Regulatory Commission, January 1980, (Rev. 1) January 1982.

346. NUREG/CR-1363, "Data Summaries of Licensee Event Reports of Valves at U.S. Commercial Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1980, (Rev. 1) October 1982.

348. NUREG/CR-1362, "Data Summaries of Licensee Event Reports of Diesel Generators at U.S. Commercial Nuclear Power Plants, January 1, 1976 through December 31, 1978," U.S. Nuclear Regulatory Commission, March 1980.

349. NUREG/CR-1331, "Data Summaries of Licensee Event Reports of Control Rods and Drive Mechanisms at U.S. Commercial Nuclear Power Plants, January 1, 1972 through April 30, 1978," U.S. Nuclear Regulatory Commission, February 1980.

350. NUREG/CR-1730, "Data Summaries of Licensee Event Reports of Primary Containment Penetrations at U.S. Commercial Nuclear Power Plants, January 1, 1972 through December 31, 1978," U.S. Nuclear Regulatory Commission, September 1980.

351. NUREG/CR-1740, "Data Summaries of Licensee Event Reports of Selected Instrumentation and Control Components at U.S. Commercial Nuclear Power Plants from January 1, 1976 to December 31, 1978," U.S. Nuclear Regulatory Commission, May 1981.

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360. EGG-EA-5289, "Common Cause Fault Rates for Pumps: Estimates Based on Licensee Event Reports at U.S. Commercial Nuclear Power Plants, January 1, 1972 through September 30, 1980," EG&G, Inc., (Rev. 1) August 1982.

361. JBFA-101-82, "Common Cause Screening Methodology Project (FY 81 Technical Progress Report)," JBF Associates, Inc., February 1982.

362. NUREG/CR-2542, "Sensitivity Study Using the FRANTIC II Code for the Unavailability of a System to the Failure Characteristics of the Components and the Operating Conditions," U.S. Nuclear Regulatory Commission, February 1982.

363. NUREG/CR-2332, "Time Dependent Unavailability of a Continuously Monitored Component," U.S. Nuclear Regulatory Commission, August 1981.

597. Federal Register Notice, 48 FR 33850, "Licensee Event Report System," July 26, 1983.

TASK II.H: TMI-2 CLEANUP AND EXAMINATION

The objectives of this task were to: (1) maintain safety and minimize environmental impact of post-accident operation and cleanup of TMI-2; and (2) obtain and factor into regulatory programs safety-related and environmental information from the TMI-2 cleanup.

ITEM II.H.1: MAINTAIN SAFETY OF TMI-2 AND MINIMIZE ENVIRONMENTAL IMPACT

DESCRIPTION

This TMI Action Plan[48] item covered the efforts by NRC to monitor, review, and assess the safety and environmental impact of the post-accident operation, cleanup, and possible recovery operations at TMI-2 to ensure that: (1) reactor safety and reactor building integrity was maintained; (2) environmental impacts were minimized and radiation exposure to workers, the public, and the environment was within regulatory limits and was as low as reasonably achievable (ALARA); and (3) storage and/or disposal of radioactive wastes from cleanup operations were safe. The TMI Program Office (TMIPO) within NRR directed the NRC activities under this task.

NUREG-0698,[198] Rev. 1, was issued in February 1982 and provided an updated chronology of TMI-2 cleanup activity, major milestones, and accomplishments summarized as follows:

(1) In March 1981, the NRC issued NUREG-0683,[199] a Final Programmatic Environmental Impact Statement (PEIS) related to the decontamination and disposal of radioactive wastes resulting from the accident.

(2) In conjunction with the issuance of the PEIS, the NRC also issued a Policy Statement[211] in April 1981 which stated that the cleanup should be expedited consistent with maintaining public health and safety.

(3) In July 1981, a Memorandum of Understanding (Appendix A to NUREG-0698[198]) concerning the removal and disposition of radioactive solid wastes from the cleanup operations was signed by representatives of NRC and the Department of Energy.

(4) Cleanup operations were implemented according to the plan. Decontamination of accident-generated water in the auxiliary and fuel handling buildings was completed by mid-1981. Decontamination of accident water located in the reactor building sump and reactor coolant system was initiated in September 1981. Visual examination of the top of the damaged reactor core was performed with the use of a remote miniature TV introduced through control rod drive housing.

This issue was identified in NUREG-0885[210] as one of NRC's highest safety priorities.

CONCLUSION

The cleanup operation was implemented[377] and the issue was programmatically RESOLVED with appropriate management resources and priorities assigned; no new requirements were established. In NUREG/CR-5382,[1563] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

ITEM II.H.2: OBTAIN TECHNICAL DATA ON THE CONDITIONS INSIDE THE TMI-2 CONTAINMENT STRUCTURE

DESCRIPTION

Pertinent technical information was to be obtained on the conditions of the TMI-2 facility as cleanup operations proceeded. The information to be gathered and disseminated (Item II.H.3) was divided into two distinct categories: (1) data to be obtained prior to gaining access to the primary system; and (2) data to be obtained after access to the primary system. In the first category, information was to be obtained on: (1) instrumentation and electrical equipment survivability under the accident conditions; (2) environmental conditions in the containment and auxiliary buildings; (3) fission-product release, transport, and deposition; (4) decontamination, dose reduction, and waste handling; and (5) debris in the containment building, in particular the containment sump.

After access to the primary system was obtained, the primary system pressure boundary was to be characterized including the steam generators, pumps, and other mechanical and structural components. Techniques were to be developed for a non-destructive assay of fuel distribution in the primary system for assessing criticality control during examination and cleanup operations and for fuel removal, packaging, shipment, and disposal. Detailed pre-access reactor and core damage assessments were to be made followed by careful in situ and away-from-site fuel and reactor internals examinations.

The societal risk from the operation of nuclear power plants would not be reduced by just obtaining, preserving, and disseminating information as outlined above. However, the potential for risk reduction due to proper use of increased knowledge obtained by studying the TMI-2 facility cannot be denied. The information that could be obtained through this item was to be used in the pursuance of other safety issues such as:

A-45	Shutdown Decay Heat Removal Requirements
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment
II.B.5	Research on Phenomena Associated with Core Degradation on Fuel Melting
II.B.7	Analysis of Hydrogen Control
II.B.8	Rulemaking Proceedings on Degraded Core Accidents
II.E.3.4	Alternate Decay Heat Removal Concepts

Insights gained from the above TMI-2 information were assumed in a qualitative sense in the development of the potential risk reduction for the 6 issues outlined above. The total risk reduction estimated for the resolution of these 6 issues was 610,000 man-rem of public exposure and 650,000 man-rem of

occupational exposure; to include further potential risk reduction under Item II.H.2 (and II.H.3) would result in double-counting.

At the time this issue was evaluated, it was assumed that the TMI-2 cleanup was about 40% complete, about 60% of the $1.2 Billion licensee estimated cost remained to be expended, and about 10% of the licensee's costs was consumed in the preservation and recording of technical data. It was estimated that there was $72M of licensee funding yet to be expended on this effort. Using the TMI Action Plan[48] cost and manpower estimates and extrapolating through FY-1985, it was determined that the NRC cost would be about $36M, of which, about 60% or $22M had not yet been expended. It was also assumed that a DOE commitment of approximately $22M had yet to be expended. This resulted in a total future cost of about $116M for the completion of Items II.H.2 and II.H.3.

Table II.H.2-1 shows the estimated risk reduction, cost, and recommended priority for each of the above 6 issues. The total future costs estimated for all 6 issues was approximately $2 Billion. The total future cost for completion of Items II.H.2 and II.H.3, although large ($116M), was a reasonably small portion (~6%) of total future costs expected for the resolution of those safety issues that will utilize information obtained from the TMI-2 facility. If the cost associated with these items was compared only with the estimated total cost for resolving Issues A-45 and A-48, the cost of the TMI information retrieval program would represent only about 15% of the cost of these two issues. Compared to Items II.B.5 and II.B.8, the cost of the TMI information retrieval program represented less than 10% of the estimated cost for the completion and implementation of Items II.H.2 and II.H.3.

Table II.H.2-1

Issue	Recommended Priority	Risk Reduction (Man-Rem)	Total Cost ($M)
A-45*	High	4.7×10^5	500
A-48*	High	5.2×10^5	208
II.B.5	High	2.2×10^5	1,300
II.B.7	(Subsumed in A-48)	-	-
II.B.8	(Subsumed in II.B.5)	-	-
II.E.3.4	(Subsumed in A-45)		
	TOTAL:	1.2×10^6	2,008

* Unreleased Draft Analyses

CONCLUSION

This issue addressed the collection (Item II.H.2) and dissemination (Item II.H.3) of information that was to be used in the completion of other specific safety issues and thus was not analyzed separately. However, examination of the recommended priority for those issues that depended in part on input from the TMI information to be obtained via this issue indicated that this issue supported other high priority issues. Thus, this issue was given a high priority (See Appendix C).

Core examinations indicated that a large flow of molten material (about 19 metric tons) relocated into the lower plenum after the accident had been in progress for about 225 minutes. All vessel steel, nozzle, and guide tube samples extracted from TMI-2 were tested and analyses of the potential reactor vessel failure modes were conducted. The staff's findings were forwarded to the Commission in SECY-93-119.[1539] Thus, this issue was RESOLVED with no new requirements.[1540] Consideration of a 20-year license renewal period would not affect this resolution.

ITEM II.H 3: EVALUATE AND FEEDBACK INFORMATION OBTAINED FROM TMI-2

DESCRIPTION

This TMI Action Plan[48] item involved the analysis of data obtained during the examination of systems inside the containment building at TMI-2, the subsequent decontamination and restoration of the facility, and the feedback of the information obtained into other appropriate regulatory programs. Item II.H.2 was devoted to the efforts necessary to acquire and record information during the cleanup of the TMI-2 facility.

CONCLUSION

Since the acquisition of the TMI-2 data had to be accomplished before the data could be evaluated, no changes in requirements could be ascertained until those data were evaluated. Therefore, Items II.H.2 and II.H.3 were inextricable and were combined and evaluated together under Item II.H.2.

ITEM II.H.4: DETERMINE IMPACT OF TMI ON SOCIOECONOMIC AND REAL PROPERTY VALUES

DESCRIPTION

Studies were to be conducted on: (1) the effect of the TMI accident on the value of real property in the Harrisburg, Pennsylvania, area; and (2) the socioeconomic impact of the TMI accident on the region in south-central Pennsylvania which surrounds TMI. This item was initiated to increase the NRC knowledge in assessing levels of safety and, therefore, was considered a Licensing Issue.

CONCLUSION

A Pennsylvania State University study[313] of the effects of the accident on property values in the vicinity of the TMI-2 site was accepted by the staff and published in March 1981. A study of the socioeconomic effects of the accident in the region surrounding the plants was performed by Mountain West Research Incorporated. This report[314] was accepted by the staff and published in July 1982. Thus, this Licensing Issue was resolved.

REFERENCES

48. NUREG-0660, "NRC Action Plan Developed as a Result of the TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Rev. 1) August 1980.

198. NUREG-0698, "NRC Plans for Cleanup Operations at Three Mile Island Unit 2," U.S. Nuclear Regulatory Commission, July 1980.

199. NUREG-0683, "Final Programmatic Environmental Impact Statement Related to Decontamination and Disposal of Radioactive Wastes Resulting from the March 28, 1979 Accident at Three Mile Island Nuclear Station, Unit 2," U.S. Nuclear Regulatory Commission, March 1981.

210. NUREG-0885, "U.S. Nuclear Regulatory Commission Policy and Planning Guidance," U.S. Nuclear Regulatory Comnmission, (Issue 1) January 1982, (Issue 2) January 1983, (Issue 3) January 1984, (Issue 4) February 1985, (Issue 5) February 1986, (Issue 6) September 1987.

211. Federal Register Notice 46 FR 764, "NRC Policy Statement on Cleanup of the Three Mile Island Plant," May 1, 1981.

313. NUREG/CR-2063, "Effects of the Accident of Three Mile Island on Property Values and Sales," U.S. Nuclear Regulatory Commission, March 1981.

314. NUREG/CR-2749, "Socioeconomic Impacts of Nuclear Generating Stations - Three Mile Island Case Study," U.S. Nuclear Regulatory Commission, (Vol. 12) July 1982.

377. Memorandum for W. Minners from B. Snyder, "Schedule for Resolving and Completing Generic Issues," December 16, 1982.

1539. SECY-93-119, "TMI-2 Vessel Investigation Project," May 5, 1993.

1540. Memorandum for J. Taylor from E. Beckjord, "Closure of Generic Issue II.H.2, 'Obtain Data on Conditions Inside TMI-2 Containment,'" February 9, 1994.

1563. NUREG/CR-5382, "Screening of Generic Safety Issues for License Renewal Considerations," U.S. Nuclear Regulatory Commission, December 1991.

TASK II.J.4: REVISE DEFICIENCY REPORTING REQUIREMENTS

The objective of this task was to clarify deficiency report requirements to obtain uniform reporting and earlier identification and correction of problems.

ITEM II.J.4.1: REVISE DEFICIENCY REPORTING REQUIREMENTS

DESCRIPTION

This TMI Action Plan[48] item called for the NRC to revise, as necessary, the event-reporting requirements of 10 CFR 21 to assure that all reportable items are reported promptly and that the information submitted is complete. Improvements were to be implemented by rule changes, as appropriate, and coordinated with those made under TMI Action Plan Item I.E.6. The reports received as a result of these rule changes were to provide increased information on component failures that affect safety so that prompt and effective corrective action could be taken. The information was also to be used as input to an augmented role of the NRC's vendor and construction inspection program.

CONCLUSION

This issue was originally classified as nearly-resolved based on changes to 10 CFR 21 and 10 CFR 50.55(e) proposed by OIE[291,292] and was later RESOLVED with new requirements when amendments to 10 CFR 21 and 10 CFR 50.55(e) were issued.[1396] The staff's changes were presented to the Commission in SECY-91-150.[1397] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

REFERENCES

48. NUREG-0660, "NRC Action Plan Developed as a Result of tlle TMI-2 Accident," U.S. Nuclear Regulatory Commission, May 1980, (Rev. 1) August 1980.

291. Memorandum for E. Jordan, et al., from R. Bernero, "Proposed Rule Review Request - 10 CFR Part 21 and 10 CFR Part 50.55(e), Reporting of Defects and Non-Compliance," February 3, 1983.

292. Memorandum for R. Minogue from R. DeYoung, "Proposed Rule Amending 10 CFR Parts 50.55(e) and 21: RES Task Numbers RA 128-1 and RA 808-1," July 13, 1982.

1396. Federal Register Notice 56 FR 36081, "10 CFR Parts 21 and 50, Criteria and Procedures for the Reporting of Defects and Conditions of Construction Permits," July 31, 1991.

1397. SECY-91-150, "Proposed Amendments to 10 CFR Part 21, 'Reporting of Defects and Noncompliance' and 10 CFR 50.55(e), 'Conditions of Construction Permits,'" May 22, 1991.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ITEM B-22: LWR FUEL

DESCRIPTION

Historical Background

Individual reactor fuel rods sometimes fail during normal operations and many fuel rods are expected to fail during severe accidents. To ensure that these fuel failures do not result in unacceptable releases to the public, regulations have been promulgated that require a coolable, rod-like geometry to be maintained. The behavior of fuel under normal and accident conditions must be predicted to ensure that the regulatory requirements are met. Because many factors impact the behavior of the fuel under both normal and accident conditions, e.g., fuel rod bowing, densification, cladding fragmentation, etc., this issue was identified in NUREG-0471[3] to determine whether such predictions were reliable.

Safety Significance

Failure of fuel rods results in a radioactive release within a plant and is a potential source of release to the public. To remain within the regulatory requirements for acceptable release rates, a plant may be required to shut down or operate at a reduced power level. The behavior of reactor fuel must be predictable and these predictions must be reliable to ensure that: (1) operating limits are not exceeded; (2) activity releases are limited; and (3) the fuel system does not degrade by an unacceptable amount.

Possible Solution

A possible solution to this issue involved developing methods to reduce fuel failures and to limit activity releases. These methods can work if fuel behavior can be predicted for normal operations and postulated accident conditions and if operating limits are set in accordance with these predictions.

In an attempt to control fuel failures, some design changes in fuel assemblies were made by GE. However, it was believed that most of the efforts to resolve this issue would be in trying to predict or alter power excursions and reduce releases by controlling such events as steam generator leakages. Although controlling power excursions may not be feasible under accident conditions, it is feasible during planned power maneuvers when the potential for fuel failures may be limited.

PRIORITY DETERMINATION

Frequency Estimate

Accident frequency is principally a function of equipment reliability and the frequency of accident initiators. Neither of these factors is influenced by the presence of failed fuel. Thus, the influence of failed fuel on accident frequency is extremely small.

Consequence Estimate

Fuel defects increase releases during normal operation and transients, but these increases would remain within 10 CFR 20 limits. The magnitude of a release from failed fuel during an accident is much larger than the release from a pre-existing fuel defect, and the release during a severe accident is not expected to be significantly affected by pre-existing fuel defects. Thus, the resultant consequence from failed fuel was determined to be very small.[64]

Cost Estimate

Industry Cost: The cost to implement the possible solution would be primarily for training. It was assumed that some minor fuel assembly design changes would be made and that power excursions would be altered during planning power maneuvers. Implementing these changes would only require training the appropriate operations staff.

Training personnel for minor fuel assembly design changes would require a minimal amount of staff labor. It was estimated that 2 man-weeks would be required to train all personnel handling fuel assemblies or supervising refueling techniques. Changes in operations reflected by alterations in power excursions would require that all reactor operators and supervisors receive appropriate training. Five shifts/plant were assumed to be available with one of these being the training shift. It was assumed that the following personnel would receive 10 man-hours of initial training, followed by additional training on their respective training shifts:

- Shift Supervisor (1/shift)
- Unit Supervisor (1/shift)
- Assistant Shift Supervisor (1/shift)
- Reactor Operators (2/shift)
- Shift Technical Advisor (1/shift)
- Reactor Engineer (1)
- Day Shift Supervisor (1)
- Trainees (3)

The initial training procedures for changes in operations would involve 35 personnel. Assuming a 10-hour initial training program, it was estimated that 350 man-hours or 8.75 man-weeks would be required. Thus, the total labor required was 10.75 man-weeks/plant and the industry cost to implement the possible solution was ($2,270/man-week)(10.75 man-weeks)/plant or $24,000/plant.

NRC Cost: The NRC cost was estimated for three categories of activities: (1) develop a fuel behavior model; (2) support implementation of the solution; and (3) review operations and maintenance activities.

Technical support would be needed to establish PCI failure predictions and their correlations to release rates. The cost of developing the appropriate models was estimated to be $200,000. NRC review of implementation procedures and training procedures at individual plants was expected to require approximately 2 man-weeks/plant or $4,540/plant. Once the solution is implemented, a review of the results from power-maneuvering changes was anticipated to be required for 5 years. In addition, the improvement in any fuel assembly design changes will need to be assessed. This review effort was estimated to require 1 man-week/RY over

the 5 years subsequent to any changes at a cost of $11,350/plant. Thus, the total NRC cost to implement the possible solution was approximately $216,000/plant.

Total Cost: The total industry and NRC cost to implement the possible solution was estimated to be $240,000/plant.

Value/Impact Assessment

No calculations were performed for this issue since the potential risk reduction from the possible solution was negligible.

Other Considerations

Occupational Dose Factors: Localized dose rates are increased by fuel defects, as is the activity in liquid and gaseous release paths. If fuel failures exist, plants must maintain off-gas release rates within allowable limits. If a plant exceeds these limits or fails to clean up high activity in the coolant, a shutdown is required. In less severe cases, the plant will often stay within the allowable release limits by maintaining reduced levels of power until the next refueling outage. Because of the allowable release limits imposed on plant operations, the reduction in public risk resulting from the possible solution was expected to be negligible. In addition, the number of refueling outages was not expected to change significantly because of the resolution. Therefore, the changes in ORE were expected to be negligible.

Cost Avoidance: When a fuel failure occurs, all attempts are made to keep the plant in operation until a scheduled refueling outage. In most cases, this is possible; however, this procedure often means that a reduced level of power must be maintained in order to remain within allowable release limits. It is difficult to predict whether plants will shut down, remain operating at reduced levels for long periods of time, or remain operating at reduced levels for relatively short periods of time. In this issue, all plants were assumed to remain on line at the reduced level of 50% power for 30 days. This was assumed to be an average power level and an average period of time until a scheduled outage, considering the circumstances. Because of the reduced levels of output, the major potential expense was the cost of replacement power. The value assumed for the cost of replacement power during an outage was $300,000/day.[64] Therefore, under conditions of 50% output, the cost of replacement power would be $150,000/day and the cost of replacement power for 30 days at a plant operating at a 50% power level would be $4.5M.

CONCLUSION

Although all plants would be affected to some degree by the possible solution, the influence of the solution on core damage frequency and public consequence was insignificant. Fuel manufacturers have taken an active role in resolving the issue ever since it was identified. As a result, fuel failures are now rare and the significance of this issue has been diminished. The cost savings from replacement power far outweighed the costs associated with implementing the reactor manufacturers' changes.

Several problems were identified in the effort to improve the predictability of fuel performance and these were addressed by the staff in its revision to SRP[11] Section 4.2 in 1981. In addition to the economic incentive to the industry in

reliably predicting fuel performance, existing requirements were adequate to ensure continued low fuel defect rates; additional requirements would not decrease the number of fuel defects significantly. Therefore, this issue was DROPPED from further pursuit. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

3. NUREG-0471, "Generic Task Problem Descriptions (Categories B, C, and D)," U.S. Nuclear Regulatory Commission, June 1978.

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ITEM B-56: DIESEL RELIABILITY

DESCRIPTION

Historical Background

This issue was documented in NUREG-0471[3] and resulted from a review of LERs which indicated that onsite emergency diesel generators (EDGs) at operating plants were demonstrating an average starting reliability of about 0.94/demand. The goal for new plants, as expressed in Regulatory Guide 1.108,[216] was a starting reliability of 0.99/demand. The NRC awarded a contract to the University of Dayton Research Institute to identify the more significant causes of EDG unreliability. The Dayton University study was completed and the significant causes and recommended corrective actions were identified in NUREG/CR-0660.[217]

Safety Significance

Events (offsite and onsite) which result in a loss of offsite power necessitate reliance on the onsite EDGs for successful accident mitigation. Improvement of the starting reliability of onsite EDGs will reduce the probability of events which could escalate into a core-melt accident and thus could effect an overall reduction in public risk.

Possible Solution

The staff proposed a set of interim backfit requirements for operating plants that encompassed elements of Regulatory Guide 1.108[216] and the Dayton University recommendations.[217] These requirements were included in a proposed program[218] to establish a graded set of requirements based on the reliability actually exhibited by EDGs. This program adopted an EDG startup reliability of 0.95/demand as the minimum desired reliability and 0.9/demand as the minimum acceptable level of reliability. At or below the minimum desired level, licensees would be required to improve their EDG reliability and document their program for doing so. Below the minimum acceptable level, licensees would be required to improve or repair EDGs with reliability below the minimum acceptable level and perform a requalification program to demonstrate that the causes of the failures were corrected. The requalification program was intended to pass EDGs only if the reliability had been increased to 0.95/demand or greater.

The proposed interim program imposed a normal surveillance period of no more than 1 month. To increase assurance that a real change in reliability will be detected quickly, an increased test frequency was required when two or more failures had been experienced on an individual EDG in the previous 20 demands. However, the frequency of tests and the anticipated duration of the accelerated test frequency were not as restrictive as that recommended in Regulatory Guide 1.108.[216]

An extended out-of-service period could, in many cases, be necessary to allow sufficient time to correct the problems that caused low reliabilities. Therefore, the proposed program would allow out-of-service periods in excess of the existing 72-hour limit, when necessary, while at the same time placing a yearly limit on the cumulative time that a plant may operate in Modes 1 through 4 with one of the

EDGs of the power systems inoperable. The cumulative limit would vary depending upon the reliability of the in-service EDG with the lowest reliability.

PRIORITY DETERMINATION

A risk analysis was performed[64] using Oconee 3 and Grand Gulf Unit 1 as representative of PWRs and BWRs, respectively. Since the proposed position was expected to affect only those EDGs that had demonstrated a reliability of less than 0.95/demand, it was assumed that 25% of the EDG population would undergo a reliability improvement from 0.93 to 0.97/demand and 5% would undergo a reliability improvement from 0.9 to 0.97/demand (requalification).

Frequency Estimate

When the frequency of all core-melt scenarios (including EDG failure) was adjusted to include the above assumptions, it was found that the proposed solution would be expected to result in a significant core-melt frequency reduction for both the 25% EDG population and the 5% EDG population. The 25% EDG population, which was assumed to improve from 0.93/demand to 0.97/demand, would have core-melt frequency reductions of 1.7×10^{-5}/RY and 2.3×10^{-5}/RY for BWRs and PWRs, respectively. The 5% EDG population, which was assumed to improve from 0.9/demand to 0.97/demand, would have core-melt frequency reductions of 3.7×10^{-5}/RY and 7.5×10^{-5}/RY for BWRs and PWRs, respectively.

Consequence Estimate

Base case risk for both PWRs and BWRs was calculated by multiplying the expected frequency of each release category by the dose equivalent value for the category. Adjusted case risk was determined by the same technique using the core-melt frequency reduction calculated for the reliability improvement expected in the respective EDG populations (25% and 5%) for both PWRs and BWRs. The adjusted risk was subtracted from the base case risk and the public risk reduction obtained was multiplied by the appropriate number of PWRs and BWRs. The total public risk reduction calculated was 6.5×10^4 man-rem, with an average public risk reduction of about 1.5×10^3 man-rem/reactor.

Cost Estimate

Industry Cost: It was assumed that 30% of the 143 expected plants would institute a reliability improvement program. In addition, 5% of the plants were assumed to incur a major equipment (EDG) replacement and an associated loss of power production. Industry costs were estimated for revision of operating procedures and personnel training, installation of additional equipment (air dryers, dust-tight enclosures for electrical contacts, EDG room ventilation ducting, etc.) and ongoing increases in operation and maintenance costs. Thus, the total industry cost was estimated to be $46M.

NRC Cost: The cost to complete resolution of the issue, review and approve new requirements, and issue implementation orders was estimated to be $130,000. Review of plant responses to orders and periodic reports expected from plants which must develop and initiate EDG reliability improvement programs and long-term surveillance of the industry was estimated at $1M. Thus, total NRC cost was estimated to be $1.1M.

Total Cost: The total industry and NRC cost associated with the solution to this issue was $(46 + 1.1)M or $47.1M.

Value/Impact Assessment

Based on a potential public risk reduction of 6.5×10^4 man-rem and a cost of $47.1M, the value/impact score was given by:

$$S = \frac{6.5 \times 10^4 \text{ man-rem}}{\$47.1M}$$

$$= 1{,}380 \text{ man-rem/\$M}$$

Other Considerations

An unusually significant avoided accident cost was calculated for the resolution of this issue. This cost represented the expected savings to the industry from lowering the core-melt probability by implementation of a specific improvement and was calculated by multiplying the expected cost of the loss of a plant (~$3 Billion) by the expected total core-melt frequency reduction. In this instance, the avoided accident cost (savings to the industry) was estimated to be $30M.

CONCLUSION

The calculated value/impact score was indicative of a medium priority assignment; however, other factors prevailed. The very large estimated total public risk reduction (6.5×10^4 man-rem) and high expected core-melt frequency reduction ($>10^{-5}$/RY) elevated the priority of this issue. In addition, if the averted accident cost (industry savings) were subtracted from the total resolution cost, a value/impact score of 3,800 man-rem/$M would result. Therefore, the issue was given a high priority ranking (See Appendix C).

The issue was resolved by the inclusion of guidance on EDG reliability in Regulatory Guide 1.160[1484] which was issued as part of the Maintenance Rule (10 CFR 50.65). This guide endorsed NUMARC 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which addressed the optimization of EDG reliability and availability and contained an example of an acceptable means of establishing performance criteria and/or goals for EDGs. In addition, Regulatory Guide 1.9,[1483] Rev. 3 was issued to integrate into a single document pertinent guidance previously addressed in the following documents: Regulatory Guide 1.9,[1483] Rev. 2; Regulatory Guide 1.108,[216] Rev. 1; and Generic Letter 84-15.[1487] As a result, Regulatory Guide 1.108,[216] Rev. 1 was withdrawn.[1485] Thus, this issue was RESOLVED and new requirements were established.[1486] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

REFERENCES

3. NUREG-0471, "Generic Task Problem Descriptions (Categories B, C, and D)," U.S. Nuclear Regulatory Commission, June 1978.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

216. Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, August 1976, (Rev. 1) August 1977.

217. NUREG/CR-0660, "Enhancement of On-Site Emergency Diesel Generator Reliability," U.S. Nuclear Regulatory Commission, February 1979.

218. Memorandum for D. Eisenhut, et al., from S. Hanauer, "Diesel Generator Reliability of Operating Plants," May 6, 1982.

1483. Regulatory Guide 1.9, "Selection, Design, and Qualification of Diesel-Generator Units Used as Standby (Onsite) Electric Power Systems at Nuclear Power Plants," March 1971, (Rev. 1) November 1978, (Rev. 2) December 1979, (Rev. 3) July 1993.

1484. Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1993.

1485. Federal Register Notice 58 FR 41813, "Regulatory Guide; Withdrawal," August 5, 1993.

1486. Memorandum for J. Taylor from E. Beckjord, "Resolution of Generic Safety Issue B-56, 'Diesel Generator Reliability,'" June 29, 1993.

1487. NRC Letter to All Licensees of Operating Reactors, Applicants for An Operating License, and Holders of Construction Permits, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability (Generic Letter 84-15)," July 2, 1984.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ITEM B-64: DECOMMISSIONING OF REACTORS

DESCRIPTION

Decommissioning is defined as the orderly retirement of a nuclear facility from service and the safe disposition of the remaining radioactivity. 10 CFR 50.82 provides the regulations that govern the termination of licenses. The NRC may require information from a licensee to demonstrate that the methods and procedures to be used for decontamination and for disposal of radioactive materials will provide reasonable assurance that the dismantling and disposal will not adversely affect public health and safety. 10 CFR 50.33(f) requires that OL applicants show that they possess (or have reasonable assurance of obtaining) funds necessary to cover the estimated costs of permanently shutting down their plants and maintaining them in a safe condition. Methods and procedures considered acceptable to the staff for termination of licenses were delineated in Regulatory Guide 1.86.[85] This NUREG-0471[3] item was established to address development of additional guidance on decommissioning.

CONCLUSION

At the time this issue was first evaluated, the staff had decommissioning rule amendments under development (See References 167, 172, 197, and 1568). Technical evaluations had been completed[182,227] and a draft rulemaking environmental impact statement had been prepared in January 1981. The staff had also prepared proposed rule amendments[193] that were intended to ensure that decommissioning of all licensed facilities would be accomplished in a safe and timely manner and that adequate licensee funds would be available for this purpose. Based on the status of the proposed rule amendments, this issue was considered nearly-resolved and resolution was pursued.

Following Commission comments on the draft rule amendments submitted by the staff in SECY-87-309,[1569] the final rule amendments were resubmitted in SECY-88-94[1570] and later issued[1364]; the FEIS[173] was published in August 1988. Following issuance of the amendments, the staff proceeded to develop an SRP[11] Section for use in its review of licensee decommissioning plans. However, this effort was superseded in July 1994 with a proposed revision to the rule. This proposed revision was submitted to the Commission in SECY-94-179[1571] following which an SRM[1572] outlining staff actions was issued. Thus, based on the issuance of the rule amendments in 1988, this issue was RESOLVED[1574] and new requirements were issued. Consideration of a license renewal period of 20 years would not affect the resolution.

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227. NUREG/CR-0130, "Technology, Safety, and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station," U.S. Nuclear Regulatory Commission, June 1978.

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1568. Federal Register Notice 46 FR 11666, "10 CFR Parts 30, 40, 50, 70 and 72 Decommissioning Criteria for Nuclear Facilities; Notice of Availability of Draft Generic Environment Impact Statement," February 10, 1981.

1569. SECY-87-309, "Final Rule Amendments to 10 CFR Parts 30, 40, 50, 51, 70, and 72: General Requirements for Decommissioning Nuclear Facilities," December 17, 1987.

1570. SECY-88-94, "Final Rule Amendments to 10 CFR Parts 30, 40, 50, 51, 70, and 72: General Requirements for Decommissioning Nuclear Facilities (SECY-87-309)," April 5, 1988.

1571. SECY-94-179, "Notice of Proposed Rulemaking on Decommissioning of Nuclear Power Reactors," July 7, 1994.

1572. Memorandum for J. Taylor and K. Cyr from J. Hoyle, "SECY-94-179 - Notice of Propose Rulemaking on Decommissioning of Nuclear Power Reactors and COMKR-94-002 - Decommissioning of Nuclear Power Reactors and Comments on SECY-94-179," October 5, 1994.

1574. Memorandum for J. Taylor from R. Bernero, "Resolution of Issue Number B-64, 'Decommissioning of Reactors,' of the Generic Issue Management Control System," September 26, 1994.

ISSUE 2: FAILURE OF PROTECTIVE DEVICES ON ESSENTIAL EQUIPMENT

DESCRIPTION

Historical Background

This issue was identified[4] after a review of LERs involving the failure or degraded performance of essential equipment that resulted from the failure of protective devices such as fuses and circuit breakers. The affected systems included plant control, engineered safety features, and plant protection. In this evaluation, these affected systems are referred to as essential equipment.

The observed protective device failures were not limited to overcurrent devices but also occurred in torque and limit switches and overspeed trips. The essential equipment failures may have been caused by: (a) essential equipment component failures; or (b) protective device failures such as improper application, maladjustment, or protective device component failures.

The concern raised in this issue is that the failure rates of essential equipment that are assumed in PRAs may not have accounted for those failures of protective devices that also disable the essential equipment, hence leading to underestimation of risk. A further discussion of this issue was published in NUREG-0705.[44]

Safety Significance

If PRAs do not properly account for the failures of essential equipment as a result of protective device failures, the assumed failure rates may be too optimistic. This can seriously affect industry and NRC priorities in expending resources to address safety concerns. Since essential equipment on all plants contain protective devices, this issue affects all operating and future plants.

Possible Solution

Given the nature of PRA and the limitations of its use in the regulatory arena, it was not likely that a solution to this issue could result in additional requirements to be imposed on plants. However, a possible solution could be an information notice to alert licensees and PRA analysts of any shortcomings in the PRA methodology or assumptions so that plant risk is not underestimated in PRAs.

PRIORITY DETERMINATION

This issue addressed PRA analysis methodology and the validity of certain assumptions including: (a) the composition of failure rate data; and (b) the modeling of essential equipment and their associated protective devices in the PRAs. In considering the relation between (a) and (b) above, four analysis possibilities can develop:

(1) The failure data is given for essential equipment, including their protective devices, and the plant modeling accounts for essential

equipment including protective devices. In this case, risk estimates are done properly.

(2) Failure data is given for essential equipment without protective devices and the plant model accounts for essential equipment without protective devices; the model deals with protective devices separately. Also, in this case, risk estimates are done properly.

(3) Failure data is given for essential equipment with protective devices, but the model is for essential equipment without protective devices; protective devices are modeled separately. In this case, the protective device failure rates are considered twice. This analysis tends to overestimate plant risk.

(4) Failure data is given for essential equipment without protective devices, but the model is for essential equipment with protective devices, i.e., the protective device failure rates are not considered. This analysis tends to underestimate plant risk.

However, knowledgeable PRA practitioners believe that present PRAs usually model the protective devices explicitly but sometimes include them with the essential equipment and account for their failure rates.

There are several sources of generic data bases that are used by the NRC and the industry to conduct PRAs. These data bases include the Nuclear Computerized Library for Assessing Reactor Reliability (NUCLARR),[1327] IEEE Std 500,[194] and the Component Failure Data Handbook (EGG-EAST-8563, INEL, June 1989). Also, some firms that conduct PRAs maintain their own generic data bases.

The sources of the failure and demand information used in the generic data bases include LERs, Nuclear Plant Reliability Data System (NPRDS) records, and other industry reports. These sources of failure data are affected by the interpretation by plant personnel of: (1) the nature of the failure; and (2) the boundaries of the affected system or component. For example, a control circuit that actuates a component may be included within the boundary of that component. Likewise, in generating the failure rate, some protective devices (e.g., fuses) that are installed in or on the body of the component may be considered as part of that component. On the other hand, circuit breakers, especially those not located in the proximity of the affected equipment, are considered as separate components and are usually modeled as such.

Support system failures that lead to failure of a front-line system typically are treated as separate system failures and are modeled as such. For example, CCW system failure leads to a loss of lube oil cooling which in turn leads to pump failure. In this case, there is only one valid failure: the CCW system. The induced failures are accounted for in the model through the dependency matrix.

CONCLUSION

On the basis of discussions with knowledgeable PRA practitioners, existing practice was to include protective devices in PRAs, either explicitly or as an element of the component failure rate. Therefore, it was concluded that this issue did not represent a safety concern and was DROPPED from further

consideration. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

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1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 24: AUTOMATIC ECCS SWITCHOVER TO RECIRCULATION

DESCRIPTION

Historical Background

This issue was raised by the staff following a review[28,29] of operating events that indicated a significant number of ECCS spurious actuations, particularly, the four events that occurred at Davis-Besse during 1980.

ECCS operation has two different phases in PWRs: injection and recirculation. The injection phase involves initial cooling of the reactor core and replenishment of the primary coolant following a LOCA. In this phase, the ECCS pumps typically take suction from the refueling water storage tank (RWST). The recirculation phase provides long-term cooling during the accident recovery period. The ECCS is realigned in the recirculation phase to take suction from the containment sump.

Switchover from injection to recirculation phase involves realignment of several valves and may be accomplished by: (1) manual operations to realign the valves; (2) fully automatic realignment of the valves; or (3) automatic realignment of some valves, followed by manual completion of the process (semi-automatic). Each option is vulnerable in varying degrees to human errors, hardware failures, and common cause failures.

Safety Significance

During a LOCA, ECCS pump suction must be switched from the RWST to the containment sump before RWST inventory is lost, or loss of the ECCS pumps will occur. Switching to the sump early could adversely affect the accident because the containment sump may not have enough inventory to provide pump suction. The automatic and the semi-automatic switchovers reduce the risk of human error but have a slight increase in risk for inadvertent actuations. This issue affects PWRs only.

Possible Solutions

The two possible solutions to this issue are alternate cases requiring fully-automatic or semi-automatic switchover to the containment sump. The fully-automatic switchover could be implemented by a system that would monitor the water level in the RWST and, at a preset level, automatically realign the ECCS to take suction from the containment sump. The semi-automatic switchover could be implemented by a system that would involve automatic alignment of some valves and manual completion of the switchover process.

PRIORITY DETERMINATION

Assumptions

All operating or proposed PWRs may be affected by this issue and the Oconee 3 PRA was assumed to be representative of PWRs. LERs between 1987 and 1990 were used

to calculate the potential risk from spurious actuations. The spurious actuation probability was then used for the automatic switchover and modified for the semi-automatic switchover.

The base case of the possible solutions assumes manual switchover. Some PWRs are already fully automatic and some are semi-automatic. It was assumed that all PWRs with manual switchover could benefit from the possible solutions; since some PWRs are already automatic, some (fixed) costs will be spread over fewer reactors than calculated.

Frequency Estimate

The issue to be addressed is the failure of an operator to open containment sump suction valves at the start of recirculation. New parameters were introduced to provide estimates of recirculation system unavailability corresponding to manual, automated, and semi-automated switchover options.[29] The new parameters were then updated for human error rate estimates given in NUREG/CR-4639.[1327] The updated parameters were then factored into the core-melt frequency.

The frequencies of the affected release categories were summed for each case to give the total core-melt frequency for the three cases considered.[64]

Base Case (Manual):	3.1×10^{-6}/RY
Semi-Automatic Switchover:	1.6×10^{-6}/RY
Fully-Automatic Switchover:	1.3×10^{-6}/RY

The adjusted case core-melt frequencies were calculated by substituting the adjusted probabilities into the failure scenarios which require sump suction valves to be opened for success.[64] Thus, the potential reduction in core-melt frequency was estimated to be 1.5×10^{-6}/RY and 1.8×10^{-6}/RY for the semi-automatic and the fully-automatic switchover options, respectively.

Consequence Estimate

Multiplying the affected release categories by the estimated public dose, the total affected public risk for the three cases were as follows:

Base Case (Manual):	7.5 man-rem/RY
Semi-Automatic Switchover:	3.2 man-rem/RY
Fully-Automatic Switchover:	3.0 man-rem/RY

Thus, the estimated risk reduction was 4.3 man-rem/RY and 4.5 man-rem/RY for the semi-automatic and fully-automatic switchover, respectively. Based on an average remaining operating life of 28.8 years for PWRs, this reduction was estimated to be 125 man-rem/reactor and 130 man-rem/reactor for the semi-automatic and fully automatic switchover, respectively.[64]

Installing automatic or semi-automatic systems reduces human error. However, the estimated risk reduction from installing actuation systems that are less prone to human error was offset somewhat by an increased risk due to spurious actuations.

Cost Estimate

Industry Cost: The cost was estimated to be the same for both semi-automatic and fully-automatic switchover at all affected PWRs. The estimates for TS, maintenance procedure, and operating procedure changes were taken from NUREG/CR-4627.[961] The implementation costs were calculated as follows:

Design/QA	= 8 man-weeks
Install/Calibrate/Test Equipment	= 1 man-week
Safety Analysis	= 8 man-weeks
TS Changes	= 16 man-weeks
Training	= 8 man-weeks
Hardware (New Controller/Logic Module)	= $5,000
Revise Operating and Maintenance Procedures	= $7,800

Thus, the total estimated cost was $110,000/plant, based on 41 man-weeks at $2,270/week and a fixed cost of $12,800.

Operation and maintenance of the possible solutions were estimated to require an additional 1 man-week/RY. Over the average remaining operating life of 28.8 years, and at a discount rate of 5%, this cost was estimated to be $34,000/reactor.

NRC Cost: It was estimated that 1 man-year of contractor effort would be required to research potential design changes and prepare a regulatory analysis. A project manager would be required at 10% of the contractor cost. At an estimated cost of $100,000/man-year, the contractor and project manager cost was estimated to be $110,000.

Eight man-weeks would be required to review and evaluate each plant's design, safety analyses, QA documentation, TS changes, and procedure changes. With an assumed labor cost of $2,270/week, this cost was estimated to be $18,000/reactor.

Total Cost: The total industry and NRC cost associated with the possible solutions was estimated to be $272,000/reactor.

Value/Impact Assessment

Separate value/impact scores were calculated for the semi-automatic switchover and the fully-automatic switchover possible solutions.

(1) Semi-Automatic: $S = \frac{125 \text{ man-rem/reactor}}{\$0.272\text{M/reactor}}$

$= 460$ man-rem/$M

(2) Fully-Automatic: $S = \frac{130 \text{ man-rem/reactor}}{\$0.272\text{M/reactor}}$

$= 478$ man-rem/$M

Other Considerations

Since much of the work will be in radiation zones, a significant occupational dose will occur. The dose rate was assumed to be 2.5 millirem/hr for work outside containment.[64] The occupational dose was assumed to be the same for both possible solutions. The implementation dose was calculated at 0.5 man-rem/reactor and total operation and maintenance dose at 0.6 man-rem/reactor. This resulted in a total ORE of 1 man-rem/reactor.

CONCLUSION

Based on the value/impact score and the potential risk reduction for PWRs with manual switchover, this issue was given a MEDIUM priority ranking (See Appendix C). Furthermore, since the uncertainties in the assumptions and analysis were very large, a more extensive study would be required to resolve this issue with reasonable confidence in the conclusion, including more reliable estimates of equipment reliability, human error rates, and competing risks. The resolution of this issue was expected to address the safety concern of Issue 156.3.5 as well as the impact of a license renewal period of 20 years.[1564]

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1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 29: BOLTING DEGRADATION OR FAILURE IN NUCLEAR POWER PLANTS

DESCRIPTION

Historical Background

Prior to 1981, the number of bolting-related incidents reported by licensees was on the increase. A large number of these were related to primary pressure boundary applications and major component support structures. As a result, there was concern for the integrity of the primary pressure boundary in operating plants and the reliability of the component support structures following a LOCA or earthquake. This issue was identified by the ACRS.[1384]

There are numerous bolting applications in nuclear power plants the most crucial of which are those constituting an integral part of the primary pressure boundary such as closure studs and bolts on reactor vessels, reactor coolant pumps, and steam generators. Failure of these bolts or studs could result in the loss of reactor coolant that could jeopardize the safe operation of the plants. Other bolting applications, such as component support and embedded anchor bolts or studs, are essential for withstanding transient loads created during abnormal or accident conditions. A report summarizing bolting failure experience was issued by DL/NRR.[184]

Safety Significance

At the time of this evaluation in 1983, there had been a total of 44 reported bolting incidents most of which were discovered either during refueling outages or scheduled ISI or maintenance/repair outages. These incidents had no immediate impact on public health and safety since they had not resulted in any accident. However, degradation or failure of such studs and bolts constitutes a reduction in the integrity of the primary pressure boundary.

Concern was compounded by the fact that there was no reliable NDE method to detect the cracking or degradation of bolts or studs resulting from the principal modes of failure: stress corrosion, fatigue, erosion corrosion, and boric acid corrosion. Visual examination was the only reliable method to discover degradation by boric acid corrosion or erosion corrosion. In almost all cases, this required disassembly of the component in order to inspect the bolts or studs. If there is no clear evidence of boric acid leakage to the surroundings, bolting degradation by boric acid corrosion can potentially be undetected until the bolts or studs completely fail. Under the existing ISI program, visual inspection of bolts was not a mandatory requirement and UT inspection was not required on pressure-retaining bolts or studs with diameters less than 2 inches. A major accident such as a LOCA could conceivably occur due to undetected extensive bolting failure of the primary pressure boundary.

Possible Solution

Because bolting has a wide range of application in nuclear power plants, there was no simple solution to the problem. Therefore, in order to minimize the potential bolting problems in new power plants, improvements in one or all of the

following five areas could be recommended: design, materials, fabrication, installation, and ISI. For this analysis, the focus was placed on improving the efficiency and adequacy of ISI programs.

PRIORITY DETERMINATION

Frequency Estimate

Based on a review of the 44 bolting incidents reported by PWR licensees up to the time of this evaluation, the principal causes of bolting failure or degradation were classified as stress corrosion, fatigue, boric acid corrosion, erosion corrosion, and other types. Nineteen of the 44 incidents were identified as resulting from stress corrosion, the most common cause of bolting failure. Boric acid corrosion was the second most common cause of bolting failure or degradation reported. Twelve resulted from boric acid corrosion. The remaining 13 incidents were either fatigue, erosion corrosion, or other types. No bolting failures in BWRs were reported.

Sixteen of the 44 reported incidents were related to primary pressure boundary bolting applications such as various closure studs in reactor vessels, pressurizers, steam generators, and hold-down bolts in various types of valves. Thirteen incidents related to component support structures, such as the column support or embedded anchor bolts or studs of steam generators, reactor vessels, reactor coolant pumps, and piping restraints, were reported. Although failure of such bolts or studs will not normally impair the normal operation of a plant, extensive failure of such bolts or studs could cause component damage or multiple piping failure under abnormal or accident conditions such as a LOCA or an earthquake. The 44 bolts or stud failures occurred in about 350 RY of experience. Thus, the frequency of corrision-initiated events was 44/350 event/RY or 1.3×10^{-1} event/RY.

Based on experience, there was a good chance that the corrosion would be discovered and the studs replaced before failure occurred. However, it was conservatively assumed that 10% of the bolts or studs will not be discovered before they failed and will result in a small break LOCA (S2). Therefore, the frequency (F) of corrosion-initiated events was estimated to be 1.3×10^{-2} S2 event/RY.

Twenty-nine of the reported incidents or 66% had a direct potential for causing a large-break LOCA due to bolting or stud failure in restaints for large piping, component supports, or steam generator manways when these hold-down devices have degraded to the point that they will not provide the necessary support following a water hammer or seismic event. However, even though the actual determination was complex, the S2 event was believed to be the most limiting.

Consequence Estimate

An S2 event can result in a wide spectrum of consequences, depending on whether or not the engineered safety features are required to function or whether they do function. Using WASH-1400[16] S2 sequences with the frequency estimated above, the release was determined to be 3×10^{4} Curies/RY.

The total whole-body man-rem dose was obtained by using the CRAC Code[64] for the particular release category. A uniform population density of 340 people per

square mile (average for U.S. domestic sites) and a typical (midwest plain) meteorology were assumed. Therefore, the estimated public risk was 3.5×10^3 man-rem/RY. For 43 plants with an average remaining lifetime of 30 years, the potential risk reduction was 4.5×10^5 man-rem.

Cost Estimate

Industry Cost: The proposed fix could vary considerably depending on the type and depth of solution sought. However, the most probable fix was to visually inspect bolts or studs using an improved UT inspection technique and a more frequent inspection schedule. This represented an increase in surveillance and would require extra effort during each plant refueling outage. Because of the wide variety of uses of studs and bolts for safety functions in nuclear plants, the actual cost would vary greatly.

Based on the information[64] provided, an interim and simple fix would be to inspect studs and bolts only on components that had been opened for inspection or maintenance during a refueling outage. This would require a minor increase in surveillance and would not require an extension of outage time. It was estimated that 3 man-weeks/plant of extra effort would be required per 18-month refueling schedule and 40 man-weeks/plant to allow for administrative overhead. At $100,000/staff-year, the cost (C) of the increased surveillance over the 30-year life of a plant was given by:

$$C = \$\left[\frac{(3)(30/1.5) + 40}{52}\right](0.1)M/\text{reactor}$$

$$= \$0.2M/\text{reactor}$$

If, however, each plant was required to inspect 10% of the bolts or studs in primary system components per refueling outage, whether open for inspection or not, then based on an 18-month refueling schedule, each plant would have inspected 200% of its bolts or studs over its 30-year lifetime. (This inspection frequency should detect any bolt degradation that might occur.) This would represent an increase in surveillance and would require an extension of outage time by 1.5 working days. At $300,000/day for replacement power, the total cost (C) over the plant life was given by:

$$C = \$(30/1.5)(0.3)(1.5)M/\text{reactor}$$

$$= \$9M/\text{reactor}.$$

NRC Cost: The NRC cost was negligible in comparison to the industry cost.

Value/Impact Assessment

(1) For inspecting bolts on disassembled components only, the value/impact score was given by:

$$S = \frac{4.5 \times 10^5 \text{ man-rem}}{\$(0.2)(43)M}$$

$$= 53{,}000 \text{ man-rem}/\$M$$

(2) For inspecting 10% of the bolts, the value/impact score was given by:

$$S = \frac{4.5 \times 10^5 \text{ man-rem}}{\$(9)(43)M}$$

$$= 1{,}160 \text{ man-rem/\$M}.$$

Uncertainties

The uncertainties in the estimates of accident frequencies and consequences were such that, if they lowered the value/impact score by an order of magnitude, the score would still be above a threshold that would warrant resolution of the issue. As the cost estimates increase for specific solutions (particularly when plant shutdown or extended shutdowns are required), the value/impact scores decrease and could affect the priority ranking. If the cost estimates associated with inspecting 10% of the bolts are off by a large factor, the potential risk reduction would still be high.

Other Considerations

(1) A secured reactor primary system pressure boundary, which depends on the integrity of the system's piping and components, is an integral part of the defense-in-depth concept embodied in the design of nuclear power plants to protect against a core-melt. Also, some safety system functions rely on a secured pressure boundary to prevent or mitigate the consequences of an event. Accordingly, inspection of 10% of the bolts per refueling outage (200% over the lifetime of the plant) provides assurance that the primary system pressure boundary will not be breached by failed bolts or studs.

(2) When the averted costs of cleanup following a LOCA are considered, the value/ impact scores calculated above become more favorable. It was estimated that the averted occupational dose of inspection versus reduction due to accident dose would fall between a PWR-8 or PWR-9 event and a PWR-1 to PWR-7 event. This represented an averted dose between 2,400 to 8,000 man-rem.

CONCLUSION

Based on the above value/impact scores, this issue was given a high priority ranking (See Appendix C). In resolving the issue, the staff took into consideration previous actions taken by the NRC to address the concerns related to threaded fasteners: Bulletin Nos. 82-02,[1129] 87-02,[1389] and 89-02[1388]; Information Notice Nos. 86-25,[1393] 89-22,[1390] 89-56,[1391] and 89-70[1392]; and Generic Letter Nos. 87-02[1387] and 88-05.[1386]

The staff's regulatory analysis, NUREG-1445,[1398] proved to be inconclusive regarding a mandatory program on safety-related bolting for operating plants. The staff's technical findings were documented in NUREG-1339[1395] which endorsed the recommendations of independent studies performed by the industry Joint Task Group on Bolting. This group was set up by AIF, EPRI, and the Materials Properties Council and its studies resulted in EPRI NP-5769, "Good Bolting Practices," and three EPRI video training tapes on "Pressure Boundary Bolting Problems."

The staff concluded that leakage of bolted pressure joints was possible, but catastrophic RCPB joint failure that could lead to significant accident sequences was highly unlikely. This conclusion was based on: (1) operating experience; (2) actions taken through bulletins, generic letters, and information notices; and (3) proposed industry actions. Generic Letter No. 91-17[1385] was issued to licensees to: (1) implement the industry bolting integrity program, as presented in the EPRI report and video tapes; and (2) continue actions in accordance with commitments made in response to NRC generic letters and bulletins. Thus, this issue was RESOLVED and no new requirements were established. However, in order to improve the review of future plants and significant modifications to operating plants, the staff recommended that a new SRP[11] Section be developed to codify existing guidance and industry recommendations.[1394] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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1394. Memorandum for J. Taylor from E. Beckjord, "Resolution of Generic Safety Issue 29, 'Bolting Degradation or Failure in Nuclear Power Plants,'" October 25, 1991.

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ISSUE 38: POTENTIAL RECIRCULATION SYSTEM FAILURE AS A CONSEQUENCE OF INGESTION OF CONTAINMENT PAINT FLAKES OR OTHER FINE DEBRIS

DESCRIPTION

Historical Background

This issue was identified[496] when AEOD expressed concerns about the use inside containment of a particular polymer coating that could flake off and fail when subjected to DBA conditions. In addition to the concern for paint flakes, AEOD also raised concerns about fibrous insulation and other debris that could pass through sump screens, but could not pass through the more restrictive clearances present in systems that take suction from the containment sump during the recirculation phase of accident mitigation.

Safety Significance

Potential safety concerns stemming from the presence of paint debris in the containment building during a LOCA include the following: (1) blockage of containment emergency sump debris screens; (2) blockage of containment building spray system nozzles and system flow passages associated with residual heat removal/safety injection systems and their equipment; and (3) degradation of ECCS performance by the entrainment of fine particles of paint debris. This issue is applicable to all plants.

Possible Solution

In the resolution of Issue A-43, the staff evaluated the performance of the containment emergency sump in providing a clean, reliable source of water during a LOCA and during long-term recirculation following a LOCA. Specifically, the evaluation included analysis of the transport of fine debris.

In its application to operate Comanche Peak Steam Electric Station, Units 1 and 2, Texas Utilities Electric Company (TUEC) performed an analysis in support of its request to amend its FSAR to eliminate the commitment that coatings inside the reactor containment building be qualified. This analysis considered the potential for, and effects of, debris blockage of the containment building emergency sumps. TUEC followed the guidance and methodology developed by the staff in the resolution of Issue A-43 and concluded that debris generated by the failure of all coatings inside the containment building under DBA conditions would not unacceptably degrade the performance of post-accident fluid systems. The staff's SER on the TUEC analysis was published in Supplement No. 9 to NUREG-0797.[1332]

CONCLUSION

The general concerns of sump blockage were addressed in the technical findings reported in NUREG-0897,[1057] the revisions to Regulatory Guide 1.82,[1058] SRP[11] Section 6.2.2, and Generic Letter 85-22.[1059] The TUEC analysis provided data[1057] on the significance of containment sump blockage caused by paint flakes or other fine debris. Thus, this issue was DROPPED from further consideration as a new and

separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1057. NUREG-0897, "Containment Emergency Sump Performance," U.S. Nuclear Regulatory Commission, (Rev. 1) October 1985.

1058. Regulatory Guide 1.82, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident," U.S. Nuclear Regulatory Commission, (Revision 1) November 1985.

1059. NRC Letter to All Licensees of Operating Reactors, Applicants for Operating Licenses, and Holders of Construction Permits, "Potential for Loss of Post-LOCA Recirculation Capability Due to Insulation Debris Blockage (Generic Letter 85-22)," December 3, 1985.

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1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 39: POTENTIAL FOR UNACCEPTABLE INTERACTION BETWEEN THE CRD SYSTEM AND NON-ESSENTIAL CONTROL AIR SYSTEM

DESCRIPTION

This issue was identified in a 1980 AEOD memorandum[107] and concerned the slow loss of control air pressure in the pneumatic control system of BWR scram systems. Air pressure loss at certain low rates can allow a sufficient discharge of water from the scram outlet valves to fill or almost fill the scram discharge header before a scram can be initiated and the rods inserted either by manual or automatic scram initiation. A full or almost full header would prevent scram of the control rods.

CONCLUSION

The safety concern of this issue was addressed in Issue 25, "Automatic Header Dump on BWR Scram System," which was resolved with requirements. Therefore, consideration of the impact of a license renewal period of 20 years was not necessary.[1564]

REFERENCES

107. Memorandum for H. Denton from C. Michelson, "Potential for Unacceptable Interaction Between the Control Rod Drive System and Non-Essential Control Air System at the Browns Ferry Nuclear Plant," August 18, 1980.

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ISSUE 57: EFFECTS OF FIRE PROTECTION SYSTEM ACTUATION ON SAFETY-RELATED EQUIPMENT

DESCRIPTION

Historical Background

This issue was identified at an NRC Operating Reactor Events meeting on January 7, 1982,[1027] and addressed fire protection system (FPS) actuations that resulted in adverse interactions with safety-related equipment at operating nuclear power plants. Events showed that safety-related equipment subjected to FPS water spray could be rendered inoperable. The events also indicated numerous spurious actuations of the FPS initiated by operator testing errors or by maintenance activities (e.g., welding), steam, or high humidity in the vicinity of FPS detectors. At the Reactor Events meeting, OIE was assigned the responsibility to review previous FPS actuations and consider development of an Information Notice; in addition, DE/NRR was expected to review the events and consider the need for modifications to FPS requirements or licensing review procedures.

An AEOD memorandum[1028] issued on January 28, 1982 provided examples of FPS actuation interactions in addition to those identified at the Reactor Events meeting and suggested that all types of FPS suppression systems (e.g., water, halon, CO_2, and other chemicals) be considered in the OIE and NRR reviews. An NRR response to the AEOD concerns was provided in August 1982.[510]

In November 1982, DE/NRR presented a review of FPS regulations and guidelines regarding interactions between FPS features and plant safety systems as well as a review of operating experience involving such interactions. It was concluded that, if existing guidelines were properly implemented, such interactions should be minimized. However, LERs indicated that the guidelines had not been properly implemented at some plants.

On June 22, 1983, IE Information Notice 83-41[1025] was issued to alert licensees and provided examples of previous experiences in which actuation of fire suppression systems caused damage or inoperability of systems important to safety. The IE Notice indicated that the plant Fire Hazards Analysis required by 10 CFR 50 Appendix R and by the related NRR BTP[11] required, not only consideration of the consequences of a postulated fire, but also consideration of the effects of fire-fighting activities. The IE Notice stated that a properly conducted Fire Hazards Analysis in conjunction with a physical walk-down of plant areas would have identified instances where minor modifications such as shielding equipment and sealing conduit ends would have reduced equipment water damage from inadvertent FPS operation. The IE Notice indicated that none of the reported events resulted in a serious impact on the functional capability of a plant to protect public health and safety. However, examples were given where it would not be difficult to extrapolate actual occurrences into a sequence of events that could lead to more serious consequences.

Safety Significance

FPS actuations which result in adverse interaction with plant safety systems reduce the availability of such safety systems needed to achieve safe plant shutdown or to mitigate a postulated accident.

Possible Solution

A possible solution was to follow up IE Information Notice 83-41[1025] with an IE Bulletin that would require licensees to reevaluate their implementation of the FPS guidelines regarding adverse interactions with safety systems, to ensure that safety-related equipment not damaged by fire can perform its intended function during and following an FPS actuation.

PRIORITY DETERMINATION

Frequency Estimate

In order to estimate the frequency of FPS actuations resulting in adverse interactions with plant safety systems, a review of plant operating events over a four-year period from 1979 through 1982 was conducted. During this period, there were 30 FPS actuations where FPS suppressant (water or gas) was released or the FPS actuation circuitry isolated a safety system. Of these 30 occurrences, 24 were inadvertent and directly related to personnel error during maintenance and/or test work on the FPS or systems adjacent to FPS detectors, 2 resulted from system steam leaks which actuated FPS heat/smoke detectors, and 2 were FPS water valve gradual leaks without actual FPS actuation. One occurrence was a planned FPS suppressant (CO_2) release test and the other was due to a fire in the area.

During this same time period, there were some additional inadvertent FPS actuations without release of fire suppressant since there was no heat to melt the sprinkler head fusible links. These cases had no potential interaction effect and were not considered further. Of the 30 FPS actuations summarized above, 18 caused an interaction with a safety system; 16 of these involved only a single train of redundant(2) train system while the other 2 involved redundant trains of a given safety system. All but 2 of the 18 interactions involved open head deluge water sprinkler systems spraying water onto safety system equipment or oil supplies. The remaining 2 interactions involved FPS actuation circuitry interacting with the control circuitry of a single train of a safety system but no release of suppressant. The systems affected by the single train and redundant train interactions are tabulated in Table 3.57-1.

In order to estimate the contribution of these interactions to potential core-melt accidents, Table 3.57-1 was used to identify typical interactions with systems represented in plant dominant accident sequences leading to core-melt. The FPS interaction with redundant trains of a diesel generator system (in the above case, water contamination of the fuel oil common to both diesel generators) represented a potential common mode failure of the onsite emergency AC power function.

The HPCI and RCIC interactions above actually constitute safety system single train interactions since each system is backed by the ADS plus LPCI. However, for conservatism, it was assumed that these data were equivalent to one redundant

train interaction representing potential common mode failure of high pressure injection protection against an SBLOCA.

TABLE 3.57-1

Systems Affected by Interactions

Redundant Train Interactions	
System	Occurrences
Diesel-Generator	1
Aux Bldg., Fuel Bldg. Ventilation-Charcoal Filters	1
	2

Single Train Interactions	
System	Occurrences
Diesel-Generator	4
ESF, SGTS Charocal Filters	4
RCIC	2
Core Spray	2
HPCI	2
Hydrogen Recombiner	1
RPS MG Set	1
	16

There was one redundant train and several(4) single train interactions causing inoperability of charcoal filters of various safety grade ventilation systems. However, these interactions were not contributors in core-melt accident sequences even though they can adversely affect radiation releases from a plant following an accident. These occurrences were not considered in estimating contribution of these interactions to core-melt accidents.

Consequently, it was assumed the above data represented a potential common mode failure of onsite emergency AC power or high pressure injection function during the operating period reviewed. During this period, an average of 75 reactors were operating. Thus, the frequency of common mode failure for either system was estimated to be once in 300 RY or 0.0033/RY.

To evaluate the frequency of the cut sets and sequences affected by these common mode failures, it was necessary to estimate the resulting additional system unavailability using the above common mode failure frequency of 0.0033/RY per system.

Two sequences were considered in determining the increased system unavailability. The first sequence considered a potential inadvertent FPS actuation resulting in total loss of either HPI or onsite emergency AC power followed by a 36-hour period when either the HPI or diesel generators are out of service. The 36-hour period was selected based on plant TS considerations assuming that plant personnel are aware that the inadvertent FPS actuation has occurred but are unable to restore operability to the affected system. Plant TS require that, in the event of total inoperability of such systems, the operators must restore operability of at least one train within one hour. If operability cannot be restored, then the plant must be in hot standby in the next 6 hours and in cold

shutdown in the following 24 hours. It was assumed that the plant would be no longer vulnerable to loss of these systems after cold shutdown was achieved.

The second sequence considered a potential plant transient or SBLOCA followed by a 3-day period during which the plant would be vulnerable to an inadvertent FPS actuation which could cause total loss of the diesel generators or the HPI system. The 3-day vulnerability period was assumed on the basis that 3 days are long enough to restore AC power from offsite, depressurize the RCS, and operate in a recirculation mode. Also, after 3 days, reactor decay heat flux is low enough that various auxiliary system small-capacity, low-head pumps could be aligned to keep up with atmospheric boil-off of decay heat in a feed-and-bleed mode, if necessary.

If it were assumed that Sequence 2 was additive to Sequence 1, the total period of plant vulnerability from outage of either system could be 4.5 days. Using 4.5 days, the additional unavailability of either system was estimated to be:

$$\frac{(0.0033/RY)(4.5\ days)}{365\ days/RY} = 4.1 \times 10^{-5}$$

This additional unavailability was then added to each of the parameters associated with core-melt sequences involving loss of onsite emergency AC power or HPI system function. The resulting increase in core-melt frequency was estimated to be 3.4×10^{-7}/RY, of which 55% was associated with diesel generator unavailability and the remaining 45% with HPI system unavailability.

Based on the operating experience used and the derived additional system unavailability, safety system interactions associated with inadvertent FPS actuations represented non-dominant contributors to the overall core-melt risk of a plant.

With regard to spurious FPS actuations interacting with a single train of a safety system, the operating experience in Table 3.57-1 indicated that one train of a given system could have been affected as often as 18 times during the 300 RY operating period reviewed. Thus, a single train interaction frequency as high as 6×10^{-2}/RY can be derived. However, even at this frequency, such occurrences were considered insignificant contributors to total system unavailability since the redundant train would still be available. Also, in all of the single train interactions reported, the affected train was restored to operability within the outage time for a single system train allowed by plant TS.

Consequence Estimate

Because the contribution to core-melt was low, the potential reduction in public risk was not calculated.

Cost Estimate

The minimum cost/plant to comply with an IE Bulletin which required all licensees to reevaluate their implementation of FPS guidelines concerning FPS interactions would involve three-quarters of an engineering staff-year (~$75,000) to conduct the review and submit a report to the NRC. Any resulting changes to plant procedures or FPS hardware would be additional cost and would be unique to each plant. Also, NRC effort to review the response from each plant would average 2

to 3 staff-months/plant or approximately $20,000/plant. Thus, the minimum cost to comply with an IE Bulletin was estimated to be $100,000/plant, exclusive of plant-unique FPS modifications.

Value/Impact Assessment

No priority score was calculated since the frequency and consequence estimates were very low.

Uncertainty

As noted above, approximately 80% of the 30 FPS actuations reviewed were a direct result of personnel error during maintenance and/or testing of the FPS or systems adjacent to FPS detectors. Coupled with the consideration that following a plant transient or LOCA it is very unlikely that plant personnel would be engaged in such work, the likelihood of inadvertent FPS actuations as postulated for the second sequence considered in the frequency analysis above would be low. If only the first sequence of events were considered, the core-melt contribution due to unavailability of onsite emergency AC power or the HPI system would reduce to 1.1×10^{-7}/RY.

Other Considerations

Surry 2 Feedwater Line Rupture: The data base used in the frequency analysis did not include the feedwater line rupture event at Surry 2 on December 9, 1986. During this event, the Cardox and Halon fire suppression systems were actuated by steam/water intrusion into their control panels. The security repeater (located approximately 5 feet from a Cardox discharge nozzle) failed and was later found to be covered with a thick layer of ice. As a result, security communications were limited to the non-repeater hand-held radios. Therefore, the actuation of the Surry FPS resulted in the loss of a single train of a safety system. This was the first such occurrence at the Surry plant in its 14 years of operation and one could calculate a frequency of occurrence of actuation of the FPS resulting in the loss of a single train of a safety system at Surry of 1/14 or 7.1×10^{-2}/RY. The data base used in the analysis of this issue identified 18 events in which actuation of the FPS resulted in the loss of a single train of a safety system. For the 300 RY represented by the data base, the 18 events would result in a frequency of 6×10^{-2}/RY for FPS actuation causing loss of one train of a safety system. It was concluded that the operational history at Surry was in sufficient agreement with the data base used for the above analysis and the significance of the Surry event with regard to the interaction of the FPS with plant safety systems was encompassed within this issue.

CO_2 Releases: During the operating period reviewed, 3 of the 28 releases of fire suppressant were releases of CO_2: 2 were inadvertent and 1 was a planned CO_2 system acceptance test. One event caused evacuation of maintenance personnel from a cable spreading room following the FPS pre-release alarm. In most plants, the cable spreading room is an unmanned area. The second event resulted in sufficient pressure buildup to force open a closed door in an ECCS penetration room. The third event was a planned acceptance test which failed to achieve the specified CO_2 concentration but also caused rapid temperature reduction in a cable spreading room such that some instrument cabinets approached their operating temperature lower limit. In this latter case, the CO_2 system was replaced with a halon gas system. None of these releases resulted in an adverse interaction

with safety systems or a plant transient. The staff's FPS guidelines addressed the possibility of each of the conditions described above.

External Events: An additional consideration concerned a potential external event such as a large smoke cloud due to a large offsite fire, or a seismic event which could cause actuation of multiple smoke detectors which could cause inadvertent release of fire suppressant in several plant areas.

During the operating period reviewed, there was one occurrence of a large external smoke cloud due to a large grass fire near a plant that actuated several smoke detectors. In this instance, no suppressant was released since the smoke detectors were used with pre-action water sprinkler systems which require heat in the vicinity of the sprinkler head to melt the fusible link before releasing suppressant. Also, the operators had advance notice of the approaching smoke cloud and had time to start operation and to have personnel available to establish fire watches in an area where smoke detectors were actuated. For a plant with open head deluge sprinklers, the advance warning would permit time to deactivate the deluge system and post a fire watch in an area where safety equipment might be exposed.

A core-melt frequency of 3×10^{-9}/RY was estimated for large offsite fires causing an inappropriate or inadvertent actuation of the FPS and further failures resulting in core-melt events. The one precursor event mentioned above translated to a frequency estimate of 1.4×10^{-3}/RY for offsite fire-induced FPS actuation. A probability of 0.1 was assumed for failure to post a fire watch and take manual control of the FPS. AFWS failure assumptions were as follows:

Probability that AFWS is protected by an open head deluge system	= 0.02
Probability of AFWS electrical failure due to deluge	= 0.02
Probability of operator error defeating manual operational of AFWS	= 0.10

Failure of feed-and-bleed heat removal was assumed to be 0.5/demand. These estimates and assumptions were used to calculate the 3×10^{-9}/RY core-melt frequency estimate for offsite fire-induced FPS actuation. Thus, the offsite fire contribution to core-melt for this issue was found to be negligible.

The frequency of a core-melt event initiated by a seismic event of OBE magnitude or greater causing an inadvertent actuation of the FPS was estimated to be 10^{-8} /RY. It was believed that there was still some conservativism inherent in this estimate and that a more rigorous development of a best estimate frequency for this sequence of events would result in a lower frequency estimate. The LLNL Report (UCRL-53037), which provided estimates of earthquake frequency at the Zion site and the conditional probabilities of transient or LOCA initiators given an earthquake, was used to develop a frequency of 2×10^{-6}/RY for earthquake-induced LOCA and 5.6×10^{-4}/RY for earthquake-induced loss of offsite power (T_1) transients. Examination of systems and equipment at 109 different major industrial facilities (including power plants) that experienced seismic events (peak ground accelerations from 0.1g to 0.75g) revealed no inadvertent operation of FPS. Therefore, a conditional probability of 10^{-2} was assumed for FPS actuation, given an earthquake. The 30 inadvertent FPS actuation events yielded only one event in which complete loss of safety function (emergency onsite power diesel generators) resulted. Therefore, a conditional probability of loss of safety function given an earthquake was assumed to be 1/30 or 3.3×10^{-2}. This probability was assumed for both a loss of emergency onsite power for T_1

transient events and loss of high pressure injection for LOCA events. Solution of the LOCA and T_1 transient event trees resulted in the 10^{-8}/RY estimated core-melt frequency due to seismic-induced FPS actuations. When compared to the estimated core-melt frequency of 3.4×10^{-7}/RY from other scenarios resulting from inadvertent FPS actuation, the seismic contribution was found to be negligible.

Periodic Fire Protection Program Audits: There already existed a mechanism for mandatory review of the Fire Protection Program and implementing procedures for each plant without requiring an IE Bulletin. The TS for each plant requires under Administrative Controls:

(a) An independent fire protection and loss prevention inspection and audit annually utilizing either qualified offsite licensee personnel or an outside protection firm.
(b) Audit of the Fire Program and implementing procedures at least once every 24 months.
(c) An inspection and audit of the fire protection and loss prevention program by an outside qualified fire consultant at intervals no greater than 3 years.

The issuance of IE Notice 83-41[1025] and periodic INPO Significant Event Reports provide timely operations feedback to enable licensees to consider applicability of such events in the periodic program reviews indicated above. Several plants have documented instances where their periodic reviews in conjunction with the feedback information identified an area where there was potential for FPS interaction with part of a safety system and corrective action was taken.

CONCLUSION

Based solely on the above quantitative analysis, this issue would have been given a low priority ranking (See Appendix C). However, the external events portions of the analysis, although resulting in a low safety significance, had (by their very nature) large uncertainty error bands inherent in the determination of frequencies of occurrence for rare events (i.e., earthquakes). In addition, the analysis of events resulting in core-melt from inadvertent FPS actuation considered the frequencies of initiating events (particularly transients) to be independent of the FPS actuation. Initially, it must be assumed that, if inadvertent FPS actuations can result in the loss of a safety system train or function, in some instances it can also result in the initiation of a reactor transient. This limited analysis could not incorporate such subtle effects of FPS actuation. Hence, it could be assumed that the true core-melt frequency would be greater than that calculated above.

The ACRS and the nuclear industry showed a higher interest in this concern than that which would be normally warranted of a low priority safety issue. In fact, the nuclear industry, through EPRI, initiated a study of the effect of inadvertent FPS actuation on plant safety. The EPRI study was one of three research initiatives suggested by the EEI Fire Protection Committee as a result of their review of electrical utility experience with the design and operation of FPS at both nuclear and non-nuclear electric generation facilities. In consideration of the above factors, this issue was given a medium priority ranking.

In resolving the issue, the staff evaluated 4 plants and found that the dominant risk contributors fell into the following 2 categories: (1) seismic-induced fire plus seismic-induced suppressant diversion; or (2) seismic-induced actuation of the FPS. Both of these categories were to be addressed in the IPEEE.[1222] The staff's technical findings were published in NUREG-1472[1541] and NRC Information Notice 94-12[1543] was issued. An evaluation of the issue was documented in NUREG/CR-5580.[1588] Thus, the issue was RESOLVED with no new requirements.[1542] Consideration of a license renewal period of 20 years would not affect the resolution.

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1222. NRC Letter to All Licensees Holding Operating Licenses and Construction Permits for Nuclear Power Reactor Facilities, "Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR § 50.54(f), (Generic Letter No. 88-20)," November 23, 1988, (Supplement 1) August 29, 1989, (Supplement 2) April 4, 1990, (Supplement 3) July 6, 1990, (Supplement 4) June 28, 1991.

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1543. NRC Information Notice 94-12, "Insights Gained from Resolving Generic Issue 57: Effects of Fire Protection System Actuation on Safety-Related Equipment," February 9, 1994.

1588. NUREG/CR-5580, "Evaluation of Generic Issue 57: Effects of Fire Protection System Actuation on Safety-Related Equipment," (Vol. 1) December 1992, (Vol. 2) December 1992, (Vol. 3) December 1992, (Vol. 4) December 1992, (Vol. 5) December 1992.

ISSUE 73: DETACHED THERMAL SLEEVES

DESCRIPTION

Historical Background

During the period 1978 to 1980, there were reports of fatigue failure of thermal sleeve assemblies in the piping systems of both PWRs and BWRs. The BWR problem was addressed by GE in NEDO-21821 and was resolved with a staff SER[1314] and the publication of NUREG-0619.[742] Fatigue problems occurred subsequently in 1982 in PWRs designed by B&W and W. IE Information Notices No. 82-09[1311] and No. 82-30[1312] were issued by the staff to address the problems at B&W and W reactors, respectively. Status reports on the B&W pipe cracking problem were contained in SECY-82-186[1313] and SECY-82-186A[513] which described the problem of thermal sleeve cracking in the normal make-up/high pressure injection nozzles of four B&W plants. No notable events were reported at PWRs designed by CE.

As a result of the fatigue failures in B&W reactors, a B&W Owners' Group Task Force was established to identify the cause of the failure and to recommend modifications to eliminate future failures. This Task Force submitted a report[514] to the NRC and the concern was resolved in Issue 69, "Make-up Nozzle Cracking in B&W Plants."

The concern regarding thermal sleeves in W-designed plants was raised by the staff[518] following remote video inspections that revealed pieces of metal at the bottom of a W reactor vessel at the Trojan Nuclear Plant; a metal fragment was also found between the lower core plate and the core support plate. All metal pieces were subsequently identified as part of the thermal sleeves initially installed in the safety injection accumulator piping nozzle connections to the reactor coolant system cold leg piping. Confirmation that the 10-inch thermal sleeves were missing from the four safety injection piping nozzle connections was obtained shortly thereafter. In response to the Trojan cracking and detachment of thermal sleeves, a plant-specific review was conducted and an SER[1315] was completed by the staff. In this SER, the staff established the basis for continued operation of the Trojan plant, subject to the findings of a staff generic study on W plants.

There have been five generations (0 through 4) of thermal sleeves used in W reactors. Only "Generation 3" thermal sleeves have been found to be susceptible to high-cycle stresses due to flow-induced vibrations because of the particular weld attachments used in that design. The vibrations caused fatigue failures at the thermal sleeve attachment welds and subsequent cracking and tearing away of the thermal sleeves resulted in the formation of loose parts moving into the reactor vessel. This issue was applicable to the design and operation of approximately 20 W plants that used Generation 3 thermal sleeves.

Safety Significance

The safety significance of loose parts in the vessel was the potential for flow blockage and/or cladding wear or destruction by parts wedged within the fuel assemblies. In addition, if the thermal sleeves become detached at a plant, or

are removed and not replaced, there is an ancillary concern that the nozzle cumulative usage factor may be exceeded during the remaining lifetime of the plant.

Possible Solution

After an evaluation of the thermal sleeve problems at several W plants, the staff concluded[1316] that licensees could elect to either retain the Generation 3 thermal sleeves or remove them. If the decision was to retain the sleeves, licensees would have to develop a program to inspect the attachment welds of these sleeves at each refueling outage. If licensees elected to remove the Generation 3 thermal sleeves, they would have to submit revised TS to monitor the injection flow transients which occur at the affected nozzles and evaluate the cumulative fatigue usage factors.

CONCLUSION

This issue was resolved for BWRs with the publication of NUREG-0619.[742] For B&W reactors, the issue was resolved in Issue 69; no problems were reported at CE reactors. For W reactors, a proposed resolution was identified[1316] and pursued.

In resolving the issue at those plants with W reactors, the staff found that licensee implementation of the measures identified by the staff in 1983 adequately addressed the safety concern. With the exception of two plants, all affected plants had made commitments to implement the staff's resolution. The staff's technical findings were documented in NUREG/CR-6010.[1445] Thus, this issue was RESOLVED and requirements were established.[1446] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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ISSUE 76: INSTRUMENTATION AND CONTROL POWER INTERACTIONS

DESCRIPTION

Historical Background

This issue was identified[524] when a number of concerns regarding DC power systems were raised during the review of the proposed resolution of Issue A-30, "Adequacy of Safety-Related DC Power Supplies." The main concerns were:

(1) An instrumentation and control (I&C) power supply fault can cause a critical challenge to standby ESFs, i.e., cases including reactor trips, loss of main feedwater, loss of offsite power, and/or small LOCA through a failed-open PORV.

(2) The same I&C power supply fault could defeat some of the ESFs called upon to mitigate the initiating event, both core cooling systems and containment cooling systems.

(3) The same I&C power supply fault could blind or partially blind the operators to the status of the plant.

I&C electric power systems include AC and DC systems which provide control and motive power to several vital and non-vital components. These components include instrumentation and controls, emergency diesel generator controls, solenoid valves, and breaker controls. Many of these components are required to operate under abnormal and accident conditions. Large-capacity batteries are a typical electric power system component which provide electric power to the DC components. Battery chargers are provided to ensure that an adequate charge is maintained. Inverters are used to convert the DC to AC in order to provide continuous power to vital equipment during offsite AC power interruptions.

Operating experience[1428] indicated that failures in I&C systems have occurred at a significant frequency and a number of these failures have had potential safety implications. Potentially significant events included loss of DC power supplies for one hour, partial and total losses of normal and emergency AC power, loss of control room annunciators, control system malfunctions, reduction or loss of feedwater, and a variety of inadvertent valve actuations. The impact of these failures has ranged from minimal effects on plant operation to reactor trips with complications. Most notable was the event at Nine Mile Point in August 1991.[1429] The simultaneous loss of five uninterruptible power sources was unexpected and presented unique challenges to both equipment and personnel. Fixes that have been implemented to prevent recurrence of these events include modifications to operating procedures, TS changes, and repair or replacement of failed components. The evaluation of this issue included consideration of Issue 46, "Loss of 125 Volt DC Bus."

Safety Significance

The operating events that have occurred were typically recoverable in a short period of time. However, the effects of the power failures may result in

transients involving a series of multiple, propagating interactions that may lead to adverse conditions that are not readily reversible or correctable. This issue affected all operating and future plants.

Possible Solutions

Resolving this issue could require actions to increase the reliability of power systems. One method would be to require additional sources and divisions of electric power which would involve a major hardware modification for some plants. For example, some plants were already equipped with four divisions of vital AC and DC power. Other possible solutions could include new testing, increase existing test frequencies, improve preventive maintenance and/or better operating procedures.

PRIORITY DETERMINATION

This issue affected 90 PWRs and 44 BWRs with average remaining lives of 28.8 and 27.4 years, respectively. This analysis was performed for Grand Gulf 1 (BWR) and scaled to Oconee 3 (PWR) using the scaling relationships given in NUREG/CR-2800.[64] The primary focus of the analysis was on DC power systems. Two situations involving DC power losses were analyzed separately and the results combined; one involved DC power failures as initiating events and the other involved DC power failures as contributing events.

Assumptions

The Grand Gulf 1 PRA includes DC power system failure as a contributing event. The analysis of this issue required added assumptions about DC power system failures as initiating events.

It was assumed that undervoltage and undercurrent events can have the same consequences as a sudden loss of power. This assumption was supported by LER data reviewed from the 1984 to 1990 time period which involved DC system failure. For example, an undervoltage can result in a main feedwater trip. The transient and resultant reactor trip are similar to a sudden loss of main feedwater. In analyzing the LER data, the undervoltage and undercurrent events were assumed to be failures of the affected equipment.

It was assumed that overvoltage and overcurrent events are recoverable because of the protective devices on the equipment. Unless the protective devices fail, the equipment will not be damaged and can be returned to service (if lost); the LER data from 1984 to 1990 supported this assumption.

The frequency of DC power system failures, using the above assumptions and the data from the LERs, was the basis for improving the adjusted case. The possible solution was assumed to increase the reliability of DC power systems, based on battery failure rate distributions given in the Nuclear Computerized Library for Assessing Reactor Reliability (NUCLARR).[1327] The error factors given in NUCLARR for 7 battery failure rate data points ranged from 2 to about 8. The average of these data points was 4.76. The solution was conservatively estimated to reduce the frequency of battery failures by a factor of 3.[1327]

Using a station blackout analysis, an event tree was constructed with the loss of DC power as the initiating event. The loss of AC power was assumed to be

independent of a loss of the DC power system. The emergency AC power reliability was assumed to be representative of a single, failed diesel in a two-diesel generator system; the probability of recovery of AC power within one hour was estimated to be 0.55.[890]

If AC power is available, it was assumed that RCP seal cooling is available and an RCP seal LOCA is not likely to occur. However, the subsequent transient is likely to result in an increase in primary coolant system pressure and temperature. The potential exists for a LOCA to be caused by a stuck-open safety relief valve. The AC power recovery time to prevent core damage from a stuck-open relief valve is 1 to 2 hours. If AC power is not available, there is a significant probability that a RCP seal LOCA will occur. The AC power recovery time to prevent core damage from a RCP seal LOCA depends on the size of the LOCA. If RCP seal leakage is large (more than 100 gpm/pump), the core could be uncovered within a few hours. Smaller leak rates (a few gpm/pump) are not a limiting factor.[890] Issue 23, "Reactor Coolant Pump Seal Failures," showed a probability of leak rates of 480 gpm/pump, which would reduce the recovery time significantly.

Frequency Estimate

DC Power Failure - Initiating Events: To estimate the reduction in core-melt frequency, a search of LERs from 1984 through 1990 was made using the key words "DC power" and "station battery." Only those LERs that had safety significance were considered. From this LER data, the base case value for the frequency of DC power failures and subsequent reactor trip as an initiating event was estimated to be 0.06/RY. Based on the Grand Gulf 1 PRA, the frequency of this initiating event leading to core-melt was calculated to be 6×10^{-7}/RY. The adjusted case was then calculated based on a factor of 3 reduction in initiating event frequency, resulting in a core-melt frequency of 2×10^{-7}/RY.

DC Power Failure - Contributing Events: DC power system failures as contributing events are represented in the Grand Gulf 1 PRA by events BATA and BATB. The base case failure probabilities for both these events are 0.001. The base case CDF for Grand Gulf was 4.9×10^{-7}/RY and the adjusted case was calculated to be 1.6×10^{-7}/RY, based on a factor of 3 improvement in the unreliability of the batteries and DC system. Combining these 2 sets of events resulted in a base case core-melt frequency of 1.1×10^{-6}/RY and an adjusted case core-melt frequency of 3.6×10^{-7}/RY. Subtracting the adjusted case from the base case yielded a reduction in core-melt frequency of 7.4×10^{-7}/RY for BWRs.

The PWR values of core-melt frequency were arrived at by scaling the BWR values; this resulted in an estimated base case core-melt frequency of 2.4×10^{-6}/RY and an adjusted core-melt frequency of 8×10^{-7}/RY. The reduction in core-melt frequency then is 1.6×10^{-6}/RY for the PWR.

Consequence Estimate

For BWRs, the core-melt frequency reduction of 7.4×10^{-7}/RY translated to a public risk reduction of 2.1 man-rem/RY. For 44 BWRs with an average remaining life of 27.4 years, the estimated public risk reduction was 2,532 man-rem. For PWRs, the core-melt frequency reduction of 1.6×10^{-6}/RY translated to a public risk reduction of 1.7 man-rem/RY. For 90 PWRs with an average remaining life of 28.8 years, the estimated public risk reduction was 4,406 man-rem. Thus, the

total potential public risk reduction associated with this issue was approximately 7,000 man-rem.

Cost Estimate

Industry Cost: All plants would need to prepare a FMEA of their power systems and would have to: (1) revise TS; (2) rewrite operating procedures; and (3) train operators. At a cost of $99,000/plant, the cost for these changes were estimated to be $13.3M. In addition, it was estimated that 27 plants with particularly unreliable DC power systems would require hardware modifications. These plant modifications were estimated to cost $275,000/plant for a total of $7.4M.

The TS changes were assumed to increase the power inspection/tests. The annual cost necessary for operating and maintaining the proposed solution was assumed to include approximately 48 man-hours/RY. This estimate included periodic retraining as well as additional time required to perform more surveillance tests on the batteries. This estimated annual cost was $2,724/RY. For all 134 plants with an average remaining life of 28.3 years, the cost was $10.3M.

NRC Cost: One man-year of contractor effort was estimated for reviewing and updating existing data, determining the feasibility of the possible solution, and developing a technical findings document. NRC technical oversight was estimated at 0.1 man-year. A value/impact and backfit analysis was estimated at $75,000. At a cost of $100,000/man-year, the total development costs were estimated at $0.185M.

NRC review of the FMEA and TS revisions was estimated at 0.5 man-week/plant. At a cost of $2,270/man-week, the total estimated cost was $0.15M for all 134 plants. Reviewing the hardware modifications was estimated to require 2 man-weeks/plant. Since hardware modifications would be required only on the 27 plants with unreliable DC power systems, at a cost of $2,270/man-week, these reviews would cost $0.123M. The total NRC cost to support implementation was estimated to be $0.273M.

The NRC support cost for operation and maintenance for plants requiring hardware modifications was estimated at 0.5 man-week/RY. Since the 27 plants had an estimated remaining life of 28.3 years, the total NRC operation and maintenance support cost was estimated to be $0.867M.

Total Cost: The total industry and NRC cost associated with the possible solution to this issue was $32.3M.

Value/Impact Assessment

Based on an estimated public risk reduction of 7,000 man-rem and a resolution cost of $32.2M, the value/impact score was given by:

$$S = \frac{7{,}000 \text{ man-rem}}{\$32.3M}$$

$$= 217 \text{ man-rem/\$M}$$

Other Considerations

Additional Public Risk Attributed to Vital AC Power Losses: The reduction in core-melt frequency and resultant risk was estimated while focusing on the DC portion of the issue. Inclusion of the vital AC portion would tend to raise the risk reduction and therefore the issue priority.

Other Related Actions: Issue 128, "Electrical Power Reliability," combined a number of electrical power issues and considered a number of related issues and actions. Three specific issues were A-30, "Adequacy of Safety-Related DC Power Supplies"; 48, "LCOs for Class 1E Vital Instrument Buses"; and 49, "Interlocks and LCOs for Class 1E Tie Breakers." With the resolution of Issue 128 and other issues, a number of actions were taken that could have a significant impact (i.e., lower the assumed safety benefit) on the possible resolution of Issue 76 and, therefore, lower its priority.

IPE: One preliminary result[1430] from a plant IPE indicated that certain power system faults/failures can be a large contributor to a core-melt. In this instance, the unbalanced nature of the loads contributed to the significance of the postulated events. This would tend to increase the priority of the issue.

Life Extension: The remaining life of the affected plants was based on the assumption that the total operating life of nuclear power plants was limited to 40 years. If it was assumed that 75% of the plants had their licenses extended for 20 years, the value/impact score would have increased to about 260 man-rem/$M.

CONCLUSION

The preliminary results[1430] from an IPE indicated that certain power system faults/failures can be a large contributor to core-melt probability. Although the potential risk reduction calculated above would have placed this issue in the medium priority category (See Appendix C), it was concluded that the safety concern would be addressed more directly on a plant-specific basis in the IPE program. Therefore, this issue was DROPPED from further pursuit as a new and separate issue. Consideration of a 20-year license renewal period did not change this priority.[1564]

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ISSUE 78: MONITORING OF FATIGUE TRANSIENT LIMITS FOR REACTOR COOLANT SYSTEM

DESCRIPTION

Historical Background

STS for newer OLs require licensees to keep account of the number of transient occurrences to ensure that transient limits, based on design assumptions, are not exceeded. However, a number of older plants for which detailed fatigue analyses were performed on ASME Section III, Code Class 1 (reactor coolant pressure boundary) components did not have TS requirements for monitoring actual transient occurrences. These transients could significantly affect the fatigue life of the RCS. This issue originated as MPA B-70, but a letter to licensees was never issued for the collection of information.[528, 529]

Safety Significance

Repeated thermal cycling of RCS components produces some degree of fatigue degradation of the component materials which could lead to failure, thereby increasing the likelihood of a LOCA.

Possible Solution

A possible solution was to require the affected plants to implement TS to monitor plant transients and to verify that the design life of all ASME Section III, Code Class 1 components have not been exceeded. Plants that had experienced transient events that exceeded design limits may find it necessary to perform fatigue analyses to determine the number of remaining thermal cycles before fatigue limits are exceeded.

PRIORITY DETERMINATION

Assumptions

The reference plants selected for this analysis were Oconee 3 for PWRs and Grand Gulf 1 for BWRs. It was estimated[64] that 30 PWRs, with an average remaining operating life of 27.7 years, and 16 BWRs, with an average operating life of 25.2 years, were affected by this issue. These estimates were based on the original 40-year operating license.

Frequency Estimate

The affected parameters in the Grand Gulf 1 and Oconee 3 PRAs were determined to be the LOCA-initiating event frequencies.[64] The original values of these parameters are shown below:

Oconee 3

S_1 : Large LOCA = 1.0×10^{-4}/RY
S_2 : Medium LOCA = 4.0×10^{-4}/RY
S_3 : Small LOCA = 1.3×10^{-3}/RY

Grand Gulf 1

S : LOCA = 1.4×10^{-3}/RY

The values for these parameters were developed assuming that the fatigue life for RCS components were as designed. Potential events such as overcooling or transients that may result in RCS cooldown rates in excess of limits that could reduce the design life of RCS components were not taken into account. Therefore, these values also represented the adjusted case values of affected parameters as they were derived assuming: (1) the design limits would not be exceeded; and (2) the number of allowable thermal cycles was the same as that used in the design. These values also represented plant conditions representative of the improvement they would achieve through resolution of the issue.

The base case values of the affected parameters were developed in consideration of the actual fatigue degradation that may be experienced by RCS components. The degradation had been shown to reduce the lifetime of RCS components which, in turn, will increase the frequency of RCS piping failures. This increase in frequency was assumed to be inversely proportional to the reduction in the number of allowable cooldown cycles with respect to the as-designed number of cycles that a plant may experience.

A fatigue analysis was performed in support of the restart of the Rancho Seco nuclear power plant[1366] after several transients were experienced during which the normal cooldown rate was exceeded. This analysis examined the limiting fatigue usage factors in the reactor coolant piping, pressurizer, CRD mechanisms, and the RCP casings. It was concluded that the allowable number of cooldowns should be reduced from 240 to 235. Taking the remaining plant life into consideration, it was estimated that Rancho Seco could experience an additional 2 transients during which the normal rate would be exceeded up through the midpoint of remaining lifetime. This would further reduce the number of cooldowns from 235 to 233 and represented an overall reduction of about 3% of the number of allowable cooldowns. The inverse ratio, which represents the reduction in the frequency of RCS pipe breaks, is a factor 1.03. This factor was multiplied by the adjusted case values given above to estimate the base case values of the affected parameters. These values are shown below:

Oconee 3		Grand Gulf 1	
S_1 : Large LOCA =	1.05×10^{-4}/RY	S : LOCA =	1.47×10^{-3}/RY
S_2 : Medium LOCA =	4.20×10^{-4}/RY		
S_3 : Small LOCA =	1.37×10^{-3}/RY		

The probability of reactor vessel failure as a result of thermal cycle fatigue was not included in the base case or adjusted case values because it was believed that the frequency of reactor vessel failure was so small relative to the frequencies of LOCA sequences that it would be insignificant. This conclusion was supported by: (1) data in WASH-1400[16]; (2) the fact that it was not examined in the Rancho Seco restart; and (3) the resolution of Issue 79. Using the affected accident sequences, i.e., all minimum cut sets initiated by LOCAs, and the base case and adjusted case LOCA frequencies developed above, the potential reduction in core-melt frequency was estimated to be 6.3×10^{-7}/RY for PWRs and 10^{-7}/RY for BWRs.

Consequence Estimate

The potential risk reduction from the possible solution was estimated to be 1.26 man-rem/RY for PWRs and 0.72 man-rem/RY for BWRs. When applied to the affected

population of 30 PWRs and 16 BWRs over their estimated remaining lives, a total potential public risk reduction of 1,300 man-rem was estimated.

Cost Estimate

Industry Cost: Implementation of the possible solution would require preparation of an initial report, TS development, and performance of fatigue analyses, as appropriate. For the 46 affected plants, the total implementation cost was estimated[64] to be $4.6M. Operation and maintenance of the possible solution would involve weekly monitoring of fatigue transient limits, estimated[64] to cost $910,000.

NRC Cost: Development of a solution was estimated to cost $91,000, including development of a model TS and preparation of a letter to licensees. Support for implementation of the solution was estimated to cost $630,000, including review and approval of license amendments and TS and the preparation of safety evaluations. Support for operation and maintenance associated with the possible solution was estimated to cost $910,000, resulting in an overall total NRC cost of $1.6M.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $7.1M.

Value/Impact Assessment

Based on an estimated public risk reduction of 1300 man-rem and a cost of $7.1M associated with the possible solution, the value/impact score was given by:

$$S = \frac{1{,}300 \text{ man-rem}}{\$7.1M}$$

$$= 188 \text{ man-rem/\$M}$$

Other Considerations

(1) The assumed solution, consistent with the narrowly specified scope for this issue, involved only the monitoring and reporting requirements and, perhaps, evaluations of thermal cycle fatigue limits against the original licensing basis ASME Code criteria. No work in radiation zones would be required for implementation, operation, or maintenance of the possible solution.

(2) Assuming that the affected plants will have their licenses extended for an additional 20 years and that these plants would be operational 75% of this time, the average remaining operating life would be 42.7 years for PWRs and 40.2 years for BWRs. The possible risk reduction, including overcooling events for this extended period, would be 2,790 man-rem. The total industry cost for implementation, operation, and maintenance of the possible solution would be $6M; the NRC cost over this same period would be $2.1M. Thus, the total industry and NRC cost would be $8.1M. The value/impact score for life extension would be 344 man-rem/$M.

(3) In June 10, 1992, NRR requested[1452] that the issue be expanded to include those early vintage plants whose RCS components were not designed to ASME

Section III and did not receive a fatigue analysis. Expansion of the scope of this issue to include recognition that many early vintage RCS components were not specifically evaluated for fatigue effects would result in an increased, though unquantified, probability of failure and also would increase the uncertainty of the failure probability.

(4) The staff expressed concerns regarding the adequacy of the fatigue curves used in ASME Section III in taking into account environmental effects. At the time of the initial evaluation of this issue in July 1992, data indicated that existing Code fatigue curves may have had less margin than that originally intended when considering the effects of fatigue induced by the operating environment. The net result of the reduced conservatism in the fatigue design curves in ASME Section III could be an increased probability of component (including reactor vessel) failure by an unquantified amount.

Taking the above considerations into account would tend to increase the priority ranking of the issue.

CONCLUSION

Based on the potential public risk reduction and the uncertainties discussed above, the issue was given a MEDIUM priority ranking (See Appendix C). This issue will provide technical information for the resolution of Issue 166 and, therefore, will not require separate consideration of a 20-year license renewal period.[1564]

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ISSUE 79: UNANALYZED REACTOR VESSEL THERMAL STRESS DURING NATURAL CONVECTION COOLDOWN

DESCRIPTION

Historical Background

On March 18, 1983, B&W expressed[530] concern for unanalyzed reactor vessel thermal stress that could occur during natural convection cooldown of PWRs. The concern emerged from a preliminary B&W evaluation of a voiding event that occurred in the upper head of the St. Lucie reactor on June 11, 1980. Based upon several conservative assumptions, B&W tentatively concluded that, during natural convection cooling, axial temperature gradients between 150°F and 200°F could develop in the vessel flange area which could produce thermal stresses in the flange area or in the studs that might exceed Code allowables, when added to the stresses already considered (bolt-up loads, pressure loads, etc.). B&W acknowledged the preliminary nature of their analysis and noted that, if their conservatively calculated cooling rate of the stagnant coolant in the vessel head (2°F/hour) were in the range of 20°F/hour, then the estimated vessel stresses would not be excessive.

B&W requested assistance from the NRC in obtaining any data or information which might help in the technical evaluation of this problem, but noted that this phenomenon was not likely to be a serious near-term safety concern. However, it was their view that it did represent an unanalyzed situation with the potential for margin reduction over the life of a plant. Preliminary evaluations[531,533] by the NRC staff also led to the conclusion that the problem was not a serious near-term safety concern, although a Board Notification[534] was issued.

In an RES memorandum[668] to NRR, it was pointed out that the closure flange regions of reactor vessels were of concern in drafting revisions to Appendices G and H of 10 CFR 50; these regions control the pressure-temperature limits at low pressures for vessels that have very little radiation damage in the beltline region. Critical flaw sizes are of the order of 0.25 inch deep. The existence of a possible new source of stress in the flange region could have a bearing on the revisions to 10 CFR 50. An additional analysis of the concern was made by the B&W Owners' Group.[669]

Safety Significance

When unanalyzed reactor vessel thermal stress is added to existing stresses, the stresses in the flange area or studs could exceed the allowable stress. Moreover, the cycling of these temperature gradients could cause a reduction in the fatigue margin or usage factor of the vessel over the life of a plant. In addition, depending upon the vessel temperature distribution, there is a possibility of vessel fracture under these circumstances. These factors could cause vessel cracking that could lead to unacceptable vessel failure during the life of the vessel. However, it was assumed in this analysis that sufficient water is available to prevent dry-out of the steam generators; otherwise, the consequences could be more serious than estimated.

Possible Solution

If unanalyzed thermal stresses cause a reduction of fatigue life or lead to reactor vessel stresses that exceed the allowable stresses for the vessel, the solution was assumed to be a slower cooldown rate than the existing allowable rate of 100°F/hour.

PRIORITY DETERMINATION

Frequency Estimate

In an effort to establish the frequency of the occurrence of unanalyzed stress, it was noted in the B&W letter[530] that "[t]hese non-uniform effects in the reactor coolant may occur once the reactor coolant pumps are secured and the decay heat removal system has been actuated in the normal cooldown mode or during natural circulation." This B&W statement was somewhat of an oversimplification, however, and may have been misleading since the effects resulting from normal cooldown and natural circulation cooldown could be substantially different with regard to the non-uniform effects in question. (In the normal cooldown mode, the RCPs continue to operate until the reactor and temperature are reduced to the cut-on levels for the decay heat removal system pumps which are well below the values at which natural circulation would be initiated, if required.) Therefore, with the RCPs running during the early phase of a normal cooldown, it would be expected that significant mixing of the fluid in the reactor head would occur in this period of the cooldown so that the non-uniform effects are likely to be minimized, if not precluded. On the other hand, the natural convection mode of cooldown would tend to have larger non-uniform effects because it starts with the highest fluid and material temperatures and the thermal mixing is assumed to be substantially lower than with the RCPs in operation. Therefore, the frequency corresponding to this cooldown mode was used in this analysis.

A dominant factor that could affect primary coolant pump availability leading to the need for natural convection cooling is the loss of offsite power, because the large power demand of these pumps usually exceeds the on-site power supply capability. It was noted, however, that Regulatory Guide 1.93[532] provides guidance that permits continued operation of a plant for up to 24 hours after loss of offsite power followed by 6 hours of hot standby, if this implements the safest operating mode whenever the offsite power sources are less than the limiting conditions of operation. For this time period (30 hours), it was estimated from the information provided in NUREG/CR-3226[526] that the probability of not recovering offsite power was approximately 0.03. If offsite power did not return in this time, a plant is brought to cold shutdown and natural convection cooling would follow. However, the licensee need not keep the plant up for 30 hours and can elect to immediately bring the plant to the cold shutdown state if it is deemed the safest mode of operation following the loss of offsite power. In this case, natural convection cooling of the reactor would begin promptly and it was estimated from NSSS vendor studies[535,536] that the maximum thermal gradients in the reactor vessel would occur in approximately 2 to 3 hours. From the information in NUREG/CR-3226,[526] it was estimated that the probability of not restoring offsite electric power within two hours was approximately 0.35. Inasmuch as this latter case represented the more stringent conditions for this issue, this analysis was based on immediate shutdown to the cold shutdown condition as a conservative scenario.

The frequency of the loss of offsite power was established as 0.118/RY[526] and the probability of not restoring offsite power within 2 to 8 hours was about 0.35. The frequency of attaining the maximum thermal gradients within the reactor, as a result of natural convection cooling, was estimated to be (0.118)(0.35)/year or 0.04/year.

Consequence Estimate

Following the loss of the primary pumps, the reactor will be scrammed, natural convection cooling will commence, and the core and reactor vessel will begin to cool down. It was assumed that on-site AC power is available, otherwise the issue would become station blackout (which was addressed in Issue A-44).[526] Based on the cooling rate of approximately 100°F/hour, it was expected that the large temperature gradients described by B&W[530] would begin to develop after approximately 2 to 3 hours, because the vessel head cools down very slowly (~2°F/hour). Since the thermal stress is likely to be greatest in the region from just below the vessel flange[530] to the "knuckle" just above the vessel head flange,[535] a crack was postulated to occur in the upper part of the vessel or vessel head, if the allowable stress were exceeded following the addition of the thermal stress. As a result, the postulated crack was located above the core region.

Upon development of the crack in the upper part of the reactor vessel, the reactor system will blow down as in a LOCA and the core is likely to become partially or totally uncovered. At this time, 2 to 3 hours after reactor shutdown when the large thermal gradients develop, the decay heat is in the order of 1.5% of full power. The time required for the core to slump under these conditions was estimated to be slightly over 1 hour for a 3500 MWt reactor with a core of approximately 1100 ft^3 and a total core heat capacity of 54 $BTU/ft^3/°F$. Within this time period, it is expected that the operator can properly assess the situation and will take appropriate action to prevent core slumping by releasing the water in the accumulators and submerging the core. The integrity of the reactor vessel is expected to be maintained to a level above the height of the core because the high stress regions were limited to the vicinity of the vessel flanges. Boil-off will continue, but it was assumed that water replacement from the reactor plant systems will be available to continue to cool the core. Some gap activity release is possible during the period of postulated core uncovery.

The above scenario is comparable to PWR Release Category 8 or 9[16]; in these categories, the core does not melt and only some of the activity in the gaps of the fuel rods is released. However, in PWR Release Category 8, it was postulated that the containment fails to isolate properly and the public dose was estimated to be 75,000 man-rem. In Release Category 9, the containment isolates properly and the public dose is only 120 man-rem, which can be neglected. Inasmuch as there is no assurance that the containment will isolate properly for this issue, despite the fact that the accident is estimated to occur 2 to 3 hours after plant shutdown, it was assumed that Release Category 8 represented the scenario of this problem. A public dose of 75,000 man-rem was therefore postulated.

From NUREG/CR-2800,[64] the probability that the containment fails to isolate is 0.0073. Therefore, the potential risk reduction was estimated to be (0.04)(0.0073)(75,000) man-rem/RY or 22.6 man-rem/RY. For an average plant lifetime of 28 years, the total risk reduction was estimated to be (22.6)(28) man-rem/reactor or 633 man-rem/reactor.

Cost Estimate

The possible solution to this issue required that natural convection cooling proceed at a slower rate than the allowable rate of about 100°F/hour. It was assumed that the thermal stress condition would be ameliorated if the cooldown time were increased from approximately 80 to 160 hours. Moreover, it was assumed that sufficient water is available to prevent dry-out of the steam generators for these time periods. The increase in cooling time represented down-time for the reactor of an additional 80 hours or 3 1/3 days. At a cost of $300,000/day, the additional licensee cost for each natural convection cooldown was approximately $1M. It was estimated that 2 to 3 natural convection cooldowns would be required over the remaining life of the affected plants, based on the expected frequency of 0.118/RY for the loss of offsite power. The estimated licensee cost associated with three natural convection cooldown events was ($1M)(3)/reactor or $3M/reactor.

Additional NRC and licensee costs associated with technical studies to be performed for the determination of required cooldown rates, possible TS changes, etc., were estimated to be approximately $100,000/plant. Thus, the total cost associated with the possible solution to this issue was estimated to be $3.1M/reactor.

Value/Impact Assessment

Based on the potential risk reduction of 633 man-rem/reactor and a cost of $3.1M/reactor for the possible solution, the value/impact score was given by:

$$S = \frac{633 \text{ man-rem/reactor}}{\$3.1\text{M/reactor}}$$

$$= 204 \text{ man-rem/\$M}$$

CONCLUSION

Based on the value/impact score and the potential risk reduction, this issue was given a medium priority ranking (See Appendix C). However, these results were based on the assumption that sufficient cooling water is available to prevent dry-out of the steam generators without offsite power. Without this assumption, the consequences would be considerably more serious than estimated above.

In resolving the issue, a detailed stress evaluation of the closure region of the 177 Fuel Assembly reactor vessel was performed by B&W for the natural circulation cooldown condition and submitted to the NRC; this fuel assembly design was utilized on all operating reactors. An independent confirmatory stress analysis of the closure was performed by BNL. Based on the results of the BNL review and analyses and an RES staff evaluation of the adequacy of the RV closure region fracture toughness for the natural circulation cooldown condition, RES concluded that the B&W 177 closure region met all existing applicable regulatory design criteria. RES additionally concluded that, except for the issuance of Generic Letter 92-02[1431] for information, no immediate generic or plant-specific actions were necessary. Thus, this issue was RESOLVED and no new requirements were established.[1432] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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669. Letter to P. Kadambi (NRC) from F. Miller (B&W Owners Group Analysis Committee), "Transmittal of RV Head Stress Evaluation Program Results," October 15, 1984.

1431. NRC Letter to All Holders of Operating Licenses or Construction Permits for Pressurized Water Reactors (PWRs), "Resolution of Generic Issue 79, 'Unanalyzed Reactor Vessel (PWR) Thermal Stress During Natural Convection Cooldown,' (Generic Letter 92-02)," March 6,1992.

1432. Memorandum for J. Taylor from E. Beckjord, "Resolution of Generic Issue 79, 'Unanalyzed Reactor Vessel (PWR) Thermal Stress During Natural Convection Cooldown,'" May 4, 1992.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 81: IMPACT OF LOCKED DOORS AND BARRIERS ON PLANT AND PERSONNEL SAFETY

DESCRIPTION

Historical Background

In October 1982, the EDO appointed the Committee to Review Safety Requirements at Power Reactors (CRSRPR) to review NRC security requirements at nuclear power plants with a view toward evaluating the impact of these requirements on operational safety. Overall, the CRSRPR did not identify any clear operational safety problems associated with implementation of the NRC's security requirements. However, the Committee found that there was the potential for security measures at a site to adversely affect safety and issued its recommendations in a report[621] to NMSS on February 28, 1983. In view of one of the findings in this report, a DL/NRR memorandum[542] was issued on May 31, 1983, identifying this issue and suggesting that a multi-disciplinary group be convened to perform an integrated assessment of the potential safety problem associated with locked doors and barriers, with DHFS/NRR in the lead coordinating role. Based on the responses to the memorandum, DL reported[623] that a consensus supported the creation of the multi-disciplinary group to gather the necessary information and prepare a scope of the issue for appropriate consideration. This approach was approved[624] and a DL memorandum[625] to DHFS formally initiated action on this matter.

The multi-disciplinary group held its first meeting on February 28, 1984, and issued a report on June 8, 1984.[626] Inasmuch as a proposed rule (SECY-83-311)[627] specifically designed to address the security barrier issue had been prepared independently and IE Information Notice No. 83-36[628] also had been issued, the work of the group was limited to non-security barriers.

The proposed rule[1436] was eventually adopted and stated that "the NRC is amending its regulations to provide a more safety conscious safeguards system while maintaining current levels of protection." Regulatory changes included: (1) permitting suspension of security based upon 10 CFR 50.54(x) and (y); (2) requiring the access authorization system to be designed to accommodate the potential need for rapid ingress and egress of individuals during emergency conditions or situations that could lead to emergency conditions; and (3) ensuring prompt access to vital equipment by periodically reviewing physical security plans for potential impact on plant and personnel safety. The rule was implemented with Regulatory Guide 5.65[1438] and Generic Letter 87-08[1437] which addressed the issuance of vital area keys to operations personnel. At the time of this evaluation, NRR (Reactor Safeguards Branch) indicated that almost all licensees were in compliance with Regulatory Guide 5.65[1438] and Generic Letter 87-08[1437] and had implemented mechanical key overrides for electronically controlled access doors. The rulemaking resulted in security plan amendments which increased the focus on plant and personnel safety.

Subsequent to the above work, a main feedwater pipe rupture event at the Surry plant (see Issue 139, "Thinning of Carbon Steel Piping in LWRs") caused the failure of a security card-reader which was located approximately 50 feet from the break point. This failure was caused by intrusion of water and steam that

saturated the card-reader. As a result, key cards could not be used to open plant doors. The control room doors were opened to provide access to the control room and security personnel were assigned to the control room to provide access security. One operator was temporarily trapped in a stairway due to the card-reader failure. Electric override switches were later installed to remedy this problem. Because of the failure of the security card-reader during the Surry event, the staff determined that Issue 81 should be expanded to include potential electric door lock failures and reevaluated to determine whether the previous priority ranking (DROP) should be changed.[1163]

Safety Significance

The possible failure of locked doors and barriers that may be required for fire protection, radiation protection, flood protection, and administrative controls is of special concern during abnormal or accident situations when emergency conditions may require prompt and unlimited access of the plant operators to safety equipment in order to assure proper plant shutdown. This issue was applicable to all operating and future plants.

Possible Solution

An evaluation of each plant's locked doors and barriers might be required and appropriate procedural and hardware changes may have to be made to establish that operator access is unimpeded during emergency, abnormal, or accident conditions, and that prompt operator action, as required, is possible.

PRIORITY DETERMINATION

In the event of an accident, failure of the electronic card-reader access control system (ACS) could result in an impediment to operator actions outside of the control room that are required for recovery. Some examples of possible operator actions are: (1) locally overriding a failed component; (2) replacing or repairing a failed component; or (3) realigning valves to bypass a failed pump or clogged pipe. If the card-reader ACS fails, the operator will be impeded in his access through the door.

Even if the ACS fails, there is a large probability that the plant will have a mechanical key override, or that the locks will fail open. The study conducted by the CRSRPR estimated that a majority of plants did not have problems with ACS computer failure, either because the doors fail open, mechanical key overrides are available, or the number of controlled areas is small.[621] An NRR review of plant safeguards revealed that only one plant that did not have a mechanical key override on ACS-controlled doors had locks that failed open. Based upon these data, a probability of 0.01 was assumed to account for the occurrence of no key override, due to lost or misplaced keys, mechanical failure of the override, or failure of an electronic ACS to fail open if so designed.

Assuming the worst case (i.e., the operator has no other means than to defeat the lock), the effect of impeded operator action was estimated, assuming that action begins soon after the accident is initiated. The amount of time between accident initiation and the initiation of core damage was calculated for critical minimum cutsets in WASH-1400.[16] Studies have also been performed to estimate the amount of time required to defeat a locked door, such as the Access Delay Technology Transfer Manual (SNL report SAND87-1926/1 VC-525, June 7, 1989). These studies

showed that the lock on a typical access door in a commercial nuclear power plant could be defeated in less than 6 minutes with hand tools. The number of doors which would be required to be unlocked can also be estimated. The CRSRPR study found that, on the average, operators need to access three doors to perform routine surveillance, starting from the control room.[621] Routine surveillance requires accessing most areas of the plant, as opposed to the type of specific access that would be required for operator actions in response to equipment failure. Therefore, assuming that three doors will need to be accessed is probably a conservative assumption, even for plants which require more than three controlled doors to be accessed for routine maintenance.

Based upon the typical door construction at nuclear power plants, as provided in the SNL report, the time for penetration of a door with hand tools (e.g., a large screwdriver or crowbar) was determined to range from no delay to 6 minutes. The maximum time required to obtain tools, starting from the control room, was estimated to be 5 minutes. These estimates yield a minimum (5 minutes) and maximum (23 minutes) time for breaking through three doors. These times were arbitrarily assumed to be the 10% and 90% points on a success probability curve, with linear interpolation between these points and the probabilities of 0% chance of success at time=0 minutes and 99% chance of success at time=1 hour. Using this curve, the probability of successful performance for a given period of time to core damage can be estimated. This curve was used only to estimate the probability that three locked doors can be defeated before core damage is initiated for any given accident sequence, given the unknown construction of locked doors in the average plant, and the unknown availability of tools. For this evaluation, every sequence that results in damage in greater than one hour was assumed to result in core damage after one hour. This was a conservative assumption since almost every sequence requires more than one hour until initiation of core damage and/or containment failure. A detailed analysis of each accident scenario would be required to determine at what point a given action would become futile.

In order to estimate the probability that the card-reader will fail during a plant transient or similar event, data from NUREG/CR-5580[1588] were reviewed. This report contained details from 138 incidents of advertent or inadvertent FPS actuation. Only one incident resulted in failure of the electronic ACS. Based upon these data, a failure rate for the ACS of 0.01 was assumed. Although this estimate may be close to the actual failure rate for a scenario like station blackout, it is probably conservative for most other scenarios. (In addition, the harsh environment criterion was considered by NRR in the licensing of new plants and the ABWR design incorporates features to prevent the failure at one station from affecting the rest of the system.)

Scenarios which require operator action outside the control room are included in most PRAs. The quantification of those scenarios usually includes the probability that the operator will fail to properly respond to an equipment malfunction or other problem in a timely manner. The effect of ACS failure on operator actions can be included in these terms by increasing the operator error probabilities used in the existing PRAs by a factor equivalent to the combined probabilities of card-reader failure, key override unavailability, and operator inability to break through doors before initiation of core damage. These data are presented in Table 3.81-1. However, because it is recognized that this table does not include individual sequences which may have a significantly greater chance of impeded operator action, it was decided to perform a parametric study in order

to determine the impact on the probability of core damage of the variation of those estimates. The results of this study are presented in Table 3.81-2 and discussed below. In addition, a review of the interfacing systems LOCA accident scenarios (ISLOCA) for three typical plants (which were investigated in a separate program) indicated that only one of the three plants had a minimum cutset which included an operator action outside of the control room. This action also had an alternate action inside of the control room.

Frequency Estimate

In order to calculate the increase in core-melt frequency, the minimum cut sets from existing PRAs for Oconee 3 and Grand Gulf 1 were assumed to represent the ideal condition of no effect of locked doors on operator recovery for PWRs and BWRs, respectfully. This was a reasonable assumption since the scenario of card-reader failure was probably not considered for these early PRAs and was not discussed in the NSAC reports on these PRAs.

The effect of the card-reader ACS failure was studied[64] parametrically by PNL by calculating the total increase in CDF for a corresponding increase in the probability of any event which models failure of operator action. This probability of operator failure was increased by 0.0001, 0.0005, 0.001, 0.01, and 0.1. This quantity was added to all existing parameters in minimum cutsets which represented failure of necessary operator actions outside of the control room. These actions are included in all minimum cutsets, not only the four listed in Table 3.81-1. The results of this study are presented in Table 3.81-2.

Although the maximum probability calculated in Table 3.81-1 is 1.2×10^{-5}, the range of values for the parametric study started at 10^{-4}. However, 1.2×10^{-5} was believed to be a conservative estimate of the maximum increase in operator failure probability, as the events listed in Table 3.81-1 were chosen on the basis of a high speed of core damage initiation. Events which take longer than several hours to develop core damage will probably be minimally affected by impeded operator access, because the operators will have more time to gain access. Therefore, including these events in the calculation for increase in CDF was conservative.

Consequence Estimate

The increase in public risk was an output of the PRA and was also shown in Table 3.81-2. Corresponding values for total public exposure were calculated based upon the estimated number of operating and future plants (90 PWRs and 44 BWRs) with remaining remaining lives of 28.8 and 27.4 years, respectively. As expected, the increase in both core-melt frequency and public risk was negligible at the expected levels of operator impairment (10^{-4}), but became significant at unrealistic levels of impairment (10^{-1}). These calculations contain the implicit assumption that core damage will occur in no more than one hour for all events.

Cost Estimate

Based on the deliberations of the multi-disciplinary group, the cost to evaluate and make modifications to each plant and its procedures was estimated to be approximately \$1.1M/plant.[626] This cost was based on the following factors:

Table 3.81-1
Estimated Probability of
ACS Failure to Prevent Operator Action

Event[4]	Probability			Product[3]
	ACS Fails[1]	Override Fails[1]	Delay Exceeds Limits[2]	
V	0.01	0.01	0.12	1.2×10^{-5}
S_2D	0.01	0.01	0.08	0.8×10^{-5}
AH	0.01	0.01	0.02	0.2×10^{-5}
TMLB'	0.01	0.01	0.01	0.1×10^{-5}

Notes
1 - Estimated
2 - Calculated, assuming limit of 1 hour for all sequences
3 - Based on assumed independence of ACS failure, override failure, and delay of operator until core damage initiates
4 - Minimum cutset accident sequences from WASH-1400:[16]
V - LPIS check valve/system failure
S_2D - 0.5" to 2.0" LOCA combined with loss of ECCS injection
AH - Medium to large LOCA and failure of ECCS recirculation
TMLB'- TMI sequence

Table 3.81-2
Calculated Increase in
Core-Melt Frequency and Public Exposure

Operator Failure Probability[1]	Core-Melt Frequency ($\times 10^{-5}$/RY)				Public Dose Increase (man-rem)
	PWR	Δ	BWR	Δ	
Base Case	1.408	-	2.475	-	-
0.0001	1.411	0.003	2.482	0.007	5.2×10^{2}
0.0005	1.425	0.017	2.509	0.034	2.6×10^{3}
0.001	1.442	0.034	2.543	0.068	5.2×10^{3}
0.01	1.754	0.35	3.149	0.674	5.2×10^{4}
0.1	4.968	3.6	9.216	6.74	5.2×10^{5}

Note
1 - Increase in probability that operator will fail to perform recovery action within the necessary time due to card-reader ACS failure and locked doors.

(1)	A one-time evaluation of existing plant locked doors and barriers	$ 200,000
(2)	Resolution of adverse safety findings [Cost for maintaining keys for a security force of 24 per plant was estimated to be $21,000/reader.[627] Training for security and operational personnel based on 50 operators and security personnel for 1 day/year/plant, over the lifetime of the plant (28 years) was assumed to be (1/365)(50)(28) ($100,000) = $391,232]	400,000
(3)	Ongoing program to ensure future reduction of safeguards impact on safety ($10,000/year for an average reactor lifetime of 28 years)	280,000
(4)	NRC reviews of plant modifications	200,000
	TOTAL:	$1,080,000

These estimates could be high for a plant that was in substantial compliance with the recommendations in Generic Letter 87-08[1437] and Regulatory Guide 5.65.[1438] However, because the estimated safety benefit for these plants would be a decrease in CDF significantly less than 10^{-5}, these plants would not meet the substantial additional protection criterion of the backfit rule (10 CFR 50.109).

Value/Impact Assessment

The value/impact assessment is presented in Table 3.81-3.

Table 3.81-3
Value/Impact Assessment

Probability Increase	Total Cost ($M)	Risk Reduction (man-rem)	S (man-rem/$M)	Priority Ranking
0.0001	150	5.2×10^2	3.5	DROP/LOW
0.0005	150	2.6×10^3	17	LOW
0.001	150	5.2×10^3	35	LOW/MEDIUM
0.01	150	5.2×10^4	350	MEDIUM/HIGH
0.1	150	5.2×10^5	3500	HIGH

Other Considerations

(1) The most probable effect of locked doors on reactor safety was believed to be represented by an increase in the probability of failure of the operator to leave the control room and perform actions required for recovery of less than 0.0001. This corresponded to a priority rating which was borderline between Drop and Low priority. Even if this estimate was

inaccurate by an order of magnitude, the corresponding priority ranking would be borderline between Low and Medium.

(2) Even with a conservative assumption regarding the impact of failure of the ACS on the probability of preventing operator recovery action, the issue would not satisfy the requirements of the backfit rule (10 CFR 50.109). Specifically, it was stated in SECY-91-270[1439] that, with limited exceptions, a reduction of CDF of at least 10^{-5} was needed to satisfy the substantial additional protection criterion of that rule. However, Table 3.81-2 shows that, with the probability of operator failure due to ACS failure as high as 10^{-2}, the change in core-melt frequency does not reach this value. Further, as shown in Table 3.81-1, the best estimate of the increase in the probability of operator failure is in the range of 10^{-5}.

(3) This evaluation was not intended to address the effect of locked doors on worker safety in an operating plant. A nuclear power plant has many inherently dangerous materials which may present a significant hazard to untrained personnel, but do not significantly affect the ability of the plant to safely shut down in the event of an accident or transient. While it was recognized that these dangers pose legitimate concerns, it is beyond the authority of the NRC to regulate working conditions other than radiological hazards.

(4) The consequence and cost estimates described above were based on a remaining life of 28.8 years and 27.4 years for PWRs and BWRs, respectively, consistent with the original 40-year license period. If it were assumed that 75% of the plants will have their licenses extended for an additional 20 years, the remaining life would be increased by 15 years. This would have very little impact on the value/impact assessment described above.

CONCLUSION

The estimated frequency of card-reader ACS failure and its impact on plant safety indicated that improvements in this area were not a cost-effective way to increase overall plant safety. Furthermore, the multi-disciplinary task group concluded that the locks and barriers associated with these areas could easily be defeated or bypassed in an emergency situation, if necessary, provided there were enough time to take the necessary steps. In addition, implementation of the regulatory guidance associated with rulemaking[1436] resulted in better coordination between plant security and operations personnel. Thus, this issue was given a LOW priority ranking (See Appendix C). Consideration of a 20-year license renewal period did not change the priority of the issue.[1564]

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1436. Federal Register Notice 51 FR 27817, "10 CFR Parts 50 and 73, Miscellaneous Amendments Concerning Physical Protection of Nuclear Power Plants," August 4, 1986.

1437. NRC Letter to All Power Reactor Licensees, "Implementation of 10 CFR 73.55 Miscellaneous Amendments and Search Requirements (Generic Letter 87-08)," May 11,1987.

1438. Regulatory Guide 5.65, "Vital Area Access Controls, Protection of Physical Security Equipment, and Key and Lock Controls," U.S. Nuclear Regulatory Commission, September 1986.

1439. SECY-91-270, "Interim Guidance on Staff Implementation of the Commission's Safety Goal Policy," August 27, 1991.

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1588. NUREG/CR-5580, "Evaluation of Generic Issue 57: Effects of Fire Protection System Actuation on Safety-Related Equipment," (Vol. 1) December 1992, (Vol. 2) December 1992, (Vol. 3) December 1992, (Vol. 4) December 1992, (Vol. 5) December 1992.

ISSUE 87: FAILURE OF HPCI STEAM LINE WITHOUT ISOLATION

DESCRIPTION

Historical Background

The HPCI steam supply line has two containment isolation valves in series: one inside and one outside of the containment. Both are normally open in most plants; however, two plants were found to operate with the HPCI outboard isolation valve normally closed. The HPCI supply valve, located adjacent to the turbine, and the turbine stop valve are normally closed. This issue addressed a postulated break in the HPCI steam supply line and the uncertainty regarding the operability of the HPCI steam supply line isolation valves under those conditions.[824] A similar situation can occur in the RWCU system which has two normally open containment isolation valves that must remain open if the system is to function.[830]

The operation of the valves is tested periodically without steam. Due to flow limitations at the valve manufacturers' facilities, only the opening characteristics are tested under operating conditions. Therefore, the capability of the valves to close when exposed to the forces created by the flow resulting from a break downstream had not been demonstrated. However, there are reasons why the valves may operate under these accident conditions. The containment isolation valves are specified to open or close within 15 to 20 seconds. Calculations performed by Bechtel[826] indicated that the mass flow through the HPCI steam line isolation valves reduces from 1470 lbm/sec. at the time of a break to 328 lbm/sec. after 0.135 seconds and remains constant until the valve closes.

Isolation valves are selected by the A/E for each plant. This results in a diversity of valves and valve types from plant to plant and increases the difficulty of demonstrating valve operating capability. Some plants have "Y-type" globe valves while others have gate valves. One plant using globe valves for HPCI steam supply isolation had the valve inside containment positioned such that the steam flow exerted a force on the valve skirt in the closed position. This force is expected to reduce the closing torque requirement of the valve motor-operator and increase the probability that the valve will close when a large amount of steam is flowing through the valve. Also, some valve experts believe that the force required to open gate valves under pressure is greater than the force required to close the valves under flow.

Safety Significance

In Mark I containments, the HPCI steam line exits the drywell and enters the torus compartment where it typically traverses approximately a 75° arc before exiting to the HPCI pump room. In the four corners of the reactor building along the torus compartment are four triangular-shaped rooms which house the RHR/LPCI system, the RCIC system, and the core spray system. In some reactor buildings, there is a ventilation opening or a door, usually open, between the rooms housing the emergency core cooling pumps and the torus compartment. Given an unisolated break of the HPCI steam supply line in the torus compartment, the environment in the emergency core cooling pump rooms may exceed design limits. This places in jeopardy the other systems required to cool the core.

In Mark II containments, the emergency core cooling components are typically housed in individual rooms which are contained in the large, annular-shaped area about the suppression pool. The HPCI steam supply line exits the containment and is then routed down through two floors to the room containing the HPCI turbine and pump. Again, given an unisolated break of the HPCI steam supply line, other systems which may be required to cool the core may be placed in jeopardy.

Possible Solutions

A proposed solution to the HPCI problem was to require that the outboard HPCI isolation valve be normally closed. However, a small bypass line on those plants not having this feature would be required to prevent thermal shock and water hammer and to provide assurance that leaks in the line would be detected before they become breaks. If the HPCI supply valve was kept normally open -- currently it is kept normally closed -- the probability of not getting steam to the HPCI turbine when needed might not be significantly changed.

Another possible solution that would apply to valves in any system was a demonstration by test or the verification of use in other service applications that certified the operability of the valve under line rupture flow conditions. If the normal HPCI steam flow rate approximates that estimated for a break in the steam line, the valves might be tested by individually closing them when the HPCI turbine is in operation.

PRIORITY DETERMINATION

Frequency Estimate

In the Browns Ferry 1 IREP study,[367] the frequency of intermediate-size steam line breaks (in which size category the HPCI steam supply line is included) is 2×10^{-4}/RY. It was also assumed that a break is equally probable at any point in the steam lines of this size and category. The HPCI steam supply lines were estimated to constitute 23% of the steam lines in the intermediate-size category. Hence, the frequency of a HPCI steam supply line break was assumed to be 5×10^{-5}/RY.

The probability that both steam supply line isolation valves will fail to close was difficult to determine on a probabilistic basis because of the lack of engineering data. If one valve fails to perform its intended function because of conditions which exceed its design capability, it would be most probable that the second valve would also fail to function. As an upper bound calculation, it was assumed that the valve failure rate will be unity, given a line break, and that the dependency between valves was also unity. The lower bound was calculated by assuming that the valve design was adequate and that there were no failure dependencies between the valves. Thus, the frequency of both valves failing was obtained by taking the product of the independent failure frequency of both valves.

The major contribution to the accident scenario considered was the dependency between the unisolated steam line breaks and the low-pressure injection systems. For both the upper and lower bound calculations, it was assumed that the dependence is unity, i.e., that the low-pressure injection systems will fail, given an unisolated line break.

If, during the accident condition described, the core is maintained covered by the feedwater system, the steam mass flow generated by decay heat should lower to a point that would permit the closing of an isolation valve. One means available would be electrically closing the isolation valve inside the containment; the other means available would be manually closing one of the isolation valves. If the steam flow forces prevent the initial closure of the isolation valve, the motor control breakers will likely trip from the overcurrent condition before motor damage can occur. Furthermore, the isolation valve inside containment will not have been exposed to the steam environment from the broken line. Resetting the motor control breaker would then permit energizing the valve motor and closing the isolation valve from the control room.

The second method available was to close one of the isolation valves by manual actuation of the hand crank. This would require suiting the operator in special garments and possibly using an airpack. Due to the expected high temperature in the torus compartment, the isolation valve inside the containment would be the valve most likely closed.

NEDO-24708A[827] analyzed an unisolatable 0.5 square-foot steam line break inside containment, which approximated a break of the 10 in.(0.55 ft^2) HPCI steam line from the time of the break up to the time that the low pressure systems would begin injection (225 seconds). The analysis also included the water injected by the RCIC, but this should be minimal. The 0.5 square-foot line break model predicted that the system pressure will fall below 300 psia at approximately 210 seconds after the break occurs. The water level will still be above the core and the condensate and the condensate booster pumps can be used (for those systems having a turbine-driven feed pump) to supply feedwater to the reactor. For those feedwater systems having motor-driven feed pumps, the feedwater system can supply feedwater continuously following the reactor trip. With the feedwater system providing cooling water, the fuel will remain covered until a HPCI isolation valve is closed and the RHR system is restored to operation.

It was calculated that 12,500 gallons/hour of water at 94°F will be converted to steam at 212°F in absorbing the decay heat from the fuel. At this rate of consumption, a 500,000 gallon condensate tank could be emptied in 40 hours. In order to maintain adequate coolant for the extended time period, the vacuum must be restored in the condenser and the decay heat dissipated using the condenser. This will also necessitate using the auxiliary boiler to provide steam for the gland seals. Having the condensers available will reduce the steam pressure in the reactor, thus reducing the amount of steam that will be discharged through the broken HPCI steam supply line and decreasing the consumption of water from the condensate storage tank. This action will also lower the amount of heat and humidity being dumped into the torus compartment.

The probability of the loss of the feedwater during a 168-hour interval, the time assumed necessary to restore the RHR system following a HPCI steam supply line break, was calculated to be 0.03. This was based on the Browns Ferry IREP[367] frequency of transients that result in loss of feedwater (~1.4/RY). This equated to a mean time between failure of 5,570 hours. Assuming an exponential distribution, a failure rate of 1.8×10^{-4}/hour results.

Of concern were the operator actions needed to maintain the operation of the main feedwater system. Although this is an activity with which the operator should be very familiar, detecting that the HPCI is not providing make-up inventory may not

be immediate. Further, the inventory in the hotwell must be maintained by flow from the condensate storage tank. To obtain an adequate flow, it may be necessary to re-establish the vacuum in the condensers. As reported in NUREG/CR-3933,[828] PRAs assign a probability of 0.1 for failure to recover the power conversion system in a short interval. In this accident, the time needed to make the necessary operating adjustments will not be as short as required for transients or small breaks in liquid coolant lines. In addition, approximately ¼ or ½ of the make-up water requirements will be provided by one- or two-pump operation of the CRD hydraulic system. Thus, a human error probability of 0.05 was assigned. The total probability of failing to maintain coolant inventory with the feedwater systems for 168 hours was estimated to be (0.05 + 0.03) = 0.08. Thus, the frequency estimates were:

Upper Bound: $(5 \times 10^{-5})(1)(1)(0.08) = 4 \times 10^{-6}$ core-melt/RY
Lower Bound: $(5 \times 10^{-5})(10^{-3})(10^{-3})(1)(0.8) = 4 \times 10^{-12}$ core-melt/RY

Closing the outboard isolation valve and opening the supply valve was assumed to result in no net change in the unavailability of the HPCI and, therefore, the frequency of other accident sequences was unchanged. Closing the outboard isolation valve until the HPCI is commanded does not reduce the accident rate from breaks that occur when the HPCI is energized or go undetected prior to the HPCI being energized. With the inclusion of a bypass line to prevent thermal shock, this contribution was believed to be much smaller than the long-term exposure with the line pressurized. Hence, the remaining contribution was not considered to be significant.

The BNL estimate[829] of the frequency of a core-melt accident due to an unisolated break outside the containment in a six-inch RWCU line was 1.4×10^{-5}/RY. The study also conservatively assumed that the conditional probability for the isolation valves failing to close, given a line break, was 1.

Consequence Estimate

A break in the HPCI steam supply line would be a LOCA outside containment. This would be closely equivalent to the PWR Event V sequence identified in WASH-1400.[16]

The consequences were obtained using the CRAC Code.[64] An average population of 340 persons per square mile (which is the average for U.S. domestic sites) was assumed from an exclusion area ½ mile about the reactor to a 50-mile radius about the reactor. Typical midwest site meteorology was assumed. Based on these assumptions, a release produces an exposure of 5×10^{6} man-rem. With upper and lower bound frequencies of 4×10^{-6} and 4×10^{-12} core-melt/RY, the upper and lower values of risk exposure were 20 man-rem/RY and 2×10^{-5} man-rem/RY, respectively. Based upon an average remaining life of 24 years for 24 BWRs having a HPCI system with open isolation valves, the risk posed by this issue has an upper bound of 11,500 man-rem and a lower bound of 1.1×10^{-2} man-rem. The consequences of the RWCU line break sequence would be 70 man-rem/RY and 40,000 man-rem total. Thus, the maximum risk reduction associated with this issue was estimated to be 51,500 man-rem.

Cost Estimate

Industry Cost: Implementation of the proposed change to leave the outboard isolation valve closed was estimated to be 2.5 man-years. This included: (1) an engineering review of the logic for HPCI initiation to assure that the valve will be commanded open and will properly isolate if required; (2) preparation of changes to procedures (normal and emergency); (3) revision to operator training covering the change; (4) revision to the FSAR; (5) license amendments; and (6) hardware changes. No added maintenance costs were anticipated. No hardware costs were included for the addition of a bypass line because it was believed that most reactors already had this feature. At an average cost of $100,000/man-year, the total industry cost was estimated to be $6.75M.

NRC Cost: It was estimated that 1 man-month/reactor would be required for a total cost of $210,000 for all reactors. However, there was at least one reported instance in which the isolation valve could not be opened under pressure; this occurrence was reported in AEOD/T420.[825] If these valves would have to be modified to open under pressure, the costs would be much greater.

Performing qualification tests on a selected sample of RWCU isolation valves and actuators, and demonstrating, by analyses, that the other valves and actuator combinations will perform satisfactorily were estimated to cost $1M. If actuators have to be replaced, this would add to the costs.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $7.96M.

Value/Impact Assessment

Based on a potential risk reduction of 51,500 man-rem and a cost of $7.96M, the value/impact score was given by:

$$S = \frac{51{,}500 \text{ man-rem}}{\$7.96M}$$

$$= 6{,}500 \text{ man-rem/\$M}$$

Other Considerations

(1) The occurrence of the analyzed event would result in the loss of one defense layer (containment). Other considerations, which in individual cases may reduce the risk associated with this issue, include the absence of ventilation openings or open doors between the torus compartment and the pump rooms. The absence of these openings reduces the common cause failure potential of the RHR/LPCI, RCIC, and core spray systems with the HPCI steam supply line break. Consideration should be given to reducing the risk if the isolation valves were selected based on the requirement to close under line break/steam mass flow conditions. This concern could be eliminated if it could be shown by test or from actual application that valve operation was verified under loads equivalent to line break conditions.

(2) A similar situation exists for the RCIC system. Since the RCIC steam line is smaller than the HPCI line, the risk may not be as great but would still add substantially to the values estimated previously.

CONCLUSION

Based on both the RWCU and HPCI event sequences and the Event V consequences, this issue was given a high priority ranking (See Appendix C). In resolving the issue, a study[1590] was made of valve assemblies in high energy BWR systems outside containment and the staff conducted a two-phase valve test program: Phase 1 was reported in NUREG/CR-5406[1403] and Phase 2 was reported in NUREG/CR-5558.[1404] In addition, laboratory tests of DC-powered MOVs were conducted and reported in NUREG/CR-5720.[1589]

In general, it was found that many of the valves of concern in the issue did not have sufficient margin to close under the blowdown loads that would be encountered under the design basis conditions caused by a pipe break. The primary reasons for this were: (1) at the time the valves and operators were sized, the internal mechanisms and load paths of the MOVs were not well understood; and (2) the standard equation used by the industry to predict MOV stem loads did not adequately account for all of the force components resulting from the interaction of the blowdown flows on the valve internal parts.

The results of the Phase 1 test program were factored into the development of Generic Letter No. 89-10[1217] thus providing licensees with the best guidance available at that time regarding how they should assure that their MOVs would perform their design basis function. The results of the Phase 2 test program were used in the development of Supplement 3 to Generic Letter No. 89-10[1217] which provided licensees with further guidance. The staff also conducted training for inspectors and provided computer software to aid in identifying these problems on site. Thus, this issue was RESOLVED[1406] and requirements were issued to licensees in Generic Letter No. 89-10.[1217] The related ACRS concern for the design basis for valves that might be subjected to significant blowdown loads was addressed in Issue 152. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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ISSUE 89: STIFF PIPE CLAMPS

DESCRIPTION

Historical Background

This issue was identified[1447] following a staff evaluation of allegations that improper consideration of "stiff" pipe clamps in Class 1 piping systems could result in unsafe plant operation. IE Information Notice No. 83-80[1448] was issued to alert OLs and CPs of this concern. In the staff's evaluation, it was found that piping designers often assumed that the clamp effects on piping systems were negligible and did not warrant any explicit consideration. This assumption was acceptable for most clamp applications. However, for some applications, certain piping system conditions coupled with specific stiff pipe clamp design requirements could result in interaction effects that should be evaluated in order to determine the significance of pipe stresses induced.

Safety Significance

Stiff pipe clamps were installed because of requirements for piping systems to withstand dynamic loads such as SRV discharges to suppression pools, LOCA-induced loads, and seismic loadings. A preloading of pipe clamp U-bolts or straps (which imposes a constant compressive load on the piping) is necessary to prevent stiff pipe clamps from lifting off piping under dynamic loading conditions. Since clamp-induced stresses are generally not significant with conventional pipe clamps, the pipe stresses induced by stiff pipe clamps generally were also not considered. Therefore, it was believed that further analyses of these stresses on piping systems were necessary before determining whether the stresses were significant.[1447]

In addition to the large preloading of the clamps, four other new design features were identified by the staff as requiring additional analyses because of their difference from conventional pipe clamps. These were: (1) use of high-strength or non-ASME approved materials; (2) local surface contact on the pipe; (3) uncommonly thick and/or wide design of clamp; and (4) clamp applications to piping components other than straight pipe, such as pipe elbows.

If neglect of the additional stress from stiff pipe clamps results in overestimating the pressure-retaining capabilities of piping systems, the probability of pipe breaks caused by dynamic loads may be higher than previously estimated. This increased probability could potentially result in an increased CDF that could lead to PRAs understating the public risk. This issue affected those operating and future plants that installed stiff pipe clamps.

Possible Solution

A possible solution could have the following elements:

(1) Evaluation of the local pipe stresses induced by stiff pipe clamps under all loading conditions;

(2) If the evaluation in (1) above indicated that clamp-induced pipe stresses were unacceptable, hardware modifications should be considered;

(3) As recommended[1447] by the staff, NRC could submit a request to ASME to revise Section III of the Code to include procedures for: (1) categorizing pipe stresses resulting from clamp-induced loads; and (2) evaluating those clamp applications where the ASME Code stress indices and flexibility factors do not apply;

(4) As recommended[1447] by the staff, a technical assistance program could be initiated to experimentally and analytically evaluate the interactions between piping and pipe clamps. The goal of this program would be to develop a simplified method to facilitate staff evaluations of clamp-induced pipe stresses.

PRIORITY DETERMINATION

Assumptions

It was assumed[1447] that the issue affected La Salle 1 and 2, Quad Cities 1 and 2, Dresden 2 and 3, and all plants whose operation or construction began in September 1983 or later. Thus, there were 44 operating plants affected by this issue: 27 PWRs and 17 BWRs, with average remaining lives of 33.4 and 28.9 years, respectively. These 44 plants included a few that were under construction at the time of the staff's evaluation.[1447] It was also assumed[64] that none of the 44 plants had upgraded their stiff pipe clamps as a result of IE Information Notice No. 83-80[1448] and all 44 plants had stiff pipe clamps that required some degree of hardware modification.

It was assumed that 20 future plants (10 PWRs and 10 BWRs) would be affected by this issue. The Oconee 3 and Grand Gulf 1 PRAs were used as the representative PWR and BWR, respectively.

Frequency Estimate

The risk associated with pipe breaks resulting from the use of stiff pipe clamps can be divided into the following two types: Type 1 seismic-induced pipe breaks, resulting in LOCA and/or reactor transients; and Type 2 pipe breaks in Class 1 piping, resulting from dynamic loads following LOCAs and transients.

Type 1 Pipe Break: The source of quantitative risk information was a study[1065] performed to identify risk-sensitive components in nuclear power plants during and after a seismic event. This study used PRA methodology to expand risk-sensitivity analyses by accounting for seismicity and component fragility data taken from existing nuclear power plant PRAs. To estimate the risk reduction achievable, the adjusted case assumed upgrades to various piping systems such that there would be an increase by a factor of 5 in the median peak ground acceleration (the level of peak ground acceleration at which a component has a 50% probability of failure) for these piping systems. The reduction in CDF due to this piping upgrade was 8% (0.08) for PWRs and 6% (0.06) for BWRs.

It was estimated that, for the base case, the affected annual CDF from seismic events was approximately 5.2×10^{-6}/RY for PWRs and 9.1×10^{-5}/RY for BWRs. The

change in piping system reliability that could result from the possible solution would be less than the factor of 5 that was used in NUREG/CR-3357[1065] since pipe clamps are only one of the piping system components whose failure contribute to piping system failure probability; others are components such as welds, elbows, branch connections, and snubbers. Therefore, a factor needed to be developed to model the portion of the piping system reliability improvement that would result from improvements to pipe clamps. This factor was assumed to be the fractional difference between the upper and median bending moment capacity of a reference pipe segment. Using the results from NUREG/CR-2405,[1449] this factor was estimated[64] to be 0.145.

For operating plants, to calculate the reduction in CDF that could result from implementation of the possible solution, the product of the following three factors was calculated: piping component contribution; base case; and effects of pipe clamp improvement.

PWRs: CDF Reduction = $(0.08)(5.2 \times 10^{-6}/RY)(0.145) = 6.0 \times 10^{-8}/RY$

BWRs: CDF Reduction = $(0.06)(9.1 \times 10^{-5}/RY)(0.145) = 7.9 \times 10^{-7}/RY$

For future plants, the CDF reduction was assumed to be the same as that for operating plants.

Type 2 Pipe Break: The Oconee 3 and Grand Gulf 1 PRAs were reviewed[64] to identify those cut sets containing a hardware failure in an ECCS. For each element so identified, the largest hardware failure probability (typically associated with a valve or pump) was identified and its percentage contribution to the element's total failure probability was calculated. These percentage contributions were calculated for all the identified elements at Grand Gulf 1 and Oconee 3. These were averaged to yield values of 6.1% for Grand Gulf 1 and 6% for Oconee 3. These values were assumed to represent the failure contribution to the CDF resulting from Class 1 pipe breaks arising from dynamic loads induced following LOCAs and transients, and were used as a surrogate measure in estimating the risk contribution from Type 2 pipe breaks.

The same factor of 0.145 used above for a Type 1 pipe break was used to represent the portion of piping system reliability improvement that could result from improvements to pipe clamps. Based on the non-seismic total CDF reported in NUREG/CR-3357[1065] ($6 \times 10^{-5}/RY$ for PWRs and $2.9 \times 10^{-5}/RY$ for BWRs), the changes in CDF resulting from implementation of the possible solution were:

PWRs: Reduction in CDF = $(0.060)(6.0 \times 10^{-5}/RY)(0.145) = 5.2 \times 10^{-7}/RY$

BWRs: Reduction in CDF = $(0.061)(2.9 \times 10^{-5}/RY)(0.145) = 2.6 \times 10^{-7}/RY$

Therefore, for operating plants, the total possible reduction in CDF, considering both Type 1 and Type 2 pipe breaks, was $5.8 \times 10^{-7}/RY$ and $1.1 \times 10^{-6}/RY$ for PWRs and BWRs, respectively. This reduction in CDF will be realized only if hardware modifications are made to the stiff pipe clamps.

For future plants, the CDF reduction was assumed to be the same as that for operating plants.

Consequence Estimate

Type 1 Pipe Break: The reduction in CDF, combined with the offsite consequences of the appropriate release categories[64] resulted in a potential public risk reduction of 0.3 man-rem/RY for PWRs and 2.1 man-rem/RY for BWRs. These values were used for all affected operating and future plants.

Type 2 Pipe Break: The reduction in CDF, combined with the offsite consequences of the appropriate release categories,[64] resulted in a potential public risk reduction of 0.6 man-rem/RY for PWRs and 1.4 man-rem/RY for BWRs. These values were used for all affected operating and future plants.

Assuming the 44 operating plants (27 PWRs and 17 BWRs) will need some degree of hardware improvements, the potential public risk reduction over their remaining lives was estimated to be:

$$[(0.3 + 0.6)(27)(33.4) + (2.1 + 1.4)(17)(28.9)] \text{ man-rem} = 2{,}500 \text{ man-rem}.$$

Assuming that there will be 20 future plants (10 PWRs and 10 BWRs) affected by this issue, the potential public risk reduction over their 40-year life would be:

$$[(0.3 + 0.6)(10)(40) + (2.1 + 1.4)(10)(40)] \text{ man-rem} = 1{,}760 \text{ man-rem}.$$

Cost Estimate

Industry Cost: Implementing the possible solution at each of the 44 operating plants would be done in two parts: (1) perform a piping analysis to assess the effects of pipe clamp to piping interaction; and (2) modify the stiff pipe clamps that produce significant pipe clamp to piping interaction.

A total of 28 man-weeks were assumed for the pipe clamp and piping analyses. At a cost of $2,270/man-week, this resulted in a cost of $63,560/plant and a total of $2.8M for all 44 affected plants.

For the 44 plants that require some degree of hardware modifications, the cost per plant was based on the estimate[961] of the cost of hangers for 1000 feet of 8-inch pipe; at $21/foot, this cost was $21,000/plant. Installation labor costs were estimated[64] based on $44/man-hour burdened labor rates. Based on an estimate[961] of 4.6 man-hours per linear foot, a total of 4600 man-hours/plant would be required. Applying a 10.08 adjustment factor for labor productivity effects for work in radiation zones and congested areas, manageability, and access/handling difficulties, labor costs were estimated to be $2.04M/plant. Summing over all plants yielded $0.92M for hardware and $89.8M for labor, for a total of $90.72M for 44 plants.

A total of 8 man-hours/RY were estimated for the inspection of the replacement pipe clamps at those plants requiring hardware madifications. For the 27 PWRs and 17 BWRs with average remaining lives of 33.4 and 28.9 years, respectively, and at a cost of $2,270/man-week, the total cost was $0.63M. Thus, the total industry backfit cost was $(2.8 + 90.72 + 0.63)M or $94.15M.

For the 20 future plants, the effect of stiff pipe clamps on piping can be evaluated and taken care of in the design and analysis stage, if required, and no backfit hardware modification will be necessary. Assuming that the cost/plant

is also $63,560 to perform a piping analysis during the design and analysis stage to assess the effects of pipe clamp to piping interaction, the total cost for these plants will be $1.3M. Assuming a total of 8 man-hours/RY would also be required for inspection of stiff pipe clamps, the total industry operating and maintenance cost was estimated to be $[(20)(40)(8)(2270)/40]M or $0.4M. Therefore, the total industry cost for implementing the possible solution was $(1.3 + 0.4)M or $1.7M.

NRC Cost: NRC implementation of the possible solution at the 44 operating plants could be quite extensive. NRC would develop proposed procedures categorizing pipe stresses resulting from clamp-induced loads and procedures for evaluating those clamp applications where the ASME Code stress indices and flexibility factors are not applicable. Developing these procedures, a complicated problem, was estimated to require approximately 2 man-years of labor to develop, review, and approve. At $100,000/man-year, this cost would be $0.2M.

Implementation of the possible solution also included establishing a program to acquire experimental data to verify analytical techniques and results. The test equipment was estimated at $250,000 and preparation of test procedures, QA activities, and analysis of test results were estimated to require 1 man-year of labor at a cost of $100,000/year. Thus, the total cost of the program was $0.35M.

A generic letter directed to potentially affected plants would be required and this was estimated[961] to take 6 man-weeks. At a cost of $2,270/man-week, this cost was $0.01M. Review of licensee submittals in response to the generic letter was assumed to require 5 man-weeks/plant. At $2,270/man-week, the total cost for 44 plants was $0.5M.

The cost for reviewing operations and maintenance of the possible solution was estimated to be 0.5 man-day/RY. At $2,270/man-week, this cost will be $227/RY. Multiplying $227/RY by 44 plants over their average remaining lives resulted in a total operations and maintenance cost of $0.32M. Thus, the total NRC backfit cost was $(0.2 + 0.35 + 0.01 + 0.5 + 0.32)M or $1.38M.

Assuming the cost to develop procedures categorizing pipe stresses resulting from clamp-induced loads and procedures for evaluating those clamp applications was $0.2M, the cost for a program to acquire experimental data was $0.35M. Assuming also that the cost to update relevant Regulatory Guides and SRP[11] Sections was $0.5M and the cost to review operations and maintenance was $227/RY, for 20 plants with a 40-year plant life, the total cost was $0.2M. Therefore, the total NRC front-fit cost was $(0.2 + 0.35 + 0.5 + 0.2)M or $1.25M.

Total Cost: For the 44 operating plants, the total industry and NRC cost associated with the possible solution was $(94.15 + 1.38)M or $95.53M. For the 20 future plants, the total industry and NRC cost associated with the possible solution was $(1.7 + 1.25)M or $2.95M.

Value/Impact Assessment

Using the above estimates of total public risk reduction and implementation costs, separate value/impact scores were developed for the 44 operating plants and the 20 future plants.

(1) Operating Plants: Based on a risk reduction of 2,500 man-rem and a cost of $95.53M for 44 plants, the value/impact score was given by:

$$S = \frac{2{,}500 \text{ man-rem}}{\$95.53M}$$

$$= 26 \text{ man-rem/\$M}$$

(2) Future Plants: Based on a public risk reduction of 1,760 man-rem and a cost of $2.95M for 20 plants, the value/impact score was given by:

$$S = \frac{1{,}760 \text{ man-rem}}{\$2.95M}$$

$$= 597 \text{ man-rem/\$M}$$

Other Considerations

(1) Extensive work in radiation zones will be required at the 44 operating plants that need pipe clamp replacements and hardware changes. Using data from NUREG/CR-4627,[961] it was estimated that 46,000 man-hours/plant would be required. This work is in containment with an assumed radiation dose rate of 0.025 rem/hr.[64] The total occupational dose is (44 plants)(0.025 rem/hr)(4.6×10^4 man-hours/plant) or 51,000 man-rem.

(2) The occupational dose reduction due to accident avoidance was calculated from the reduction in CDF multiplied by the assumed accident dose of 19,860 man-rem.[64] The possible solution reduces the CDF in 44 plants which have an occupational dose rate reduction of 1.6×10^{-2} man-rem/RY: (19,860 man-rem x 5.8×10^{-7}/RY) for PWRs and (19,860 man-rem x 1.1×10^{-6}/RY) for BWRs. With the 27 PWRs having an average remaining life of 33.4 years and 17 BWRs having an average remaining life of 28.9 years, this resulted in a best estimate total occupational dose reduction due to accident avoidance of 22 man-rem.

(3) The accident avoidance cost savings for PWRs were estimated to be the CDF (5.8×10^{-7}/RY) multiplied by the estimated cost of a core-melt accident ($1,650M) multiplied by the estimated remaining life of 33.4 years. The accident avoidance cost savings for BWRs were estimated to be the CDF (1.1×10^{-6}/RY) multiplied by the estimated cost of a core-melt accident ($1,650M) multiplied by the estimated remaining life of 28.9 years. This resulted in a total cost of $1.75M.

CONCLUSION

Based on the value/impact assessment and total reduction in public risk, the backfit actions described above were not justified for the 44 operating plants considered. In addition, the accident avoidance cost savings and occupational dose reduction due to accident avoidance were not significant when compared to the cost and doses used in the value/impact score. However, the occupational dose increase is higher (51,000 man-rem) than the best estimate public risk reduction (2,500 man-rem). This occupational dose increase supported a LOW priority ranking (See Appendix C) for this group of plants, because the high occupational dose increase indicated that more dose would be taken modifying the stiff pipe clamps

than the total estimated benefit realized from the solution. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

For future plants, the value/impact consideration was more favorable since the effect of stiff pipe clamps on piping could be evaluated in the design and analysis stage. Furthermore, the occupational dosage for front-fitting future plants would be limited to operation and maintenance and should be minimal. Thus, this issue had a medium priority ranking (See Appendix C) for future plants only. RES recommended that a possible update of relevant Regulatory Guides and SRP[11] Sections be contemplated to ensure that interface design procedures are used by CPs to control the flow of design information from the support design group (which has the responsibility for the design of stiff clamps) to the pipe stress analysis group.[1476] Items 3 and 4 delineated in the Possible Solution should also be considered for future plants.

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ISSUE 90: TECHNICAL SPECIFICATIONS FOR ANTICIPATORY TRIPS

DESCRIPTION

Historical Background

Reactor protection systems (RPS) or "scram" systems are tripped by many diverse signals. The purposes of these various signals can be broadly divided into three classes: protection of the reactor core (e.g., overpower signals); protection of major components (e.g., vessel overpressurization signals); and anticipatory trips. The purpose of an anticipatory trip signal is to scram the reactor at the very beginning of a transient and thus minimize the degree of upset of the plant and avoid actuation of engineered safety features.

By definition, credit is not taken for an anticipatory trip in a plant's safety analyses, even to satisfy a single failure criterion. (Conversely, if a transient analysis calculation upon which TS are based takes credit for early reactor scram due to an "anticipatory" trip, the trip can no longer be considered "anticipatory.") Originally, it was AEC (and then NRC) regulatory policy to consider such trips to be installed for the licensees' convenience rather than for licensing purposes.[630] Thus, no TS requirements were placed on these trips. At the time the STS was introduced, this policy was changed and all trips in the RPS were included in the STS. However, plants licensed prior to the advent of STS were not backfitted with TS on anticipatory trips. In addition, post-STS reviews of custom TS done after the STS were introduced did not require the inclusion of specifications on anticipatory trips.

This issue originated when Region II noted the anomaly and found that licensees were often performing little or no maintenance on these trips in the absence of TS requirements.[630] With no mention of these trips in the TS, Region II could take little action even in cases where inspectors had reason to doubt the operability of these trips. DSI/NRR recommended that the issue be included in the broader study involving the overall adequacy of the TS. However, at the time this issue was evaluated, RSB/DSI had not defined a scope or schedule for a systematic study of all TS.

Safety Significance

The safety significance identified[630] was that, "because anticipatory trips are a part of the protection system, a failure or maintenance action in the anticipatory trip could cause other trips relied on in the accident analysis to be degraded below an acceptable level." The design of the RPS, however, leans strongly towards a fail-safe direction, i.e., failure of any channel may cause an inadvertent reactor scram, but should never prevent a trip of another channel from scramming the reactor. Questions of this nature are valid (e.g., can the W scram-on-turbine-trip interact with other channels via the P-7 interlock?), but the DL/NRR memorandum[630] did not provide any specific concerns. Moreover, ICSB/DSI mentioned none in its examination of this issue,[631] and the fault tree analysis of WASH-1400[16] (Appendix II, §5.2) found no such interaction. In the absence of specific concerns, it was concluded that this part of the issue was better

treated under the auspices of the ATWS program and was not taken into consideration in this evaluation.

The second area of potential safety significance was a plant's response to a transient. Since anticipatory trips reduce the degree of plant upset, they also (in principle) reduce the frequency of challenges to engineered safety features, and thus (again, in principle) reduce the frequency of transient-initiated accidents.

Possible Solution

The proposed solution was implicit in the definition of the issue: impose TS requirements on anticipatory trips. Such specifications would include: (1) limiting safety system settings (LSSS), which provide setpoints; (2) limiting conditions for operation (LCO), which require equipment to be operable during appropriate operational modes; and (3) surveillance requirements (SR).

PRIORITY DETERMINATION

Assumptions

A search through some older TS uncovered the following anticipatory trips:

(1) PWR - High neutron flux, source range
PWR - High neutron flux, intermediate range
(2) PWR - Turbine trip
(3) PWR - Low steam generator level coincident with steam-feed mismatch
(4) BWR - High neutron flux, source range

Because these trips are notable via their absence in the TS, there is no guarantee that this list is complete. Nevertheless, these anticipatory trips should be representative. There are other trips (e.g., PWR RCP breaker open) which have LCOs and SRs, but do not appear in the LSSS. Historically, this is because it is difficult to define "setpoints" for such trips. This is not a safety but a licensing improvement (enforceability) aspect and will not be considered here.

Normally, calculations of scram failure probabilities are done for each channel of the RPS, explicitly accounting for the various 1/2, 2/3, and 2/4 logic matrices with estimates of common mode failure rates included. Using this data, the following simplified assumptions were made.

First, imposing TS on anticipatory trips does not affect the common mode failure rate of the RPS. Thus, when the changes in failure probabilities are calculated, the common mode failures are subtracted out. Second, lack of maintenance of an anticipatory trip is a common mode of both trip channels associated with the anticipatory trip parameter, i.e., if one channel fails, the other is also quite likely to fail. In the calculations, it was assumed that the probability that a trip signal will fail to cause a scram (i.e., both channels failing) is 0.01/demand on an anticipatory trip which is not in the TS. This assumption was based on judgment augmented by conversations with the senior inspector who originated the issue. All other trip parameters were assumed to have failure rates of 10^{-4}/demand, based on Appendix II, §5.2 of WASH-1400.[16]

Frequency/Consequence Estimate

(1) PWR - High Neutron Flux, Source and Intermediate Range

These trips are functional only during reactor startup. They are backed up by the low setpoint of the power range neutron flux channels. Usually, the source range monitor setpoint is set at 10^5 counts/second (which is equivalent to roughly 0.01% of rated reactor power) and the intermediate range setpoint and power range low setpoint are both set at 25% of rated power. Thus, the source range is truly anticipatory in the sense of attempting to stop a transient early while the intermediate range backs up, but does not anticipate, the low power setpoint of the power range channels.

Rod Ejection: The first "transient" of interest is not an anticipated operational occurrence, but is considered an accident. A rod ejection is a reactivity excursion which is, if significant at all, too rapid for the anticipatory nature of the source range trip to make much difference. Thus, the safety contribution comes from increased scram reliability, not early scram. The following assumptions were made: 10 reactor startups/RY[178]; two days of vulnerability/startup (based on judgment); and 10^{-5} rod ejections/RY (based on WASH-1400,[16] Appendix I, §4.3). This translates to 5.5×10^{-7} rod ejections/RY at low power. The change in scram failure rate is $(10^{-2} - 10^{-4})$ for the source and intermediate range trips multiplied by 10^{-4} for the low setpoint power range trip. Thus, the change in core-melt frequency was given by:

$$\Delta F = (5.5 \times 10^{-7}/RY)[(10^{-2})^2 - (10^{-4})^2](10^{-4})$$
$$= 5.5 \times 10^{-15}/RY$$

The consequences are those of a partial core-melt (if all these trips fail) which was bounded by a PWR-5 release (core-melt with the containment not isolated). Using the assumption of a uniform population density of 340 persons/square-mile, a 50-mile radius, a central midwest plain meteorology, and no ingestion pathways, a PWR-5 release results in 10^6 man-rem. Thus, the estimated risk reduction was given by:

$$\Delta FR \leq (5.5 \times 10^{-15}/RY)(10^6 \text{ man-rem})$$
$$\leq 5.5 \times 10^{-9} \text{ man-rem/RY}.$$

Short Periods: Under certain conditions of core burnup and high xenon inventory, differential rod worth tends to concentrate in a relatively narrow vertical range in the core during startup. This effect is much more pronounced in a BWR core (see Issue 6), but can also occur in PWRs. Should this occur, the reactor core will go suddenly from subcritical to supercritical with a rapid positive period (on the order of 10 seconds). Older plants do not have flux rate trips.

If the SRM trip fails and the operator does not terminate the transient manually (assume 10% chance), the reactor core will not be shut down until power reaches the 25% intermediate and power range setpoints. Fuel failure could also occur due to pellet/cladding interaction (PCI) during the rapid power ascension, or due to DNB because of the highly axially peaked power

shape. At the time this issue was first evaluated in August 1984, no such events had occurred at a PWR. IE Bulletin No. 79-12[6] and IE Circular No. 77-07[5] listed 5 such events in BWRs as of May 31, 1979. This corresponded to about 155 BWR-years of experience.

It was assumed that the PWR frequency was at most one-tenth of the BWR frequency, or 3×10^{-3} event/PWR-year. The consequences were also bounded by those of PWR-8 and PWR-9 releases which corresponded to mitigated large break LOCAs without and with containment isolation (i.e., widespread cladding failure but no fuel melting). The WASH-1400[16] assumption of containment isolation failure probability is 0.1. The risk associated with the short period scenario was given by:

$$\begin{aligned}\Delta FR \leq\ & (3 \times 10^{-3}\ \text{event/RY})[(10^{-2} - 10^{-4})\ \text{SRM trip failure/event}] \\ & \times (0.1\ \text{operator failure/event}) \\ & \times [(120\ \text{man-rem/accident, containment isolated}) \\ & \quad + (0.1\ \text{isolation failure/accident})(7.5 \times 10^{4}\ \text{man-rem/accident, containment not isolated})] \\ \leq\ & 2.3 \times 10^{-2}\ \text{man-rem/RY}.\end{aligned}$$

Rod Bank Withdrawal Error: This transient is characterized by a slower reactivity insertion rate than those of the transients discussed above. Thus, fuel failure is not likely to occur because of a high rate of power ascension at the beginning of the transient, but instead may occur due to DNB as the core comes into the power range, possibly with an adverse power distribution due to some rod banks remaining in the core.

For this to happen, the source, intermediate, and power range trips must fail. In addition, the rod stop must fail. A failure rate of 0.1 (rather than 0.01) for the rod stop was assumed since it was associated with the intermediate range detectors. No credit was taken for operator action since the cause of the event was probably operator error. Again, as discussed in the short-period transient, the consequences were bounded by those of PWR-8 and PWR-9 releases, assuming a containment isolation failure probability of 0.1.

In WASH-1400,[16] the frequency of PWR uncontrolled rod withdrawal transients was estimated to be 0.01/RY. It was assumed that half of these occur during startup maneuvers. The risk estimate was given by:

$$\begin{aligned}\Delta FR \leq\ & (0.01\ \text{rod withdrawal events/RY}) \\ & \times (0.5\ \text{percentage in startup}) \\ & \times (10^{-2} - 10^{-4}\ \text{source range failure rate change}) \\ & \times (0.1\ \text{rod stop failure rate}) \\ & \times (10^{-2} - 10^{-4}\ \text{intermediate range failure rate change}) \\ & \times (10^{-4}\ \text{low setpoint power range failure rate}) \\ & \times [(120\ \text{man-rem/PWR-9 release}) + (0.1\ \text{containment failure rate}) \times (7.5 \times 10^{4}\ \text{man-rem/PWR-8 release})] \\ \leq\ & 4 \times 10^{-8}\ \text{man-rem/RY}.\end{aligned}$$

For this transient to progress to core-melt, the high pressurizer pressure, high pressurizer water level, overtemperature and overpower ΔT, and several other trips must fail. However, the DNB event frequency above is already down to about 5×10^{-12}. Thus, even if no credit was taken for

these additional trips and the core-melt resulted in the worst case consequences (5.4×10^{6} man-rem from a PWR-1 release, where the core-melt causes a steam explosion which ruptures both the reactor vessel and the containment), the resulting public risk would be only 3×10^{-5} man-rem/RY.

Boron Dilution: This transient is caused by a CVCS malfunction which dilutes soluble boron in the reactor moderator. The reactivity insertion rate is very slow, on the order of 10^{-5}/second at the start and diminishing asymptotically to zero as the moderator becomes more dilute. Thus, the transient is also very slow, giving the operator as much as an hour or more to take action for a dilution event during startup. Because the power increase is slow, fuel failures due to PCI are not expected.

For a PWR core at BOC conditions, there is insufficient reactivity worth in the control rods to maintain the core subcritical with no soluble boron in the moderator. Thus, a reactor scram does not permanently terminate the transient; operator action is necessary to stop the dilution and re-borate the moderator. However, a reactor scram does give the operator more time to respond. In EPRI NP-801,[178] the frequency of boron dilution events was estimated to be 0.03 event/RY. Again, it was assumed that almost half of these events occur during startup.

As the event progresses, the operator (for whom credit was given for this slow transient) must fail to observe the transient and take no action (assume probability ≤ 0.10). The source range trip must fail (0.01 - 0.0001), the intermediate range trip must fail (0.01 - 0.0001) and the low setpoint power range trip must fail (0.0001). At this point, the estimated change in frequency is reduced to 1.5×10^{-11}/RY. Reactor power increases past 25% and thermal energy is dumped via the main condenser steam dump, the ADVs, and/or the steam generator safety valves, depending on plant conditions. Eventually, as reactor power increases to a value too great to be dissipated by these means, trip signals on pressurizer high pressure, pressurizer high water level, steam generator low-low water level, turbine trip (which functions as a 50% power trip as the P-9 permissive is reached), overtemperature ΔT, and several others may scram the reactor. (Fuel still has not been damaged.) However, even with no credit for these non-neutron-flux trips, a frequency of 1.5×10^{-11}/RY was estimated. Thus, this transient was not considered further.

(2) PWR - Turbine Trip

A turbine trip, normally sensed as either two out of three low autostop oil pressure signals or four out of four turbine stop valves closed, causes a reactor scram when the plant is operating above a preset power level (e.g., 10%). If a turbine trip occurs and this scram fails, steam pressure will rise in the secondary system. The atmospheric dump valves and steam generator safety valves will be available to limit the pressure rise, and the steam dump (which is usually in T_{avg} mode during power operation) will open and dump steam directly to the condenser. However, before these alternate energy sinks become available, the primary system will experience a rapid heat up. Expansion of the primary coolant will force coolant into the pressurizer, compressing the steam bubble. Reactor scram signals will be generated by the high pressurizer pressure, overtemperature ΔT and high pressurizer level signals, and the transient will

"turn around." Pressurizer spray will also turn on to limit the primary pressure transient, but it is likely that the PORVs will open.

This evaluation was restricted to W and CE plants. Upgraded anticipatory reactor trips on turbine trips were required of B&W plants by TMI Action Plan Item II.K.2(10) which was implemented under MPA F-28. The safety significance of this trip is two-fold: (1) the anticipatory trip increases the reliability of the entire RPS, thus decreasing the frequency of ATWS events; and (2) by preventing opening of a pressurizer PORV, the frequency of a small LOCA is also decreased. In EPRI NP-801,[178] the following transient frequencies involving a turbine trip are listed:

Turbine Trip	1.48/RY
Load Rejection	0.45/RY
Loss of Condenser Vacuum	0.12/RY
Loss of Circulating Water	0.07/RY
Total:	2.12/RY

The last two initiators will also disable the steam dump and, on plants with turbine-driven main feedwater pumps, cause a loss of feedwater. However, tripping of the main turbine is the first event to cause a reactor transient.

It was assumed that a PORV opens about half the time in these transients. Also, the probability that a PORV will fail to re-close was estimated to be 1% per actuation (WASH-1400,[16] Appendix V, §4.3.1). The S2 LOCA sequence is then a turbine trip transient (2.12/RY), failure of the anticipatory trip channels (10^{-2} - 10^{-4}), opening of a PORV (0.5), failure of the PORV to re-close (0.01), and failure of the operator to correctly diagnose the problem and close the PORV block valves (assumed to be 0.1). The change in S2 frequency was then 10^{-5}/RY.

The scram reliability is increased by the diversity of an anticipatory trip. However, placing TS on the anticipatory trip does not affect the common mode failure rate (CM) of the RPS. If the high pressurizer pressure, overtemperature ΔT, and high pressurizer level signals have failure rates of 0.0001/demand, and the imposition of TS reduces the turbine trip signal failure rate from 0.01 to 0.0001, the RPS failure rate is:

$(0.0001)^3(0.01)$ + CM without anticipatory trip TS
$(0.0001)^3(0.0001)$ + CM with anticipatory trip TS.

The change in RPS failure rate is 9.9×10^{-15}; the common mode contribution cancels out. This is negligible compared with the S2 sequences, therefore, it was not considered further.

The public risk associated with the S2 sequences was obtained by normalizing the WASH-1400[16] results (where an S2 frequency of 10^{-3}/RY was assumed) to a frequency of 10^{-5}/RY (see WASH-1400[16] Table V, 3-14):

Release Category	Normalized ΔS2 Frequency (/RY)	Consequence (man-rem)	ΔFR (Man-rem/RY)
PWR-1	1.0×10^{-9}	5.4×10^{6}	5.4×10^{-1}
PWR-2	3.0×10^{-9}	4.8×10^{6}	1.4×10^{-2}
PWR-3	3.0×10^{-8}	5.4×10^{6}	1.6×10^{-1}
PWR-4	3.0×10^{-9}	2.7×10^{6}	8.1×10^{-3}
PWR-5	3.0×10^{-9}	1.0×10^{6}	3.0×10^{-3}
PWR-6	2.0×10^{-8}	1.5×10^{5}	3.0×10^{-3}
PWR-7	2.0×10^{-7}	2.3×10^{3}	4.6×10^{-4}
Total:	2.6×10^{-7}		2.0×10^{-1}

(3) PWR - Low Steam Generator Level Coincident with Steam-Feed Mismatch

This anticipatory trip will scram the reactor on low steam generator water level coincident with steam flow greater than feedwater flow by a preset amount (usually 40% of rated). It is backed up by the low-low steam generator water level trip.

The initiating event here is a total loss of feedwater event in any steam generator. Partial loss of feedwater events or total loss of feedwater flow at reduced power levels may not produce sufficient mismatch between steam and feedwater flow to actuate the anticipatory trip; such events are also slower and early scram is not as important.

If all feedwater pumps are lost, the secondary side water temperature will rise because of the loss of the relatively cool feedwater, the heat transfer across the steam generator tubes is reduced and the primary side heats up. Simultaneously, the secondary water level decreases. The anticipatory trip signal will occur, and then the low-low steam generator level trip. The increasing primary temperature and resultant coolant swell will force more coolant into the pressurizer, compressing the steam bubble and causing an increase in primary system pressure. Reactor trip signals on overtemperature ΔT, high pressurizer pressure, and high pressurizer level will occur if the reactor has not already been scrammed, and the PORVs may open to limit the pressurizer pressure. The AFW system will also be initiated by the loss of main feedwater pumps or by low-low steam generator water level. If the AFW system fails and the steam generator tubes uncover, primary side temperature and pressure will rise more rapidly and the pressurizer safety valves will open. However, the probability of this event is not greatly affected by reliability of the anticipatory scram. Thus, it was not considered in this evaluation.

As in the turbine trip transient evaluated previously, the anticipatory trip decreases the probability of an ATWS event and also helps prevent a pressurizer PORV from opening, thus decreasing the frequency of a small LOCA. The transients that will cause a loss of feedwater were taken from EPRI NP-801[178] and are listed in Table 3.90-1.

As in the turbine trip transient, it was assumed that a PORV opens half the time if the anticipatory trip fails and that the PORV fails to re-close 1% of the time. The S2 frequency is then 2.28 transients/RY

multiplied by the change in probability of anticipatory trip failure (0.01 - 0.0001), the probability of PORV opening (0.5), the probability of failure of the PORV to re-close (0.01), and the probability of operator failure to close the block valve (0.1). The result of 10^{-5}/RY is the same as the turbine trip case and thus the risk figures are the same: 2.6×10^{-7} core-melt/RY, 0.2 man-rem/RY.

Table 3.90-1

Loss of feedwater (one loop)	0.99/RY
Loss of feedwater (all loops)	0.08/RY
Feedwater instability (operator error)	0.66/RY
Feedwater instability (mechanical problem)	0.50/RY
Loss of one condensate pump	0.05/RY
Loss of all condensate pumps	0.00/RY
Total:	2.28/RY

The change in the probability of RPS failure is given by the change in anticipatory trip failure (0.0099) multiplied by the non-common mode failure probabilities of the trips on low-low steam generator level, over-temperature ΔT, high pressurizer pressure, and high pressurizer level, each of which is 0.0001. The resulting change in ATWS frequency is on the order of 2.3×10^{-18}/RY which is negligible compared to the S2 LOCA considerations above.

(4) BWR - High Neutron Flux, Source Range.

As in the PWR case, BWR licensing basis transient calculations for startup events do not take credit for the source range monitor (SRM) and intermediate range monitor (IRM) trip setpoints, but instead assume that the reactor is scrammed by the startup mode setpoint of the average power range monitor (APRM) system, usually 15% of rated power. Unlike the PWRs, the IRM scram setpoints are already in the TS; the SRM scram setpoints are not required (although the monitoring function of the SRM is addressed). Moreover, it is common (if not universal) practice to disable the SRM scram inputs with shorting links after the plant's initial core loading is complete. Thus, the SRM scram generally has a failure probability of 1.

However, the SRM scram, at its usual setpoint of 5×10^5 counts/second, is generally not the first scram to occur during a startup transient or accident. The reason is that, in a BWR, the IRM rod block and scram setpoints are defined as percentages of full scale for each IRM range, and the IRM ranges cover five decades. The SRMs and IRMs must overlap. SRMs are interlocked such that they cannot be withdrawn unless the IRMs are on Range 3 or above. If the IRMs are on Range 1 (and if they are not, a rod block on IRM Downscale will prevent rod withdrawal), the IRM scram will occur virtually simultaneously with or (more likely) prior to the SRM scram. Therefore, the SRM scram will not reduce plant upset; it will only somewhat increase the reliability of the RPS. The events of interest are the rod drop accident (RDA) and the short period transient. (Because of the individual rod pulls used in a BWR, there is no analog to the PWR rod bank withdrawal error.)

RDAs and probabilities are discussed in an RDA Statistical Analysis.[7] The basic sequence starts with 2×10^{3} rod withdrawals/RY in the startup range. To get an RDA, a rod must disconnect (maximum 2×10^{-4}), become stuck (maximum 10^{-2}), and become unstuck and drop at the appropriate time (maximum 6×10^{-3}). This does not imply that the rod is out of sequence or will lead to high worth. This translates into 2.4×10^{-5} RDA/RY requiring a reactor scram. The maximum improvement the SRM scram channel can make is $(1 - 0.0001)(0.0001)^{2}$ or 10^{-8}. The ΔF involved is then 2.4×10^{-13} event/RY; this is a negligible frequency. Even if such an event ruptured both the vessel and containment and completely melted the entire core under the worst conditions (i.e., BWR-2 release), the maximum public risk would be 1.7 micro-man-rem/RY.

Short period events are more common. As was mentioned earlier, IE Bulletin No. 79-12[6] and IE Circular No. 77-07[5] list 5 such events in 155 BWR-years, a frequency of 3.2×10^{-2}/RY. These events will happen with the IRM channels set on their first range and the SRM scram, if functional, would not anticipate other scrams but instead would provide a backup to the IRM scram. Rod blocks are largely ineffective here since the high incremental rod worth is tied up in one 6-inch notch.

Historically, these events have occurred just at the point of criticality. Since the operator is using the period meters to detect criticality, a short period event is easily noticed and these events have generally been terminated by operator action, not by the RPS. If the operator does not intervene (assuming a probability of 0.1) and the IRM and APRM scrams fail (probability = 10^{-8}), the reactor core would ascend into the power range where the usual reactivity coefficients would turn the transient around. The only consequence would be some cladding failure due to PCI. The consequences to the public can be bounded by those of a licensing basis RDA in which 770 fuel rods fail. These consequences are 0.007 man-rem/event. Thus, the net risk from short period events, even with no credit for the SRM scram is, at most, $(3.2 \times 10^{-2}\text{/RY})(0.10)(10^{-8})$(0.007 man-rem) = 2.2×10^{-13} man-rem/RY. Again, this is negligible.

Based on the calculations in (1), (2), and (3) above, the core-melt frequency estimate was $[(5.5 \times 10^{-15}) + (2.6 \times 10^{-7}) + (2.6 \times 10^{-7})]$/RY or 5.2×10^{-7}/RY. The public risk reduction was estimated to be $[(5.5 \times 10^{-9}) + (2.3 \times 10^{-2}) + (4 \times 10^{-8}) + (2 \times 10^{-1}) + (0.2)]$ man-rem/RY or 0.42 man-rem/RY.

Approximately 20 PWRs would be affected by the proposed action. Action on BWRs was unlikely to be approved since the potential safety gain from the SRM trip was so small.) Assuming an average remaining life of 20 years for the affected plants, the total remaining operating life was 400 RY. Thus, the total public risk reduction associated with this issue was approximately 170 man-rem.

Cost Estimate

Industry Cost: TS on anticipatory trips would probably be similar to those in the PWR STS. This would involve the following for Source Range Neutron Flux: (1) channel checks every shift except during power operation; (2) calibration every refueling outage; and (3) analog operational tests monthly and prior to startups. For Intermediate Range Neutron Flux, this would include: (1) channel checks every shift while in startup; (2) calibration every refueling outage; and (3) analog

operational test monthly and prior to startup. For steam generator low level/steam-feed mismatch this would include: (1) calibration every refueling outage; and (2) analog operational tests monthly. For turbine trip, this would include trip actuation device tests prior to startup. It was assumed that there would be 10 startups/year, 2 months refueling outage every 18 months, 5 days to go from cold shutdown to power, 10 minutes for channel checks, 4 hours for calibrations, and 1 hour for analog and trip device tests. Based on a cost of $100,000/man-year, the industry cost was estimated to be $4,000/RY or $1.6M for the affected plants.

NRC Cost: It was assumed that 2 man-years of effort would be needed to develop and carry out an action plan for the issue, including developing CRGR packages, etc., and that monitoring licensee compliance would take 8 hours/RY of inspection time.

Total Cost: The total cost of implementing the possible solution to this issue was estimated to be $98,000/reactor or approximately $2M for all affected reactors.

Value/Impact Assessment

Based on a public risk reduction of 170 man-rem and a cost of $2M, the value/impact score was given by:

$$S = \frac{170 \text{ man-rem}}{\$2M}$$

$$= 85 \text{ man-rem}/\$M$$

Other Considerations

The above calculations did not include credit for averted cleanup costs to the licensee. It should be remembered that avoidance of PORV opening (and secondary side safety valve opening) is a major reason for installing anticipatory trips. Inclusion of averted cleanup costs as a credit against the cost to the licensee could significantly raise the priority score. Moreover, the occupational man-rem averted by preventing PORV opening (and possible rupture of the pressurizer relief tank rupture disc) might also be significant.

CONCLUSION

Based on the low risk reduction potential and low value/impact score, this issue was given a LOW priority ranking (See Appendix C). In NUREG/CR-5382,[1563] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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ISSUE 100: ONCE-THROUGH STEAM GENERATOR LEVEL

DESCRIPTION

Historical Background

Once-through steam generators (OTSGs) are a feature unique to B&W reactor designs. Main feedwater is injected from a header, located at approximately mid-elevation of the OTSG, into an annular downcomer region. As the feedwater is sprayed into the downcomer, the condensing action of the relatively cold (455°F) feedwater draws steam from the tube bundle through the aspirator ports in the inner shroud. This steam then heats the feedwater rapidly to saturation temperature (about 535°F) preventing thermal shocking of the shell.

In 1984, Crystal River 3 submitted a TS change request to raise the operating water level limit of the OTSGs to 100% of the operating range (which is six inches above the aspirator ports). Since most operating B&W plants did not have an upper OTSG level limit in their TS, the TS change was requested to give Crystal River 3 the same operational flexibility. This change request raised a concern regarding operating OTSGs with the water level above the aspirator ports.[1380]

Safety Significance

Permitting operation with a higher water level limit would allow less time for corrective operator action, if there were a transient that involved an increase in feedwater flow to one or more steam generators. If the increased feedwater flow continues (e.g., if the steam generator high-level detection system has failed, feedwater control valves have failed, or the main feedwater pump fails to trip), the steam generator water level may exceed the aspirator port level, thus preventing the preheating of the feedwater. If the increased thermal stresses on the tubes or shell wall are excessive, an SGTR or steam generator shell failure accident could occur creating a LOCA or an initial steam-side break in the case of a shell failure. This issue affected all B&W PWRs.

Possible Solution

A possible solution entailed a detailed generic analysis to determine whether operating OTSGs at levels near or above the aspirator ports would introduce a significant safety problem at B&W plants. New plant-specific TS limits would have to be developed to preclude plant operations if OTSG water levels exceed a pre-set maximum level.

PRIORITY DETERMINATION

Assumptions

All ten of the operating or proposed B&W PWRs were considered in this analysis and Oconee 3 was selected as the reference plant; TMI-2 was not included because it was shut down indefinitely. The average remaining operating life of the 10 B&W plants considered was 28.2 years, based on the original 40-year license. However,

it was assumed that 75% of these plants will have their licenses extended for an additional 20 years and, therefore, the total remaining operating life of these plants was assumed to be 432 RY.

Frequency Estimate

The initiating transient of concern involved an increase in feedwater flow to one or more loops. If the increased feedwater flow continues, e.g., if the steam generator high-level detection system fails, feedwater control valves fail, or the main feedwater pump fails to trip, the steam generator water level may exceed the aspirator port level. The resultant backflow of feedwater through the aspirator ports may then result in a SGTR or steam generator shell failure accident. The accident sequence developed[64] by PNL to model the effect of the proposed solution produced the following results:

(1) The average frequency of increased feedwater flow for B&W plants was developed in Section 1.0 of NUREG/CR-3862[1186] to be 0.13 transient/RY;

(2) The probability of failure on demand to reduce main feedwater flow (product of undetected failure of steam generator high-level trip and operator failure to terminate the overfeed event) was (0.047)(0.7) = 0.033;

(3) The probability of an SGTR, given an overfill event, was 0.027;

(4) The probability of steam generator shell failure (SGSF), given an overfill event, was 0.027;

(5) The sum of the conditional probabilities of SGTR and SGSF was 0.054;

(6) The probability of a failure on demand to mitigate the SGTR or SGSF (estimated from core-melt frequency from SGTR sequences divided by the SGTR initiating event frequency) was $(2.7 \times 10^{-6})/(8.6 \times 10^{-3}) = 3.14 \times 10^{-4}$;

(7) The resulting base case accident sequence frequency was estimated to be $(0.13/RY)(0.033)(0.054)(3.14 \times 10^{-4}) = 7.27 \times 10^{-8}/RY$.

The effects of an enhanced testing and inspection program for steam generator level instrumentation and feedwater controls was assumed to reduce the conditional probablity of failure to reduce main feedwater flow, given a feedwater overfeed event, to 0.011/demand. Therefore, the adjusted case accident frequency was $(0.011/0.033)(7.27 \times 10^{-8})/RY = 2.43 \times 10^{-8}/RY$. Thus, the reduction in core-melt frequency was estimated to be $[(7.27 \times 10^{-8})/RY - (2.43 \times 10^{-8})/RY] = 4.8 \times 10^{-8}/RY$.

Consequence Estimate

Containment failure probabilities and corresponding dose consequences were then combined with the accident frequencies to calculate public risk. The base case and adjusted case risk was calculated[64] by PNL to be 0.2 and 0.066 man-rem/RY, respectively. Based on a total operating life of 432 RY, the potential risk reduction for all affected plants was determined to be 56 man-rem.

Cost Estimate

Industry Cost: Licensees would have to prepare safety analyses to support revising plant-specific TS. The total cost for these safety analyses and TS preparation was estimated to be $4.1M; operation and maintenance costs associated with increased inspection and testing were estimated to be $4.3M. Thus, the total industry cost associated with the possible solution was estimated to be $8.4M.

NRC Cost: The total cost for development of a solution, support of implementation, and review of operation and maintenance was estimated to be $320,000, $91,000, and $490,000, respectively. Thus, the total NRC cost for the possible solution was estimated to be $0.9M.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $9.3M.

Value/Impact Assessment

Based on a potential risk reduction of 56 man-rem and a total cost of $9.3M for a possible solution, the value/impact score was given by:

$$S = \frac{56 \text{ man-rem}}{\$9.3M}$$

$$= 6 \text{ man-rem/\$M}$$

Other Considerations

The central concern in this issue was that operating OTSGs at a high water level could allow feedwater back through the aspirator ports onto steam generator tubes potentially affecting tube integrity. The effects on steam generator tube integrity from this particular event, however, were within the steam generator design bases. A partial list of these design bases is summarized below:

- 15,000 cycles of adding 40°F feedwater at 875 gpm when at hot standby conditions (normal condition)
- 500 cycles of adding 40°F feedwater at 875 gpm during loading conditions (normal condition)
- 500 cycles of adding 100°F feedwater at 875 gpm during loading conditions (normal condition)
- 7 cycles of adding 40°F feedwater at 1750 gpm during a steam line break (faulted condition)
- 280 cycles of adding 40°F feedwater at 1750 gpm with the flow initiated 30 seconds after a loss of main feedwater (faulted condition).

Given that main feedwater is normally about 455°F during loading conditions, the thermal effects of adding 40°F emergency feedwater would be substantially greater than those of spilling main feedwater through the aspirator ports onto the tubes. In addition, the aspirator ports are located near the middle of the tube sheet, which is a less stressed position than the location of the emergency feedwater

nozzle, which is higher in the OTSG. This further indicated that the steam generator tubes were likely to withstand 455°F main feedwater introduced through the aspirator ports onto the tubes.

CONCLUSION

OTSGs are designed to withstand over 15,000 cycles of injection of 40°F emergency feedwater. The consequences of operating with a water level above the aspirator ports (which would introduce 455°F water) are less severe than that assumed in this analysis and are within the OTSG design limits. The possible solution did not produce a significant reduction in public risk and the value/impact score was small. Therefore, this issue was DROPPED from further pursuit (See Appendix C). Consideration of a 20-year license renewal period did not change the priority of the issue.[1564]

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ISSUE 105: INTERFACING SYSTEMS LOCA AT LWRs

DESCRIPTION

Historical Background

Issue B-63, which was resolved and implemented as MPA B-45, required leak-testing of the check valves that isolate those low pressure systems that are connected to the RCS outside the containment. However, except for Oyster Creek and Nine Mile Point, these low pressure systems in BWRs are isolated with check valves that have actuators that are used to test the operability of the valves. This operability test was considered sufficient to assure the integrity of the pressure isolation function and leak-testing of PIVs in BWRs was not required. However, beginning in 1980, the BWR STS Section 3.4.6.2 required the leak-testing of all RCS PIVs at least once every 18 months and after any work on a valve. This STS requirement was also applied to operating plants as they submitted their IST programs for review.

BWR operating experience indicated that the isolation valves between the RCS and low pressure interfacing systems (including related test and maintenance requirements) may not adequately protect against overpressurization of low pressure systems. There were three reported failures of the boundary between the RCS and low pressure injection systems in approximately 200 BWR-years of operation.[762] Two of the events (Vermont Yankee, 12/12/75, and Browns Ferry 1, 8/14/84) were the result of maintenance errors which left the testable isolation check valve in the open position. The third (Pilgrim, 9/29/83) was the result of personnel errors (improper combination of surveillance tests) and a stuck-open failure of an isolation check valve. In all three cases, there was a degradation of the PIVs due to personnel errors. None of these plants were required to leak test PIVs.

This issue, which is limited to PIVs in BWRs, is related to Issue 96 which addressed the failure of the PIVs between the RCS and the RHR system in PWRs.

Safety Significance

Overpressurization of low pressure piping systems due to RCS boundary isolation failure could result in rupture of the low pressure piping. This, if combined with failures in the ECI and/or the DHR systems, would result in a core-melt accident with an energetic release outside the containment building causing significant offsite radiation release. The STS require leak-testing of PIVs at least after every refueling and in some cases more frequently. Therefore, this issue applies to BWRs licensed before 1980.

Operating BWRs which have RCS/RHR system interface configurations similar to Hatch Unit 2 have been identified and include: Duane Arnold, Brunswick 1 and 2, Cooper, Dresden 2 and 3, Hatch 1, Fitzpatrick, Monticello, Peach Bottom 2 and 3, Pilgrim, and Quad Cities 1 and 2.[761] Browns Ferry 1 also experienced a similar isolation boundary problem. Therefore, the list of affected plants utilized in this analysis also includes BWR 3 and 4 operating plants (i.e., Millstone, Browns Ferry 1, 2 and 3, and Vermont Yankee). Therefore, the total number of potentially

affected operating BWRs considered in this analysis is 20 with an average remaining life of 26 years.

Possible Solution

For the purpose of this evaluation, it was assumed that the frequency of low pressure system overpressurization events will be reduced by instigating a more rigorous revised inspection program (follow specific test and post-maintenance procedures, conduct surveillance tests one at a time, performing leak tests after operability demonstrations or flow tests) and making minor hardware modifications such as modifications to testable check valve air supply lines to precluding interchanging the lines (different threads, different size connectors, color coding, and labeling). Major system hardware changes were not anticipated.

Resolution of the issue was assumed to result in improved surveillance, maintenance, and test procedures, and minor modifications to make the air actuation system for testable check valves foolproof.

PRIORITY DETERMINATION

Frequency Estimate

Since this issue affected only BWRs, the Browns Ferry, Unit 1, IREP[367] PRA was used in the estimation of public risk reduction.[64] The general approach was to use available historical data for failure of the high pressure/low pressure isolation boundary and a probability estimate for piping failure due to overpressurization to modify the appropriate LOCA sequences from the Browns Ferry PRA. These modified appropriate (affected) LOCA sequences are then assumed to represent the current (base case) level of plant risk associated with this issue. Specifically, the event L_s (large-break LOCA from 0.3 to 4.3 ft^2) from the Browns Ferry PRA was redefined as the product of the probability of failure of the high pressure/low pressure isolation boundary and the probability of failure of the low pressure piping as a result of overpressurization.

From the historical data (3 isolation boundary failures in about 200 BWR plant-years), a probability of failure of the isolation barrier of 1.5×10^{-2}/RY was estimated. Analysis of the low pressure piping revealed that the hoop stress in the low pressure piping would not be expected to exceed the yield value for the piping. Thus, failure of the low pressure piping was assumed to be likely only in the presence of a significant crack in the piping. Using data available on IGSCC, estimates of the number of piping welds in the low pressure piping systems, and estimates of the distribution of depth of cracks (percent of wall) from existing pipe crack data, PNL estimated the conditional probability of an intersystem LOCA, via the pipe cracking scenario, of 10^{-1}/event given an over-pressurization of the low pressure piping. This resulted in a new estimate of L_s of 1.5×10^{-3}/RY, as opposed to the value of L_s derived in the Browns Ferry PRA (3×10^{-3}/RY).

In NUREG-0677,[763] a probability of BWR intersystem LOCA (ISLOCA) of 6.2×10^{-4}/RY was calculated; no contribution from maintenance and operator errors was included. The BWR ISLOCA frequency derived for this analysis (1.5×10^{-3}/RY), which was based on previous LERs, was dominated by operator and maintenance errors and appeared to be an expected value when compared to the value derived in NUREG-0677.[763] When this new value of L_s (1.5×10^{-3}/RY) was inserted into the

affected core-melt minimal cutsets in the Browns Ferry PRA, a base case core-melt frequency due to isolation boundary failures of 6.31×10^{-6}/RY was calculated.

Consequence Estimate

The effect of a core-melt accident resulting in direct releases outside containment was assumed to be equivalent to a BWR Release Category 2. When the dose conversion factor for BWR Category 2 events (7.1×10^{6} man-rem/event) was multiplied by the base case core-melt frequency, a public risk of 44.7 man-rem/RY resulted.

Implementation of the possible solution to this issue was assumed to reduce the core-melt frequency and public risk due to overpressurization and failure of low pressure systems connecting to the RCS to those values calculated from the Browns Ferry PRA, i.e., 1.22×10^{-10} event/RY and 8.66×10^{-4} man-rem/RY, respectively. Therefore, implementation of the possible solution was estimated to result in a reduction in core-melt frequency of 6.3×10^{-6}/RY and a reduction of public risk of 44.7 man-rem/RY. The total public risk reduction for the 20 affected plants over their 26-year average remaining lifetime was calculated to be 2.3×10^{4} man-rem.

Cost Estimate

Industry Cost: Implementation of the possible solution was estimated to require about 4 man-weeks/plant for revision of surveillance, maintenance, and test procedures, and installation of foolproof features on the testable check valve actuation system, plus about $2,500/plant for materials (connectors, tags, etc.). Thus, an implementation cost of $220,000 was estimated. Increased surveillance testing, reduction of allowable concurrent testing and improved post-maintenance inspection procedures were estimated to increase plant maintenance and surveillance efforts by 40 man-hours/RY. Thus, the present worth of the increase in plant operation and maintenance costs for the 20 affected plants over their remaining lifetime was calculated to be about $650,000. Total industry cost for resolution (and implementation) of this issue was therefore estimated to be about $875,000.

NRC Cost: It was assumed that resolution of this issue will require 5 staff-months of technical effort and technical contract support for a more precise PRA, for a total resolution cost of about $100,000. It was assumed that NRC staff review of licensee implementation of the assumed solution would require 5 staff-weeks/plant for a cost of about $230,000. Resident inspector surveillance of site actions emanating from the resolution was estimated to require 0.5 staff-week/RY for a present worth of about $325,000 over the remaining lifetime of the 20 affected BWRs. The total present worth NRC cost for this issue was thus estimated to be about $650,000.

Total Cost: The total NRC and industry cost for resolution and implementation of the possible solution was estimated to be approximately $1.5M.

Value/Impact Assessment

Based on a potential public risk reduction of 2.3×10^{4} man-rem and a total cost of $1.5M, the value/impact score was given by:

$$S = \frac{2.3 \times 10^4 \text{ man-rem}}{\$1.5M}$$

$$= 15{,}000 \text{ man-rem/\$M}$$

Other Considerations

(1) The probability of ISLOCA may well be greater than that calculated above based on piping failure. Other components in low pressure systems, such as pump seals, heat exchanger tubes, thermocouple wells, etc., would also be subject to overpressure failures. Also, while not explicitly considered in calculating the estimated core-melt frequency and risk, the failure of all low pressure systems due to overpressure resulting from failure of PIVs contributes further to the risk. Although the risk from other interfaces was not calculated, the evaluation of Issue 96 showed that the risk from failures of the valves isolating the RHR system in a PWR was at least an order of magnitude less than the risk calculated for this issue. The failure of PIVs in a BWR RHR system would affect only part of the ECCS system, rather than all as in a PWR. Therefore, the risk in a BWR would be even less than in a PWR.

(2) ISLOCA releases in the auxiliary building would also be expected to present an additional common mode failure mechanism for failure of redundant safety systems located in the auxiliary building. These considerations were not included in this analysis. However, had they been included, the estimates of frequency for ISLOCA and resultant core-melt would have been greater. For this reason, the priority reached on the basis of the simplified analysis performed for this issue was conservative.

(3) A relatively small total increase in ORE (530 man-rem) was calculated due to assumed increases in surveillance and post-maintenance inspections. This calculation assumed 40 man-hours/RY for increased maintenance in a 25 millirem/hr field at the 20 affected BWRs for their remaining lifetime. Reduction in the estimated frequency of core-melt and non-core-melt intersystem LOCA which might be attained was calculated to result in a total averted ORE of 215 man-rem: 65 man-rem due to cleanup of a core-melt event and 150 man-rem due to cleanup of non-core-melt ISLOCAs. Both the increased ORE and the averted operator exposure were insignificant in comparison to the calculated public risk reduction of 2.3×10^4 man-rem and did not alter the priority indicated by the value/impact assessment.

(4) At an estimated industry cleanup and replacement power cost of $1.65 Billion for a core-melt accident and $720M for a successfully-mitigated LOCA, the frequency reduction of core-melt and non-core-melt ISLOCA estimated for resolution of this issue would result in an averted accident cost savings with a present worth of about $2.7M. This exceeded the total expected NRC and industry cost and supported resolution of the issue.

CONCLUSION

This issue was given a high priority ranking (See Appendix C) and resolution was pursued. In resolving the issue, the staff conducted analyses of units representative of all NSSS vendors and considered: (1) human errors, both as

initiators and during recovery operations; (2) component fragilities, to determine likely low pressure system break locations; and (3) the post-ISLOCA auxiliary building environment, to determine the survivability of recovery equipment. These analyses were documented in NUREG/CR-5604,[1494] NUREG/CR-5744,[1495] NUREG/CR-5745,[1496] NUREG/CR-5603,[1497] NUREG/CR-5862,[1498] and NUREG/CR-5928.[1499] It was concluded that the units studied posed little risk from ISLOCA.

In addition to the above analyses, previous PWR ISLOCA studies[1500] were reexamined with data updated to include the seven years of operating experience that had accrued since the initial analyses were undertaken. None of the studies supported generic requirements for PWRs, whether on absolute risk reduction or cost-beneficial bases.[1501] The study[1499] of ISLOCA at a BWR confirmed past PRA studies which generally indicated little risk contribution from ISLOCA sequences.

The staff found that ISLOCAs at PWRs were plant-specific in nature; however, the ongoing IPE program[1222] includes licensee analysis of ISLOCA sequences. With respect to future applicants, a draft SRP[11] Section covering design review of systems interfacing with the RCS in ALWRs was provided[1503] to NRR for information and use as appropriate. Supplement 1 to Information Notice 92-36[1502] was issued to share insights from the ISLOCA program and to inform licensees of the availability of material useful for IPE ISLOCA analyses not yet completed, or as a check on analyses already completed. Thus, this issue was RESOLVED and no new requirements were established.[1504] Consideration of a license renewal period of 20 years for the affected plants would not change the resolution.[1501,1564]

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1504. Memorandum for J. Taylor from E. Beckjord, "Technical Resolution of Generic Issue 105 (GI-105) 'Interfacing Systems Loss of Coolant Accident (ISLOCA) in LWRs,'" June 3, 1993.

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ISSUE 106: PIPING AND THE USE OF HIGHLY COMBUSTIBLE GASES IN VITAL AREAS

DESCRIPTION

Historical Background

Combustible gases such as H_2, propane, and acetylene are used during normal operations of nuclear power plants in limited quantities and for relatively short periods of time. H_2, the most prevalent of these gases in nuclear plants, is used as a coolant for electric generators in both BWRs and PWRs, for the control of reactor water chemistry and waste gas disposal in PWRs, and in the volume control tank (VCT) which is usually located in the auxiliary building of PWRs. It is stored as high pressure gas in vessels and is supplied to the various systems in the auxiliary building through standard piping, usually 3/4-inch in diameter. As a result, H_2 piping is field-run and its location is plant-specific.

The concern in this issue is that leaks or breaks in the H_2 piping and supply system could result in the accumulation of a combustible or explosive mixture of air and H_2 within the auxiliary building. Inasmuch as the auxiliary building is a safety-related structure which houses most of the components of the safety-related systems of a plant, the accumulation of combustible or explosive mixtures of gas represents a threat to plant safety by virtue of the potential disablement of safety-related equipment, in the event that the combustible gases are inadvertently ignited. H_2 detectors can signal the presence and accumulation of gas, but these are not qualified as safety-grade equipment and do not have an emergency power source. Thus, they are not regarded as sufficient protection against the development of H_2 leakage and subsequent uncontrolled combustion or explosion. This issue primarily affected operating reactors licensed prior to the issuance of SRP[11] Section 9.5-1, "Fire Protection," which addresses the safe use of combustible gases on site.

This issue was identified in NUREG-0705[44] and is related to Issue 136, "Storage and Use of Large Quantities of Cryogenic Combustibles on Site." Whereas Issue 106 addressed the normal process system use of relatively small amounts of combustible gases on site, Issue 136 addressed the considerably greater hazards of much greater amounts of combustible materials introduced by new needs at sites, i.e., solid waste processing and BWR H_2 water chemistry control and the unique hazards associated with the transport and storage of large quantities of combustibles on site in a cryogenic liquid state.

Safety Significance

The auxiliary building is a safety-related structure housing safety-related system components. Inasmuch as the most frequently used combustible gas (H_2) is piped into this building for use in the VCT, there is the potential for leakage and the inadvertent ignition of the gas. The ensuing combustion or explosion can cause damage or failure of safety-related equipment, thereby contributing to a possibly significant increase in the core-melt probability of the plant.

Possible Solution

In the event of a piping system break or large leak, large releases of combustible gas and the accumulation of combustible or explosive mixtures in air can be prevented by the installation of excess-flow check valves located close to the source of the combustible gas. SRP[11] Section 9.5-1 recommends the use of excess-flow check valves. Other measures are needed to reduce the frequency of, or cause of, combustible gas accumulation accidents from such events as valve malfunctions or leaks, connection or fitting leaks, operations errors, material failures, etc. Plants licensed in accordance with the guidelines of SRP[11] Section 9.5-1 were assumed to be not affected by this issue; however, the backfitting of excess-flow check valves at all plants not licensed in accordance with SRP[11] 9.5-1 plants was assumed.

Excess-flow check valves were an effective "fix" for piping system breaks, but other fixes, such as installation or upgrading of H_2 detection systems, design changes, procedural changes, etc., will be required for other types of accidental releases. The risk and cost analyses performed for the installation of excess-flow check valves as a fix were extrapolated to develop a proper perspective.

PRIORITY DETERMINATION

Assumptions

It was assumed that, of all the combustible gases routinely used in a nuclear power plant, the most significant safety concern was associated with the use of H_2. Unlike most other gases used in small quantities at nuclear power plants, H_2 is used almost continuously while most other gases are used intermittently and, most likely, in the presence of trained personnel such as during welding operations. H_2 leaks could continue unnoticed as a result of leaks or pipe breaks that go undetected for a sufficient time to accumulate a combustible mixture. It was assumed that H_2 detectors were either not provided (as was the case in an event at Vogtle)[103] or were inoperative. In addition, it was assumed that operating plants licensed prior to the issuance of SRP[11] Section 9.5-1 did not have excess-flow check valves in place. This latter assumption was a conservative element in this analysis because it was likely that some of the plants licensed prior to SRP[11] Section 9.5-1 may have already had excess-flow check valves in place.

The auxiliary building is a safety-related structure that contains most of the components of the safety systems of a plant. However, the design of this structure and the location of safety-related components within the structure are plant-specific. In addition, location of the H_2 source and, in particular, the H_2 field-run piping layout are also plant-specific. In view of this, it was not possible to identify a particular damage scenario that represented a bounding sequence for the purposes of a generic analysis. Therefore, a reasonable but not necessarily bounding damage scenario was assumed in order to evaluate this issue. This scenario entailed the assumption of an H_2 piping system leak or break, the accumulation of a combustible mixture within a room or space containing safety-related equipment, an ignition source, and damage contained within that room or space.

A PNL analysis[64] of this issue based on a pipe break was extrapolated to estimate the frequency of all events that might result in the release and accumulation of

combustible gases in the auxiliary building. It was assumed that the pipe break frequency (for ¾" pipe) may be obtained from WASH-1400,[16] but that the probability of the accumulation of a combustible mixture, the probability of the availability of an ignition source, and the probability of total demolition of the safety-related redundant equipment are 1 in each instance. This latter assumption was conservative.

The scenario that was selected as a reasonable one for this analysis was the loss of both RHR heat exchangers (complete loss of heat sink). Resolution of this issue would affect operating plants using H_2 and not already in compliance with SRP[11] Section 9.5-1 with respect to H_2 gas piping. Specifically, resolution was anticipated to include all operating PWRs. Therefore, the number of affected plants was 47 PWRs with an average remaining lifetime of about 27.7 years.

Frequency Estimate

H_2 piping is standard piping generally thought to be ¾" in diameter. Based on the results of WASH-1400[16] (Tables III 2-1, 2-2), the pipe break frequency for piping less than 3" in diameter was 10^{-9}/hour per section. In general, it was assumed that the H_2 piping in nuclear plants is comprised of about 25 sections. With 8,760 hours/year and an assumed plant utilization factor of 70%, the frequency of H_2 release due to pipe break (f_p) was estimated to be:

$$(10^{-9})(25 \text{ sections})(8760 \text{ hours/year})(0.7) = (1.5)(10^{-4}) \text{ pipe breaks/RY}$$

A review of 96 H_2 accidents by NASA[1030] indicated that about 52% could have been attributed to causes that relate to use of H_2 in a gaseous state and about 48% to causes that relate to the use of H_2 in its liquid (cryogenic) state; only about 2% was attributed to piping breaks. Therefore, it was assumed that an H_2 accident from a gaseous state cause was (52% ÷ 2%) or 26 times more likely to occur than an H_2 accident due to a pipe break. The probability (P) of an H_2 release (leak) was given by:

$$\begin{aligned} P &= (26)(\text{Probability of Pipe Break}) \\ &= (26)(1.5 \times 10^{-4}) \\ &= 3.9 \times 10^{-3} \end{aligned}$$

The probability of failing both RHR heat exchangers, f(RHR), is the product of the probability of an H_2 leak, the probability of obtaining a combustible mixture, the probability of ignition, and the probability of being in the blast zone. Thus, $f(RHR) = (3.9 \times 10^{-3})(1)(1)(1) = 3.9 \times 10^{-3}$.

When both trains of the RHR system are inoperable, the TS require plants to proceed to the hot shutdown condition within 12 hours; this requirement was modeled in this analysis as a T3 (PWR) transient. Therefore, an H_2 explosion was modeled as an additional initiating transient (with a frequency of 3.9×10^{-3} /year as calculated above). All other initiating transients and LOCA parameters were scaled by (12/8,760 hours/RY) in order to model the occurrence of other random initiators during the 12 hours that the reactor is proceeding to hot shutdown. Finally, using the Oconee 3 PRA as representative of all PWRs, the RHR heat exchangers were modeled as inoperative by setting their representative system unavailabilities to 1. The Oconee PRA was then altered to incorporate the modified initiating event frequencies and the RHR systems unavailability in the

affected minimal cut sets for each affected accident sequence. All affected Boolean equations were solved to calculate new core-melt frequencies for all containment failure modes and the affected core-melt frequencies were summed for each of the 7 distinct PWR core-melt categories. Public risk was then determined by summing the products of core-melt frequency and their respective release category dose factor for each release category.

The analysis was repeated for a period of 96 hours (4 days) as an approximation of the time necessary to achieve cold shutdown by alternate means such as feed-and-bleed. Based on these details, the following core-melt frequency results were calculated:

PWR Base Case	$= 5.46 \times 10^{-6}$/RY
Adjusted Case	$= 2.26 \times 10^{-7}$/RY
Reduction in Core-melt Frequency	$= 5.20 \times 10^{-6}$/RY

Consequence Estimate

For the time required to come to hot shutdown (12 hours), the results of a PNL analysis[64] indicated that resolution of this issue would result in a risk reduction of 8.8 man-rem/RY for PWRs. The total public risk reduction was estimated to be approximately 11,500 man-rem. The estimated occupational risk reduction due to accident avoidance was approximately 135 man-rem.

Cost Estimate

Industry Cost: The cost of installing excess-flow check valves in the H_2 lines outside of the safety-related areas was estimated.[64] It was assumed that these valves would be installed during scheduled reactor shutdown periods so that there would be no additional power replacement cost incurred. Based on two vendor quotations, the average cost of one excess-flow valve was approximately $870. The costs for the implementation, maintenance, and operation of the excess-flow check valve "fix" was detailed as follows:

(a) Implementation

Hardware Design and Review	= 2 days
Procurement	= 1 day
Pre-Installation Check	= 0.5 hour/valve
Installation	= 2 days/valve [1 man-day/valve (welder), 1 man-day/valve (fitter)]
Post-Installation Check	= 1.5 hours/valve
Documentation	= 0.5 day
Total Labor Time (PWR)	= 3.5 days + 2.25 days/valve = 8 days
Labor Cost (PWR)	= (8 days)($2,270/man-week)/(5 days/man-week) = $3,632/plant

(b) Equipment

Valve Cost (PWR)	= (2)($870) = $1,740/plant

The total implementation cost/plant was $(3,632 + 1,740) or $5,372; for all 47 affected plants, this cost was approximately $255,000.

Operation and maintenance would include a semi-annual check of the installation to ensure that the valve shaft was not "frozen" and replacement of the valve diaphragm as needed; the frequency of this replacement would depend upon the valve environment. For this analysis, the diaphragm was assumed to require replacement every 7 years with an associated labor requirement of 0.5 man-day.

(a) Labor for Maintenance and Operation

Semi-annual Check = 2 hours/valves

Diaphragm replacement required (average plant life/7-year replacements) over the remaining lifetime at 4 hours per replacement.

Labor (PWR) = (2 hours/valve)(2 valves)(2 checks/year)
+ (27.7 years/7 years)(4 hours/valve)(2 valves)/(27.7 years)
= 8 hours/year(checks) + 1.14 hours/year (average diaphragm replacement)
= 9.14 hours/RY

Labor Cost = (9.14 hours/RY)($2,270/man-week)/(40 hours/man-week)
= $519/RY.

Thus, the operation and maintenance cost was ($519/RY)(47 plants)(27.7 years) or $675,686 and the total industry cost for the resolution of this issue was approximately $(255,000 + 675,000) or $930,000.

NRC Cost: Development of the implementation of the solution, including the formulation of guidelines and documentation requirements, and review and inspection of the final installation were estimated to cost (4 man-weeks) ($2,270/man-week) or $9,080. Implementation costs were estimated to be (0.6 man-week/plant)($2,270/man-week) or $1,362/plant; for the 47 affected plants, this cost was $64,000. Review and inspection of plant operation and maintenance activities were estimated to be (0.5 day/plant-test)(2 tests/year) or 1 day/RY; at a daily rate of [($2,270/man-week)/(5 days/man-week)], this cost was $454/RY. For 47 plants with an average remaining life of 27.7 years, the operation and maintenance cost was estimated to be (47 reactors)(27.7 years)($454/RY) or $591,000. Thus, the total NRC cost was estimated to be $(9,080 + 64,000 + 591,000) or $664,000.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $(930,000 + 656,000) or approximately $1.5M. Installation of excess-flow check valves was considered a satisfactory "fix" for the possibility of sudden accumulation of combustible or explosive mixtures of H_2 resulting from a piping system break, but it was not a solution for H_2 accidents arising from slow leaks in valves or fittings, purging errors, material degradation problems, contamination, etc. Other "fixes" are required to reduce or preclude H_2 accidents from scenarios other than pipe breaks. These other "fixes" would include the installation or upgrading of existing H_2 detection and alarm systems, completion of combustible gas system design reviews and modifications to plant design and hardware, operating procedure reviews and modifications, improved preventive maintenance programs, and major modifications to the auxiliary building

ventilation system. For an assumed population of 47 plants, the total industry cost of these other "fixes" would be very much more than the costs estimated for the very restrictive "fix" (excess-flow check valves) estimated by PNL. Therefore, the cost of the other "fixes" was assumed to be an order of magnitude greater than that calculated for the installation of excess-flow check valves. Thus, the total estimate for complete resolution of the issue was at least $15M.

Value/Impact Assessment

Based on a potential public risk reduction of 11,500 man-rem a cost of $15M for a possible solution, the priority score was given by:

$$S = \frac{11{,}500 \text{ man-rem}}{\$15M}$$

$$= 767 \text{ man-rem/\$M}$$

Other Considerations

Based on the potential reduction in core-melt frequency of 5.2×10^{-6}/RY for PWRs, the cost savings from accident avoidance was ($1.65 billion)($5.2 \times 10^{-6}$/RY) (47 reactors)(27.7 years) or approximately $11.4M.[64]

CONCLUSION

For the potential reduction in both public risk and core-melt frequency, a medium priority was appropriate, regardless of potential cost, unless the value/impact score was greater than 3,000 man-rem/$M, in which case, a high priority would be appropriate. For the value/impact score to be $3,000 man-rem/$M, the total industry resolution cost could not exceed about $3.8M. Based on the relatively detailed estimate of the cost of excess-flow check valve installation (~$1.6M), which was only a small portion of the total "fix," and extrapolation, it appeared very unlikely that this issue could be completely resolved for less than $4M. Therefore, the issue was given a medium priority (See Appendix C).

The staff's technical findings and regulatory analysis were reported in NUREG/CR-5759[1544] and NUREG-1364,[1545] respectively. The issue was RESOLVED with no new requirements[1546] and Generic Letter 93-06[1547] was issued to inform OLs and CPs. However, RES recommended that the SRP[11] be revised to: (1) include the information contained in Generic Letter 93-06[1547]; and (2) reference EPRI NP-5283-SR-A,[1548] "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations - 1987 Revision"; the latter recommendation was consistent with the RES recommendation made with the resolution of Issue 136. Consideration of a 20-year license renewal period would not affect the resolution of Issue 106.

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1547. Letter to All Holders of Operating Licenses or Construction Permits for Nuclear Power Reactors, "Research Results on Generic Safety Issue 106, 'Piping and the Use of Highly Combustible Gases in Vital Areas' (Generic Letter 93-06)," U.S. Nuclear Regulatory Commission, October 25, 1993.

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ISSUE 110: EQUIPMENT PROTECTIVE DEVICES ON ENGINEERED SAFETY FEATURES

DESCRIPTION

Historical Background

This issue was identified in a DST/NRR memorandum[1335] which addressed a condition in which some protective devices intended to trip active engineered safety features (ESF) components, under indication of equipment problems, are overridden by ESF actuation (ESFA) signals. This issue addressed two main concerns: (a) ESF protective trip bypass; and (b) ESF reset capabilities after being tripped.

ESF Protective Trip Bypass: Most ESF equipment are provided with protective devices designed to trip such equipment when an indication of a fault is detected. Following an emergency ESFA, only a few essential protective devices are retained in an active mode. The remaining, non-essential, protective devices are automatically bypassed. The bypassed non-essential protective devices do not cause an ESF trip but, on detection of a fault condition, will alarm in the control room. The intent of this design aspect is to ensure continued operation of an ESF during a genuine demand, without spurious or unnecessary trips from protective devices.

This issue addressed the concern that, during an ESFA, a component could self-destruct if a real fault existed with the protective trip bypassed, thus causing the ESF to become unavailable for event mitigation. The current philosophy of bypassing these ESF trips does not take advantage of the adequate time that may be available to correct the cause of the trip and restart the ESF in time to perform its safety function.

The question being raised by this issue is: Is it better for safety to allow all ESF protective trips to be active (i.e., no trip bypass) during emergency conditions and depend on the operator for restoration? The advantage of all-trips-active condition is more assurance of ESF integrity which, in turn, ensures reactor safety. The disadvantages include: (a) increased ESF trips from conditions that do not truly threaten operability; and (b) an increase in the number of spurious ESF trips which may complicate operators' actions to recover from accident conditions, without adding much protection to the ESF equipment.

ESF Reset Capabilities: A related concern addressed the reset capabilities of protective devices. Protective devices for some ESFs must be reset after a trip and before the ESF can be restarted. Most reset capabilities are designed primarily for normal plant operation and test and maintenance activities. In some instances, an ESF reset capability (which must be exercised if the equipment trips) may be at a location that is inaccessible or hazardous during accident conditions. The issue considered was whether the ESF reset capabilities were appropriately located.

Safety Significance

Bypassing ESF equipment protective trips during emergency conditions may cause some of this ESF equipment to self-destruct, if a genuine ESF trip condition

existed and the operators failed to take the appropriate corrective actions. This may complicate the event and lead to higher risk.

Similarly, an ESF reset capability that is inaccessible during emergency conditions will render the ESF inoperable, if the latter is tripped and cannot be reset and restarted. This may complicate the event and lead to higher risk.

Possible Solution

A possible solution for the ESF protective trip bypass concern was to enable all ESF protective trips during emergencies as well as during regular surveillance and normal operation. A possible solution for the ESF reset capability concern was to require licensees to survey and relocate, as necessary, any ESF reset capabilities that may be needed during emergencies but found to be inaccessible.

PRIORITY DETERMINATION

ESF Protective Trip Bypass: The ESFs that are the subject of this issue are the Emergency Diesel Generators (EDG), safety-related pumps and pump motors, and safety-related valve motor operators. The following is a discussion of: (1) essential and non-essential protective trips; (2) trip alarms; (3) operating philosophy pertinent to ESF protective trips; and (4) operational statistics.

(1) Essential and Non-essential Protective Trips: The function of an essential trip is to prevent true threats to the integrity and the operability of the ESF components. On the other hand most of the non-essential trips are intended to restrict ESF operation to a narrow, optimum operation band. In the current ESF design philosophy, less than optimum operating conditions are acceptable in cases of emergency. Draft Regulatory Guide 1.9, Rev.3, which was the proposed resolution for Issue B-56, "Diesel Reliability," contains the staff position on protective trips for EDGs. Also, Regulatory Guide 1.106,[1215] provides guidance to the industry that because MOVs are operated intermittently their thermal overload protection may be bypassed in cases of emergency.

The EDGs are equipped with various protective trips, but typically only a few essential trips remain active for EDG protection when an ESF signal is present. Essential EDG trips include: (1) Low Lube Oil Pressure, which protects against the seizure of the EDG's internals; (2) Generator Overspeed, which protects against the destruction of the generator in case of loss of load; and (3) Generator Differential Overcurrent, which protects against major damage in the internal generator windings. Other, non-essential trips, (e.g., high jacket water temperature) are bypassed during emergency operation.

Similarly, safety-related pump and valve motors are protected during emergency operation by a few essential trips, for example: (1) Ground Fault and Overload Protection, which protects against losing the electric bus or the pump motor; (2) Pump Overspeed, which protects against pump damage; and (3) Torque and Limit Switches for Valves, which protect against damage of the valve internals. Non-essential trips (e.g., thermal overload protection for MOVs) may be bypassed. As many as nine non-essential trips are bypassed on an EDG in case of an emergency actuation. Similarly, a few trips are bypassed on other ESF equipment.

(2) Trip Alarms: For a bypassed non-essential protective device the automatic trip action is blocked but a trip alarm is activated in the control room if a trip condition is reached. Also, as a condition for bypassing non-essential trips, licensing guidance requires that there must be sufficient time for an operator to react to the trip alarm and take the appropriate corrective actions (see Regulatory Guide 1.9).

(3) Operating Philosophy: Current operator training and EOPs require an operator, in cases of emergency, to first take some immediate actions that are committed to memory, then take some follow-up actions. The immediate actions include ensuring that all the needed ESFs have properly started and continue to operate. The follow-up actions include:

(a) taking the necessary remedial actions if a trip or a trip alarm (either essential or non-essential) is activated. The remedial actions depend on the type of accident and the stage at which the trip or the trip alarm occurs (e.g., reactor conditions changing rapidly, or core cooling has stabilized, preferred power supplies are restored, etc.);

(b) determination of whether any of the operating ESF equipment is only needed in a standby capacity, or not needed and may be turned off. This is done to conserve energy and cooling water which may be necessary for long-term recovery following an accident.

Considering the above operating philosophy and operator actions, activating the non-essential trips during emergencies does not provide much additional protection to the ESF equipment.

(4) Operational Statistics: Operational statistics compiled by AEOD and industry (EPRI NP-5924, July 1988) indicate that a large percentage of ESF trips are spurious and unnecessary. This means that activating additional trips during emergency conditions is likely to increase the number of spurious trips. Therefore, if the non-essential trips are retained (not bypassed), the actuation of these additional trips (valid or spurious) is likely to divert the operators' attention from the important task of controlling the accident while not adding much protection as outlined above.

ESF Reset Capabilities: The licensing guidance for ESF equipment [10CFR50.55a(h), "Protection Systems," (which endorses IEEE-279) and Regulatory Guide 1.153 (which endorses IEEE-603)] requires that safety system reset capabilities by an operator must be readily achievable. Typically, for systems required during emergency conditions, the reset capability is located in the control room.

Most reset capabilities are designed for equipment testing, maintenance, and normal plant operation. These reset capabilities are not affected by this issue. However, some ESF equipment must be reset prior to restart. These reset capabilities are either accessible during emergencies (as discussed earlier) or are designed to automatically reset and restart after trip when there is an emergency signal present. For instance, a high pressure injection pump, after tripping on undervoltage, will automatically reset and restart when the diesel generator is loaded.

Frequency Estimate

A quantitative evaluation of the effect on risk of the possible solution was conducted by constructing event trees.[1383] The solution called for enabling all protective ESF trips during emergency conditions as well as during normal test and surveillance operation. This solution would increase reliance on the operator to diagnose the reason for ESF trips and quickly restore the tripped equipment.

Best estimates (mean value) of the conditional probability of core damage given an ESF actuation were calculated for the base case and two additional cases, Case 1 and Case 2. Below is a discussion of the assumptions made for the analyses:

(1) The event tree analyses considered a simplified composite plant with an ESF that has: (1) two trains of safety injection pumps; (2) two EDGs; and (3) an Emergency Feedwater System (EFWS) that has two electric- and one turbine-driven pumps. Although BWRs do not have EFWS, they have electric- and turbine-driven pumps. This makes the simplified composite plant equally representative of BWRs and PWRs for the purpose of this evaluation. The event tree analyses provided an estimate of the conditional probabilities of core damage for the composite plant given an ESF actuation.

(2) It was assumed that 80% of the ESF trips occur in the first few minutes of ESF actuation. Of all ESF trips, the non-essential trips were assumed to be of a less serious nature than the essential trips and, therefore, were assumed to be recoverable within a few minutes. The number of trips that require moderate to long periods of time for recovery was assumed to remain unchanged despite the additional trips. Therefore, the percentage of the ESF trips recoverable in a few minutes was increased, while the percentage of those requiring longer recovery times was decreased.

In reality, some non-essential trips may require long recovery times. The effect of neglecting this possible increase in trips requiring long recovery times was a decrease in the CDF estimate. For Case 1, the percentage of trips that are recoverable in a few minutes was increased from 80% for the base case to 90%. The percentage of trips that fall in the moderate and long recovery times were decreased from 15% and 5%, to 7.5% and 2.5% respectively. For Case 2, the percentages were 96%, 3%, and 1%, respectively.

(3) The probability of operator failure to recover the tripped ESF was assumed to remain the same as the number of spurious and non-essential trips increased. However, the anticipated increase in trips is likely to heighten the stress level of operators and consequently increase the probability of their failure to recover the tripped ESF equipment.

(4) The base case modeled the existing number of essential ESF trips. Case 1 assumed that, if all ESF trips are enabled, the rate of ESF failure to continue to run will be doubled. Case 2 assumed that the rate of ESF failure to continue to run was increased by a factor of 5. The increase in the failure rate by factors of 2 and 5 was not intended to be proportional to the effect of the additional trips, but intended to show the trend of plant risk as a result of increasing the number of non-essential trips. The actual increase in risk due to activating non-essential trips during

emergencies was believed to be much smaller. The results of the analysis are shown below.

Mean Conditional CDF, Given An ESFA	
Base Case	1.4×10^{-4}/RY
Case 1	1.9×10^{-4}/RY
Case 2	3.4×10^{-4}/RY

As indicated above, the event tree analyses showed an increase in risk if the suggested solution were adopted. The conditional CDF estimate for the base case was 1.4×10^{-4}/ESFA, while the conditional CDF for Cases 1 and 2 were estimated at 1.9×10^{-4}/ESFA and 3.4×10^{-4}/ESFA, respectively. Although the difference between the base case CDF and the two CDF estimates for Cases 1 and 2 was not substantial, it indicated a trend toward increasing risk.

Other Considerations

Although not explicitly included in the analysis, the additional trips may provide some protection against long-term system faults. Therefore, by causing some early trips with short recovery times, the additional trips may avoid later system faults requiring longer recovery times. This effect tends to limit the increase in overall CDF (i.e., trade some early ESF trips for later system faults).

The following comparison delineates the competing risks resulting from not bypassing non-essential trips. In the base case as well as the solution cases, the essential trips and all trip alarms are active and will actuate if their setpoints are reached. The only difference between the base case and solution cases is that, in the latter cases, non-essential trips will actuate automatically. Therefore, in a solution case, the only possible non-essential trips are: (i) spurious non-essential trips that interrupt ESF function and distract operators, clearly increasing the likelihood of core damage; (ii) valid non-essential trips that help long-term system operation by permitting early equipment repair to avoid later system faults, thus reducing the overall probability of ESF failure to continue to operate and therefore decreasing the likelihood of core damage; or (iii) valid non-essential trips that do not help long-term system operation and act like (i) above (spurious trips).

Data show that spurious trips are more frequent than valid trips. Therefore, even if every valid non-essential trip is assumed to help long-term system operation, there would be a net increase in CDF if it is assumed that trips of categories (i), (ii), and (iii) are of equal importance. However, the importance of any trip depends on the accident scenario, timing of the trip, available equipment, and operator actions. It is likely that an ESF trip causing an ESF interruption of a short duration in the early stages of an accident (when the reactor core conditions are still rapidly changing) is more serious than a later interruption of an ESF equipment of a longer duration (when the accident may have been stabilized or terminated, other equipment became available, more support staff is brought on site for added help, or when requirements for decay heat removal may have diminished).

CONCLUSION

As shown above, enabling the non-essential ESF trips (i.e., not bypassing them) during emergency conditions causes an increase in ESF spurious trips and is predicted to increase plant risk. By interrupting the ESF functions unnecessarily, these spurious trips divert the operators' attention from the more important tasks of controlling an evolving accident. This increases the likelihood of core damage. Therefore, it was concluded that changes to the current ESF protective trip philosophy would not improve safety. Thus, this issue was DROPPED from further pursuit. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1335. Memorandum for W. Minners from F. Rowsome, "A Candidate Generic Safety Issue," December 11, 1984.

1383. Memorandum for R. Baer from S. Diab, "Supporting Analyses for Prioritization of Issue 110, 'Equipment Protective Devices on Engineered Safety Features,'" April 16, 1992.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 113: DYNAMIC QUALIFICATION TESTING OF LARGE BORE HYDRAULIC SNUBBERS

DESCRIPTION

Historical Background

This issue was raised[1014] in March 1985 to address the staff's concern that there were no requirements for dynamic qualification testing or dynamic surveillance testing of large bore hydraulic snubbers (> 50 kips load rating). The safety concern was the integrity of the steam generator lower support structures (SGLS) when subjected to a seismic event.[1015] However, the issue was applicable to all LWRs with components, structures, and supports that rely on LBHS for seismic restraint and other dynamic loads such as high energy line breaks and water hammers.

Safety Significance

In the absence of the restraint to the steam generators provided by the LBHS, the steam generator support structures (SGS) might fail. Failure of the SGS might subsequently result in rupture of the primary system piping (large-break LOCA), the main steam lines (MSLB), and the feedwater (normal and auxiliary) piping lines. Such failures could result in a core-melt from the loss of all means of core cooling and could pose a significant risk to the public. Other dynamic load events could further increase the safety significance of this issue but, this limited analysis focused primarily on the seismic concern raised.

Possible Solution

The staff suggested[1014] a number of tests or alternative tests to provide adequate assurance of the operability of the LBHS when subjected to a seismic event. The test options primarily focused on dynamic cyclic testing, to assure operability of the snubber control valves when subject to cyclic loads, and the determination (or correlation) of the snubber system spring rate when subject to cyclic loads. As previously stated, the resolution may effect all operating plants (BWRs and PWRs) that use LBHS as seismic restraint devices.

PRIORITY DETERMINATION

Frequency Estimate

Initiating Frequency: As stated above, the initiating event evaluated in this analysis focused on the potential seismic-induced movement of steam generators in PWRs. The probability of failure of the SGS is 0.05[1016] for a peak ground acceleration of 0.5g, which is approximately three times that of an SSE. The SGS failure probability corresponds to the failure probability of 0.05 for hydraulic snubbers from all design causes.[1017] Thus, given a failure of the LBHS in the SGS, the SGS under a 3 SSE loading was assumed to have a failure probability of 1. Assuming the failure probability is proportional to the load, the failure probability of SGS and LBHS subject to a SSE loading is therefore 0.017.

The function of a LBHS during an earthquake is to lock-up and to resist motion of the steam generator. Failure to lock-up in either the compression or tension stroke will result in loss of snubber restraint (soft snubber strain rate under repetitive input loading). For this analysis, the inertial time lag (rocking) of the steam generator during its inertia-induced motion in one direction (snubber compression mode on one side and tension on the other side of the steam generator) combined with failure of the snubber to lock-up and resist the inertia-induced movement of the steam generator was considered. Thus, only one-half of the seismic input frequency was involved in the relative motion (rocking) between the steam generator and the snubber rigid attached wall.

Failure of the snubber from sticking of the control valve accounts for approximately 1% of the tested snubber failures.[1017] Assuming that the control valves are as likely to stick open (failure to lock-up) as to stick closed (failure to unlock), the LBHS failure to lock-up is $(0.017)(0.01)(0.5) = 8.5 \times 10^{-5}$/demand.

The strong ground motion of the SSE was assumed to contain an input frequency of 33 cycles/second over a duration of 10 seconds. Considering only one-half the input frequency as discussed above, the snubbers could experience $(0.5)(33)(10) = 165$ demands. The probability of the LBHS and SGS failure, given an SSE, would therefore be $(8 \times 10^{-5})(165) = 0.014$. A possible conservatism in this assumption is that all the LBHS in the SGS ganged (grouped LBHS arrangements) sets of snubbers are assumed to fail as one composite LBHS failure. Such a common mode failure was assumed to be representative of a generic design defect that results from the absence of adequate dynamic testing programs.

Core-Melt Frequency: Given an SSE event with a return period of 2×10^{-4}/RY (References 1018 and 1019), and the conditional failure probability of a SGS/SSE as (1.4×10^{-2}), the core-melt frequency was estimated to be $(2 \times 10^{-4}/\text{RY})(1.4 \times 10^{-2}) = 2.8 \times 10^{-6}$/RY.

Containment Failure Frequency: For this analysis, the containment failure probability was assumed to be 1 due to overpressurization from the high energy released into the containment from the piping failures or containment bypass by way of the ruptured steam lines.

Consequence Estimate

Based on the above frequency estimates, the probability of a large release from a core-melt caused by dynamic (cyclic) failure of the LBHS during a SSE is $(2 \times 10^{-4}/\text{RY})(1.4 \times 10^{-2})(1) = 2.8 \times 10^{-6}$/RY. The public dose within a 50-mile radius of the plant, with a surrounding uniform population density of 340 persons per square mile, no evacuation, and meteorology typical of the Braidwood site is $(2.8 \times 10^{-6}/\text{RY})(5.1 \times 10^{6}$ man-rem) = 14.3 man-rem/RY. Assuming an average remaining plant life of 30 years, the potential public risk was approximately 430 man-rem/reactor.

Cost Estimate

The cost of the proposed solution(s) will be highly dependent on the option selected to verify the dynamic capability of the LBHS in operating plants, i.e., a snubber vendor qualification of snubber types and/or in-plant tests that augment the current TS functional test requirements. For operating plants, the

cost will be highly dependent on the state-of-art of test equipment, the number of snubbers tested per plant, the surveillance frequency of the tests, the existence of or lack of prior qualification tests (snubber vendor-specific), the vintage and distribution of various vintage LBHS in the plants, and replacement power costs (should the LBHS tests result in extended plant outage time).

The expected large variations in all the above elements necessary to arrive at a realistic cost estimate for this issue clearly indicated that the costs used in this analysis must be regarded as very rough estimates.

Vendor Qualification Tests: The average cost for snubber qualification tests (including dynamic testing) was estimated to be $100,000 per snubber type.[1017] This cost may be significantly higher per snubber type for the smaller population LBHS, but insignificant on an average per-plant basis when compared to other industry costs. Further functional (in-plant) tests of the LBHS that might augment the existing TS requirements, given an adequate vendor qualification testing program (including dynamic testing), may be lower than the in-plant tests cost estimated in this analysis.

In-Plant Testing: The annual testing cost for hydraulic snubbers was estimated to be approximately $1000/snubber. Assuming the snubber population ranged from 500 to 1000 snubbers/plant, and 15% of the snubbers were LBHS,[1017] each plant may have approximately 75 to 150 LBHS.[1020] Based on the existing TS functional testing criteria,[1020] it was assumed that 20% to 25% of the LBHS will be tested per refueling outage (approximately every 1.5 years). This amounted to 11 to 23 LBHS on an annual basis.

The existing test requirements for LBHS were estimated to cost approximately ($1000)(0.15)(75 to 150) or $11,000 to $23,000 per RY or, on an average, approximately $17,000/RY. Estimating that a dynamic testing requirement (including setup, tests, and equipment leasing) would increase the existing LBHS test cost by 50% to 100% yielded an increased cost of approximately $8,500/RY to $17,000/RY. The present worth costs, at a 5% discount rate over 30 years, ranged from $131,000 to $262,000 per plant. These costs would be attributed to an in-plant dynamic testing requirement for LBHS only.

Replacement Power: Cost factors related to a hydraulic snubber test program according to the TS were cited in NUREG/CR-4279.[1017] The TS snubbers testing phase resulted in extending the plant outage time by approximately 3 days. Assuming the existing TS functional test surveillance requirements are linear with respect to the LBHS population (15%), the outage extensions due to the current LBHS testing may be extended an additional 0.45 day. If it is assumed that the outage is extended only one additional hour per LBHS tested (11 to 23 LBHS), the outage extension ranges from one-half day to one day per year, which is consistent with the above estimate. Therefore, the estimated replacement power cost of $500,000/day yields an annual replacement power cost of $250,000 to $500,000/plant-year. Based on a 5% real discount rate, the present worth replacement power cost over 30 years may be $3.85M to $7.7M per plant.

NRC Cost: The estimated NRC cost for this issue ranged from $50,000 to $100,000, including technical assistance contractor costs. The effort would likely involve a review of the LBHS used in industry, determination of the need (risk reduction) for additional LBHS test requirements, discussions with snubber vendors,

development of acceptable testing requirements, and possible preparation of additional TS requirements.

Total Cost: The NRC cost ($50,000 to $100,000) would be insignificant when compared to the industry costs. A per plant cost for vendor qualification of each snubber type would likely be distributed over the total population of the tested snubber type and not significantly affect total industry costs. In addition, some LBHS types may have existing and adequate testing programs. The present worth of surveillance testing costs ($131,000 to $262,000) and replacement power cost ($3.85M to $7.7M) yielded a cost that ranged from approximately $4M to $8M per plant. Therefore, the average cost to implement a dynamic testing requirement in operating plants for the LBHS was estimated at approximately $6M/plant, if plant outage time is extended because of the additional tests. If the LBHS test can be done within normal plant outages (refuelings), the total cost would be approximately $200,000/plant.

Value/Impact Assessment

Based on a public risk reduction of 430 man-rem/reactor and an estimated average cost of $6M/reactor (including replacement power costs), the value/impact score was given by:

$$S = \frac{430 \text{ man-rem/reactor}}{\$6M/\text{reactor}}$$

$$= 72 \text{ man-rem/\$M}$$

If replacement power costs are not involved, the value/impact score would be:

$$S = \frac{430 \text{ man-rem/reactor}}{\$0.2M/\text{reactor}}$$

$$= 2150 \text{ man-rem/\$M}$$

Other Considerations

(1) The uncertainties in this analysis were large for the risk estimates. The risk for this issue was estimated to result from the absence of a LBHS dynamic qualification test requirement, or a LBHS dynamic functional surveillance test program in the TS. The risk estimates center on failure of the SGS due to a common mode failure of the LBHS in the event of a SSE seismic excitation. In estimating the probability of failure of the LBHS, it was assumed that the LBHS control valves may fail open during seismic excitation, e.g., due to cyclic (frequency) loading, and thereby result in free motion (lack of snubber restraint) and lateral movement of the steam generators. Lateral movement of the steam generators (absent LBHS restraint) was assumed to fail all the SGS and result in massive piping failures in the primary and secondary piping runs.

(2) The existing TS functional test requirements provided some unknown amount of assurance relative to cyclic operability to the LBHS, but the strain rate (k) during repetitive loadings was not assured and therefore may be even more uncertain. The analysis did not treat the above uncertainties in the estimates because of the lack of supportive data. Previous

qualification testing (if dynamic tests were performed) might negate the need for further strain rate (dynamic) testing since it could be inferred that the operability and repetitive loading capacity for a given design was confirmed by the qualification tests and only operability need be verified in subsequent tests.[1021]

In the absence of any correlation between the LBHS operability and strain rate capacity when subject to dynamic loading, the assumption that control valves may stick open during the cyclic loading, and remain open, assumed a generic design defect might exist. This inherent assumption in the analysis may overestimate the probability of LBHS failure by one to two orders of magnitude. Thus, the risk estimates may be high for the analyzed SGS structure failure scenario.

(3) The LBHS are also used to support other components in nuclear power plants. The consequences (plant damage states) from other dynamic loads or other accident scenarios that might be similar to the seismic-induced LBHS failures are assumed to be dominated by the seismic-induced SGS structure failure scenario. A more detailed analysis that examines all the potential plant damage states that may result from LBHS failures could be considered in the final resolution.

(4) The resolution and implementation of the NRC Piping Review Committee recommendations (see Issue 119) may result in removal of some of the piping snubbers. Thus, more flexible piping systems may result in higher nozzle loads to the steam generators and other support structures during seismic events.[1018] In such cases, the reliability of the remaining smaller population of snubbers (including LBHS) may become more critical. As a further example, the GDC-4 limited scope rule would allow removal of many snubbers (including LBHS) from PWR reactor coolant system piping and large components, such as steam generators, subject to NRC approval of demonstrated acceptability of the licensees' requests. Additionally, the proposed GDC-4 broad scope rule change, if approved, will expand the scope of the limited scope rule to all high energy piping systems in all nuclear power plants. Thus, the determination of the need for dynamic qualification testing of the LBHS should also consider the potential impacts of Issue 119, and specifically the GDC-4 rule changes.

(5) Some of the uncertainties in the cost estimates were due to the variations in snubber vendors' qualification programs, from plant to plant design differences, whether or not plant refueling outage times would be extended due to the additional testing, and other elements discussed above. Therefore, a wide uncertainty band for costs existed and no precise generic cost estimate seemed appropriate for this issue, i.e., the costs may vary significantly from plant to plant. As previously stated, the cost estimates should be regarded as very rough estimates. The value/impact ratio of this issue will be strongly influenced by any outage extension that may or may not result from additional LBHS testing.

CONCLUSION

The purpose of this issue was to assess the need for an NRC requirement for dynamic qualification testing of LBHS in operating plants. The limited assessments provided in this analysis should only be considered as rough baseline

risk, cost, and value/impact estimates. Further and more detailed analyses may show either higher or lower values. However, this analysis identified that a broader and more complete evaluation was needed to resolve the issue. Based on the estimates determined in this analysis, the potential need for higher reliability LBHS (pipe snubber removal and optimization programs were being pursued), and the observed failures of LBHS in operating plants,[1015] this issue was given a high priority ranking (See Appendix C). Work being done by RES in the Nuclear Plant Aging Research,[1022] the resolution of Issue 119, and the effects of the GDC-4 rule changes were to be considered in the resolution of this issue.

In resolving the issue, the staff concluded that there were few cost-beneficial changes to existing requirements that would result in improved LBHS reliability and reduced risk. However, it was recommended that a Regulatory Guide be developed for future plants. Thus, this issue was RESOLVED and no new requirements were established.[1450] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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1014. Memorandum for F. Schroeder from D. Crutchfield, "Dynamic Qualification Testing of Large Bore Hydraulic Snubbers," March 6, 1985.

1015. Memorandum for R. DeYoung, et al., from C. Heltemes, "Failure of Large Hydraulic Snubbers to Lock-up," September 21, 1984.

1016. NUREG/CR-4334, "An Approach to the Quantification of Seismic Margins in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, August 1985.

1017. NUREG/CR-4279, "Aging and Service Wear of Hydraulic and Mechanical Snubbers Used on Safety-Related Piping and Components of Nuclear Power Plants," U.S. Nuclear Regulatory Commission, February 1986.

1018. NUREG/CR-4263, "Reliability Analysis of Stiff Versus Flexible Piping Final Project Report," U.S. Nuclear Regulatory Commission, May 1985.

1019. NUREG/CR-3756, "Seismic Hazard Characterization of the Eastern United States," U.S. Nuclear Regulatory Commission, April 1984.

1020. NRC Letter to All Power Reactor Licensees (Except SEP Licensees) and All Applicants for Licensees to Operate Power Reactors, "Technical Specification for Snubbers (Generic Letter 84-13)," May 3, 1984.

1021. EPRI NP-2297, "Snubber Reliability Improvement Study," Electric Power Research Institute, March 1982.

1022. NUREG-1144, "Nuclear Plant Aging Research (NPAR) Program Plan," U.S. Nuclear Regulatory Commission, July 1985.

1450. Memorandum for J. Taylor from E. Beckjord, "Resolution of Generic Issue 113, 'Dynamic Qualification and Testing of Large Bore Hydraulic Snubbers,'" August 27, 1992.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 118: TENDON ANCHOR HEAD FAILURE

DESCRIPTION

Historical Background

On January 27, 1985, a dented and leaking tendon grease cap was found during inspections at Farley Unit 2 prior to the integrated leak rate test of the prestressed concrete containment structure. Subsequent detailed inspection revealed that three lower vertical tendon anchor heads were broken. Several anchor heads were then removed from the vertical tendons and magnetic particle testing revealed cracks in the ligaments between the holes in the back of the anchor heads. Metallurgical analysis of the anchor head material indicated that the failures had been caused by hydrogen stress-cracking (HSC). There was evidence of corrosion caused by hydrogen generation from the anodic reaction of zinc and steel in the presence of water since quantities of water ranging from a few ounces to about 1.5 gallons were found in the grease caps; most of the water was found in the vertical tendon lower anchor grease caps. Concerns for the generic implications of the tendon anchor failure at Farley Unit 2 resulted in the identification of this issue by DL/NRR.[1352]

A Task Force was assembled by the NRC to evaluate the anchor failures, including their failure mechanism and the safety significance on Farley and other plants with tendons supplied by the same vendor (INRYCO). The Task Force was to propose corrective action, determine the need for long-term generic action, prepare generic correspondence, and study the potential changes in Regulatory Guide 1.35.[481] At the time the anchor head cracks were found, Regulatory Guide 1.35 was undergoing revision and the supplemental Regulatory Guide 1.35.1[1360] was being developed. Work on these guides was suspended until review of the Farley tendon anchor head failure was completed.

By August 1985, the Farley anchor head failure was also studied by: (1) Inland Steel Laboratory/INRYCO, manufacturer of the Farley post-tension system; (2) Battelle Columbus Laboratories, consultant to INRYCO; and (3) BNL. In November 1985, the Task Force completed its review of the studies by these three laboratories and concluded that cracking of the anchor heads occurred in areas of high stress, was hydrogen-induced, and initiated because of the presence of water, zinc, and sulfur.

Although the Farley Unit 2 problem was concluded to be plant-specific because of the moisture-traveling path to the anchor heads, further study of the contributing factors continued. These factors, in conjunction with the incidence of HSC of anchor heads at Bellefonte and of stress corrosion cracking of anchor bolt material at Midland, prompted the staff to investigate the potential generic implications and an action plan was developed for resolution of the issue.[1358,1359] This resolution also addressed the concerns of Issue 156.2.3, "Containment Design and Inspection."

Safety Significance

The failed tendon anchor heads were found to be losing the capability of carrying tendon design force. Tests on cracked anchor heads showed them to be capable of taking the original design force. However, the mechanism of crack initiation and propagation is time-dependent and eventually these anchor heads would not be able to carry the loads. Their failure could jeopardize the containment structural integrity.

Possible Solution

A tendon inspection, repair, and surveillance program was initiated for both Farley Units 1 and 2. The licensee evaluated the containments and concluded that the structural integrity had been maintained continuously for both units. Issuance of Regulatory Guides 1.35[481] and 1.35.1[1360] would provide guidance for future plants.

PRIORITY DETERMINATION

A regulatory analysis[1353] of the proposed revision 3 to Regulatory Guide 1.35 showed that, although the changes in the guide were determined to produce an unquantifiable change in risk, they would lower the possible risk and enhance containment availability. Additional costs might be incurred by the industry (e.g., visual inspection of bottom grease caps of vertical tendons, and requirements for lift-off tests on the second containment where two identical containments exist at a site), but the relaxed requirements in other areas (i.e., tendon sample size and tendon detensioning) could produce a net cost savings, estimated to be small. It was concluded that backfitting of the revised guide would be very difficult for plants licensed before 1974 and would have to be done on a case-by-case basis, e.g., certain plants do not permit random selection of tendons for detensioning to remove a wire sample for material tests (See Section 6.2, NUREG/CR-4712).[1353] However, the staff believed that backfitting most plants licensed after 1974 was possible. Regulatory Guide 1.35.1[1360] provided essentially new guidance on predicting and evaluating prestressing forces.

Ten licensee/applicants committed to various provisions of Regulatory Guide 1.35, Rev. 3 (NUREG/CR-4712, Table 4).[1353] Therefore, the staff's recommendation was to apply the provisions of Rev. 3 to Regulatory Guide 1.35 to new licensing applicants only and allow other licensees to use it on a voluntary basis.[1361]

The proposed Regulatory Guides 1.35, Rev. 3, and 1.35.1[1360] were reviewed by CRGR in December 1989. CRGR concluded that there did not appear to be any substantial safety improvement in backfitting nor did the matter appear to qualify as a compliance or an adequate protection backfit. CRGR recommended in Meeting No. 175 that the proposed guides be issued for forward-fit only. The guides were issued in July 1990 and only affected future plants and those operating plants that voluntarily committed to the provisions of the guides.

CONCLUSION

A number of licensees voluntarily adopted the provisions of Regulatory Guides 1.35,[481] Rev. 3, and 1.35.1[1360]; some SEP plants also developed ISI programs. These actions by some operating plants and the application of these guides to future plants addressed the concerns raised by the Farley Unit 2 tendon anchor head

failure. The CRGR decision on the issuance of Regulatory Guides 1.35, Rev. 3, and 1.35.1 indicated that there was no need to backfit operating plants. Thus, this issue was RESOLVED and new requirements were issued. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

REFERENCES

481. Regulatory Guide 1.35, "Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containment Stuctures," U.S. Nuclear Regulatory Commission, February 1973, (Rev. 1) June 1974, (Rev. 2) January 1976, (Rev. 3) July 1990.

1352. Memorandum for J. Knight, et al., from H. Thompson, "Action Plan for Resolving Failure of Tendon Anchorage at Farley 2 and for Determining Need for Immediate Licensing Action on Other Facilities," June 25, 1985.

1353. NUREG/CR-4712, "Regulatory Analysis of Regulatory Guide 1.35 (Revision 3, Draft 2) -- In-Service Inspection of Ungrouted Tendons in Prestressed Concrete Containments," U.S. Nuclear Regulatory Commission, February 1987.

1358. Memorandum for H. Thompson from G. Arlotto, "RES Input - Action Plan for Resolving Failure of Tendon Anchorage at Farley-2 and for Determining Need for Immediate Licensing Action on Other Facilities," July 31, 1985.

1359. Memorandum for T. Speis and E. Jordan from J Knight, "Tendon Anchor Head Failure - Needed Licensing Action at Other Facilities," December 6, 1985.

1360. Regulatory Guide 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments," U.S. Nuclear Regulatory Commission, July 1990.

1361. Memorandum for E. Jordan from E. Beckjord, "CRGR Review of: 1. Regulatory Guide 1.35, Rev. 3, 'Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments,' 2. Regulatory Guide 1.35.1, 'Determining Prestressing Forces for Inspection of Prestressed Concrete Containments,'" July 28, 1989.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 120: ON-LINE TESTABILITY OF PROTECTION SYSTEMS

DESCRIPTION

Historical Background

This issue was raised[1271] by the staff in 1985 during the review of several plant TS when it was found that the protection system designs of some older plants did not provide as complete a degree of on-line protection system surveillance testing capability as other plants undergoing staff review and evaluation at that time.

The requirements for at-power testability of components are included in GDC 21 of Appendix A to 10 CFR 50. Supplementary guidance is provided in Regulatory Guides 1.22[1591] and 1.118[1592] and IEEE Standard 338 to ensure that protection systems (including logic, actuation devices, and associated actuated equipment) will be designed to permit testing while the plant is operating without adversely affecting the plant's operation. These requirements apply to both the RPS and the ESFAS. Existing STS indicate that it is desirable to test all protection systems through their sub-group relays every 6 months.

Safety Significance

This issue centered around the risk posed by those plants with lesser degrees of on-line testing capability and the value/impact effects of requiring modifications of the protection systems to allow for a greater degree of on-line testing. On-line testing increases the ability to detect existing failures of the protection system and could therefore result in improved reliability of the system; hence, a reduction in plant risk. In some older plants, a larger portion of the protection system hardware can only be tested through the sub-group relays during outages (i.e., shutdowns) which typically have an 18-month frequency. Therefore, modification of the protection system to allow for semiannual testing through the sub-group relays could result in risk reduction at those plants.

Possible Solution

The following two options were identified as potential solutions:

(1) Recognize that there are cases where there are no practical system design modifications that will permit at-power operation of the actuated equipment without adversely affecting the safety or operability of a plant. Exceptions could be taken that include not testing the automatic initiating logic and associated actuating devices. Actions could include: (1) submittal of information by licensees to describe and justify any deviations from regulatory requirements and to describe the revision of the plant TS stating the testing required; and (2) testing of those systems that can be tested without defeating the ESFAS train or RPS.

(2) Design and implement modifications to allow compliance with the requirements for on-line testing of all systems without defeating the ESFAS train or RPS. Each channel of the reactor trip module (RTM) needs to

be provided with two key-operated bypass switches, a channel bypass switch, and a shutdown bypass switch. The 2/4 system would then operate in the 2/3 mode during the testing.

It was believed that changing the testing frequency of the protection system components to 6-month intervals, instead of the existing 18-month intervals, would increase the reliability of these components and result in an overall enhancement of plant safety.

PRIORITY DETERMINATION

Assumptions

It was assumed that modifications would be made to allow for an increase in test frequency to 6 months (from 18 months) for 20% of the relays in the RPS. Changes in the test frequency for ESFAS relays were not considered because they could not be as readily incorporated into the representative plant PRAs.

Frequency Estimate

The Oconee 3 and Grand Gulf 1 PRAs were used as the representative PWR and BWR, respectively, to estimate the change in the reliability of RPS components due to revised testing frequency (from the current 18-month testing interval to 6-month interval) and the resultant change in the core-melt frequency.[64] Thus, the changes in core-melt frequency were estimated based on reductions in failure rates for relays in the RPS that would result from licensee implementation of potential solutions. It was assumed that the values in the Oconee 3 and Grand Gulf 1 PRAs were based on the 6-month test interval for all relays in the RPS and that these plants are in full compliance with on-line testing requirements. These values were then considered to be adjusted case values for the purposes of this analysis. Therefore, the base case represents the situation in which only a fraction of the relays can be tested during refueling outages or other extended shutdowns (an 18-month test interval for these relays is assumed).

The affected parameter in the Oconee 3 PRA was considered to be K, failure of RPS due primarily to test and maintenance faults (frequency = 2.6×10^{-5}/demand). The affected parameter for Grand Gulf 1 was considered to be C, failure to render the reactor subcritical (frequency = 7.7×10^{-7}/demand). These K and C estimates were then assumed to represent the adjusted case values. To calculate the base case values for a change in test frequency from 6 to 18 months, relay unavailability data from ANO-2 for the two testing frequencies were used. In addition, it was also assumed that the testing of all 100 relays, instead of the approximately 80 relays that are currently being tested, will increase the unavailability of 1 of 4 RTMs by 25%. The ANO-2 relay unavailability data for the 6-month and 18-month testing intervals were 7.2×10^{-4}/demand and 2.2×10^{-3}/demand, respectively.[1272] By using these values in the RPS fault tree given in NUREG/CR-2800,[64] base case values of 2.96×10^{-5}/demand and 9.2×10^{-7}/demand for K and C, respectively, were calculated. Note that these were the values relating to the 18-month testing intervals. Substituting these values for the affected parameters in the Oconee 3 and Grand Gulf 1 PRAs resulted in core-melt frequency reductions of 1.2×10^{-6}/RY and 10^{-6}/RY for a PWR and BWR, respectively. The generic release categories and containment failure modes associated with this issue were as follows:[64]

Release Category	Containment Failure Mode Probability	Whole Body Dose (Man-Rem)
PWR-3	0.5	5.4×10^6
PWR-5	0.0073	1.0×10^6
PWR-7	0.5	2.3×10^3
BWR-2	1.0	7.1×10^6

Accordingly, the associated public risk reduction was estimated to be 3.3 man-rem/RY and 4.8 man-rem/RY for PWRs and BWRs, respectively.

A total of 42 operating plants were affected by this issue: 8 PWRs with an average remaining life of 27.7 years and 34 BWRs with an average remaining life of 25.2 years. For the 8 affected PWRs, the estimated risk reduction was [(8)(27.7)(3.3)] man-rem or 731 man-rem. For the 34 affected BWRs, the estimated risk reduction was [(34)(25.2)(7.1)] man-rem or 6,083 man-rem. Thus, the average risk reduction was approximately 162 man-rem/reactor.

Cost Estimate

The plants affected by this issue were divided into two groups: Group 1, consisting of plants where no design modifications that would permit testing of the RPS at full power were possible; and Group 2, consisting of plants that could possibly implement design modifications that would permit this testing. It was assumed that the affected plants were divided equally into these two groups (21 plants each) and had an average remaining life of 26.9 years.

Industry Cost: The implementation of the possible solution for Group 1 plants would require 16 man-weeks/plant broken down as follows:

Inspection/review of current plant configuration	= 1 man-week
Researching possible design modifications	= 3 man-weeks
Analyze/justify deviations from regulatory requirements	= 4 man-weeks
TS changes and associated technical/legal/administrative support	= 8 man-weeks

At approximately $2,270/man-week, the cost of implementation for Group 1 plants was estimated to be (16 man-weeks/plant)($2,270/man-week) or $36,000/plant. The implementation cost for Group 2 plants was estimated to consist of about $50,000/plant hardware costs and about 21 man-weeks/plant of labor itemized as follows:

Inspection/review of current plant configuration	= 1 man-week
Design modifications	= 3 man-weeks
Install and test design modifications	= 16 man-weeks
Revise testing procedures	= 2 man-weeks

Similarly, at $2,270/man-week, the labor cost was estimated to be (21 man-weeks/plant)($2,270/man-week) or $48,000/plant. Therefore, the total implementation cost/plant for Group 2 plants was ($48,000 + $50,000) or approximately $100,000. Thus, the average implementation cost for the 42 affected reactors was $68,000/plant.

It was assumed that Group 1 plants would require additional inspection activities during outages associated with assuring the operability of the relays in the RPS. It was estimated that an additional 4 man-hours/relay (i.e., those 20 relays that cannot be tested at power) would be required every 6 months for Group 1 plants for a total of 160 man-hours/RY. For Group 2 plants, it was estimated that an additional 2 man-hours/relay would be required every 6 months for a total of 80 man-hours/RY. Since most of the work would be in radiation zones, a 75% utilization factor for labor (210 man-hours/RY for Group 1 plants and 110 man-hours/RY for Group 2 plants) was assumed. At $2,270/man-week, maintenance and operation costs for Group 1 and Group 2 plants were estimated to be $12,000/RY and $6,200/RY, respectively. Using a 5% discount rate, the present worth of the recurring costs associated with plant maintenance and operation for Group 1 and 2 plants were $6,700/RY and $3,400/RY, respectively. Thus, the estimated operations and maintenance costs were $180,000/plant and $91,000/plant for Group 1 and Group 2 plants, respectively, and the average cost for all affected plants was $136,000/plant.

NRC Cost: NRC resource requirements consisted of preparation of a generic letter to the affected plants to inform them of the potential problems and requiring licensee inspection/review of the RPS testing capabilities, as well as the technical analyses and/or design modifications needed to implement the proposed resolutions. This effort was estimated to require 6 man-weeks of NRC labor or $14,000. For the 42 affected plants, this cost averaged $330/plant.

In addition, it was estimated that approximately 12 man-weeks (or $27,000/plant) of NRC labor were required for each Group 1 plant to review and approve licensee evaluations and TS changes. For each Group 2 plant, it was estimated that 10 man-weeks (or $23,000/plant) would be required for the review and approval of licensee evaluation, proposed design modifications, and TS changes. Thus, the average NRC cost for this effort was $25,000/plant for the 42 affected plants.

Inspection-related costs for each plant would be about $4,600/year for the remaining life of the affected plants. At a 5% discount rate, this translated to a present worth of $2,600/RY. This cost was $70,000/plant based on the average remaining life of the affected plants.

Total Cost: Based on the above estimates, the average cost for implementing the possible solutions was $[68,000 + 136,000 + 330 + 25,000 + 70,000]/plant or approximately $0.3M/plant.

Value/Impact Assessment

Based on a potential public risk reduction of 162 man-rem/reactor and an average cost of $0.3M/reactor, the value/impact score was given by:

$$S = \frac{162 \text{ man-rem/reactor}}{\$0.3M/\text{reactor}}$$

$$= 540 \text{ man-rem/\$M}$$

Other Considerations

(1) It was estimated that, for Group 1 plants, 1 man-week of utility labor in a radiation zone will be required to inspect the non-testable relays and

review the system design. Group 2 plants would be subjected to this review and would also require an additional 10 man-weeks to install the design modifications and 4 man-weeks to test the modified system. It was assumed that testing would be performed outside containment where the dose rate is 2.5 millirem/hr. It was further assumed that the work involved a 75% utilization factor. The implementation dose was, therefore, estimated to be about 1 man-rem/plant.

(2) It was estimated that, for Group 1 plants, operation and maintenance would require additional inspection activities during plant outages associated with assuring the operability of the relays in the RPS. It was estimated that a total of 160 man-hours/RY would be required for Group 1 plants. For Group 2 plants, it was estimated that the labor requirements were 110 man-hours/RY in a radiation zone. Assuming a 75% utilization factor, the total operation and maintenance dose was estimated to be about 12 man-rem/plant.

CONCLUSION

The estimated potential public risk reduction resulting from improvement in the on-line testability for the RPS at some older plants was significant and the value/impact score indicated a medium priority. Neglecting the ESFAS relays could result in an underprediction of the total potential risk reduction. Experience showed that testing of protection systems at power can have the potential for subtle interactions with other safety systems and/or plant operation that might result in negative effects on plant risk (i.e., an increase in plant risk). In addition, the negative aspects of increased testing (human error and reduced redundancy) could also produce a competing impact on plant risk. Based on these considerations and the value/impact score, this issue was given a medium priority ranking (See Appendix C) and RESOLVED with no new requirements.[1508] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

REFERENCES

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

1271. Memorandum for T. Speis from R. Bernero, "Request for Prioritization of Potential Generic Issue Per Office Letter No. 40," August 4, 1985.

1272. Memorandum for R. Mattson from F. Rosa, "Combustion Engineering Standard Technical Specifications (NUREG-0212) - Proposed Revision 3 - Relay Testing," October 8, 1982.

1508. Memorandum for J. Taylor from E. Beckjord, "Final Technical Resolution of Generic Safety Issue 120, 'On-Line Testability of Protection System,'" March 4, 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

1591. Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions," U.S. Nuclear Regulatory Commission, February 1972.

1592. Regulatory Guide 1.118, "Periodic Testing of Electric Power and Protection Systems," U.S. Nuclear Regulatory Commission, June 1976, (Rev. 1) November 1977, (Rev. 2) June 1978, (Rev. 3) April 1995.

ISSUE 121: HYDROGEN CONTROL FOR LARGE, DRY PWR CONTAINMENTS

DESCRIPTION

In December 1984, the staff recommended in SECY-83-357B[861] that rulemaking with regard to H_2 control for LWRs with large, dry containments could be safely deferred due to the greater inherent capability of these containments to accommodate large quantities of H_2. This issue was identified to document the staff's research on H_2 control in large, dry PWR containments.

NRC experimental and analytical programs were initiated to provide data to supplement the experiments that were carried out at the Nevada Test Station (NTS), the experience on H_2 burn during the TMI-2 accident, and earlier H_2 burn experiments in order to support a final recommendation on whether safe shutdown equipment is likely to survive an H_2 burn. Experiments were planned to determine the significance of factors not included in the NTS experiments (e.g., preconditioning of equipment to simulate aging, enclosing equipment in conduits or protective heat shields, and energized equipment). Experimental and analytical studies based in part on NTS-generated data were to be used to determine the local environmental stresses on equipment produced by convective and radiant heat flux to be expected in an H_2 burn.

In addition to the above, the staff intended to explore the possibility of forming local detonable concentrations in large, dry PWRs and the probable consequences regarding containment and equipment survivability. These items received attention from the standpoint of fundamental detonation phenomena; however, the research effort was extended to develop the capability for predicting conditions in realistic configurations.

CONCLUSION

After consideration of the safety concerns associated with this issue and the NRC resources that had been expended prior to 1984 in pursuit of a resolution, this issue was given a high priority ranking.

Staff studies showed that H_2 combustion was not a significant threat to the dry containments evaluated and the potential for global detonation was considered to be very unlikely for these containments; these findings were documented in NUREG-1150.[1081] Furthermore, the H_2 igniter systems for Zion and Surry were evaluated in NUREG/CR-5662[1464] and found to be not cost-effective. Therefore, there was no basis for new generic H_2 control measures. However, it was believed that plant-specific vulnerabilities may exist mainly due to the effects of local H_2 detonation. Activities for estimating the likelihood of local H_2 detonation and assessing the consequences would require plant-specific information and are included as part of the IPE program. Moreover, the staff is investigating H_2 control strategies via the accident management research program. In view of the above activities, the staff concluded that:

(1) The NUREG-1150[1081] findings of no problems on H_2 control for the two PWR plants investigated, the IPE plant-specific examinations for vulnerabilities to H_2 risk, and the long-term implementation of an accident

management program formed the basis for resolution of this issue for existing plants.

(2) No new regulatory guidance on H_2 control was required for existing PWR dry containments.

(3) For future plants, the need for H_2 control requirements will be examined as part of ongoing case-by-case review (certification reviews) and the generic efforts associated with 10 CFR 50.59 rule changes.

Thus, this issue was RESOLVED and no new requirements were established.[1451] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

REFERENCES

861. SECY-83-357B, "Status of Hydrogen Control Issue and Rulemaking Recommendations in SECY-83-357A," December 3, 1984.

1081. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Vol. 1) December 1990, (Vol. 2) December 1990, (Vol. 3) January 1991.

1451. Memorandum for J. Taylor from E. Beckjord, "Resolution of Generic Issue (GI) 121, 'Hydrogen Control for PWR Dry Containments,'" March 24, 1992.

1464. NUREG/CR-5662, "Hydrogen Combustion, Control, and Value-Impact Analysis for PWR Dry Containments," U.S. Nuclear Regulatory Commission, June 1991.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 123: DEFICIENCIES IN THE REGULATIONS GOVERNING DBA AND FAILURE CRITERION SUGGESTED BY THE DAVIS-BESSE INCIDENT OF JUNE 9, 1985

DESCRIPTION

Following the Davis-Besse event in June 1985, potential inadequacies of nuclear power plant design criteria and safety analyses were raised in a DST/NRR memorandum.[1323] These concerns were: (1) root causes of DBAs are not analyzed and may initiate or exacerbate a plant transient involving an initiating event; (2) allowable outage times (AOTs) and limiting conditions of operation (LCOs) may be inadequate since they are derived from potentially flawed DBA analyses; (3) high-probability common cause failures are not adequately addressed in licensing requirements; and (4) single human errors that may have a broader effect than active failures are not covered.

(1) Root Causes of DBAs: This concern addressed the possibility that auxiliary or support system failures may cause a plant transient or initiating event, as well as result in failure of one or more safety systems to perform their intended function. This concern was addressed, in part, in the resolution of Issues A-17, A-44, and A-45.

Issue A-17 specifically addressed: (1) events involving transients and loss of at least one redundant portion of any one of the systems required to respond to a transient; (2) initiating events and similar failures of redundant safety sytems; and (3) degradation of safety systems by non-safety systems, as well as degradation of auxiliary support systems such as SSW, CCW, and AC/DC power. The results of studies[1232] indicated that the causes and effects of systems interactions were plant-specific in nature due to the differences in plant designs. In addition, it was demonstrated that plant-specific PRAs were effective tools for identifying vulnerabilities to systems interactions. Currently, licensees are required to perform IPEs that include an evaluation of common cause (dependent) failures, of which, systems interactions are a subset.[1222] The information and insights gained from the Issue A-17 studies have been provided to licensees to assist in the identification and evaluation of system interactions and other common cause failures. Licensees are expected to propose plant-specific procedure and/or hardware modifications, where appropriate, to reduce their vulnerabilities to such events. Consequently, vulnerabilities to the root causes of DBAs are being systematically identified and corrected, as determined by licensees, on a plant-specific basis in the IPE process.

Issue A-44 addressed the likelihood and duration of losses of offsite power, the redundancy and reliability of onsite emergency AC power sources (e.g., diesel generators), and the effects on plant risk of failures of all AC power sources. Support system failures were important aspects of these analyses, particularly DC instrumentation and control power supplies, instrument air supplies, and auxiliary cooling systems such as SSW and CCW. Resolution of this concern involved improving the reliability of onsite AC power systems and strengthening each plant's capability to cope with an extended loss of AC power.

Issue A-45 addressed potential improvements in the reliability of shutdown decay heat removal systems that are required to operate after a transient or initiating

event and included support system failures and single-point vulnerabilities. It was concluded in NUREG-1289[1326] that resolution of Issue A-45 could only be achieved on a plant-specific basis; this is being implemented as part of the IPE process. Licensees were directed to identify decay heat removal vulnerabilities and to determine if cost-effective solutions to these vulnerabilities could be achieved.

In addition to this concern being addressed in part by resolution of Issues A-17, A-44, and A-45, IPEs currently underway by each licensee are expected to search for vulnerabilities stemming from support system failures. It is expected that these IPEs, when completed, will contain dependency tables (or other similar methods of displaying dependencies) that identify dependencies between initiating events and mitigating functions or systems. It is also expected that licensees will move expeditiously to correct any identified vulnerabilities that warrant correction in accordance with Generic Letter 88-20.[1222]

(2) AOTs and LCOs: This concern relates to the fact that AOTs and LCOs may be derived from the results of DBA analyses; if the DBA analyses are inadequate, then the AOTs and LCOs may also be inadequate. Since it is not uncommon for a plant to have several components out of service at the same time, the potential exists for operation of a plant in a dangerous configuration in which two or more components that appear in the same accident sequence are out of service. The concern focused on outages for diverse components that are not necessarily in the same safety system, such as simultaneous outage of valves in the high pressure injection system (HPIS) and the low-pressure injection system (LPIS).

This concern deals with AOTs for components and the possibility that a plant may be operating one active component failure away from core damage. A large fraction of the potential core damage probability and public risk reduction associated with this concern would be associated with removing vulnerabilities associated with the component outages. AOTs and LCOs were addressed in Issue 117 where the approach to evaluating the change in core damage probability was to remove the test/maintenance unavailability from basic events in each cut set that contained multiple test/maintenance outage terms. This analysis assumed a scenario which precluded the possibility that a plant could be operating at full power with vital equipment in different ESF systems down for maintenance, and effectively removed the vulnerabilities associated with AOTs and LCOs on components in different ESF systems and in redundant divisions of each ESF system. Issue 117 was not pursued separately because its safety concern was addressed as part of the staff's Technical Specification Improvement Program (TSIP). In addition, as part of the implementation of the Maintenance Rule,[1338] licensees should make an assessment of the total plant equipment that is out of service during power operation. This assessment is to ensure that the objective of preventing failures by performing maintenance is appropriately balanced against the objective of minimizing unavailability.

(3) High Probability Common Cause Failures: Issue A-17 addressed, among other things, the potential for common cause events involving systems/components that share physical connections or spatial configurations, or could cause operator errors that may result from operation disinformation or inhibition of an operator's ability to respond to a malfunction.[1233] An example that was addressed in the Issue A-17 analyses was a high-energy line break and the possibility that adverse environmental conditions resulting from such an event could induce failures in one or more safety systems designed to respond to the event. This is

an example of the spatially-coupled system interaction. Other examples include seismic events, fires, and floods that could affect the operability of equipment/systems located in close proximity to each other, interactions between normal offsite and emergency onsite AC power systems (e.g., sharing common breakers or power distribution buses), and common support systems, cross-connects, and other functional dependencies.

As discussed previously, the staff concluded that plant-specific analyses were necessary to accurately identify, evaluate, and resolve (where appropriate) vulnerabilities to systems interactions. The plant-specific IPE program[1222] includes an assessment of common cause or dependent failures. Since systems interactions are a subset of common cause failures, this concern is covered in the performance of the IPEs.

Issue A-47 also addressed aspects of this concern, including single failures or multiple failures which could cause a malfunction in one or more control systems. Such malfunctions may result in an undesirable control system response or provide misleading information to an operator. The analyses[1248] in support of the resolution of Issue A-47 identified potential control system failures that could cause overpressure, overcooling, overheating, overfilling, or reactivity events. All of these events are covered in DBA analyses. Requirements were established that, in general, provide or enhance systems to protect against reactor vessel/steam generator overfill events and to prevent steam generator dryout, enhance procedures and provisions to verify the operability of these systems, and modify selected procedures to respond to small-break LOCAs. This concern was considered to be resolved.

(4) Single Human Errors: This concern relates to the possibility that a single human error could potentially result in a plant transient or initiating event and defeat one or more divisions of a safety system. At the time of the initial evaluation of this issue in December 1991, no events of this type had been identified in plant operating experience, although the Davis-Besse incident was one that involved two human errors and a flawed Steam and Feedwater Rupture Control System. Therefore, it appeared unlikely that significant vulnerabilities to single human errors existed in the industry.

Issues A-17, A-44, A-45, and A-47 addressed various aspects of this concern as contributors to system failures, including degradation of operator information that could lead to operator "blindness," incorrect operator actions, and human errors. The analyses performed in support of these issues considered, for the most part, the possibility that single operator action could defeat one or more divisions of an ESF system. In addition, in situations where operator actions are necessary but the integrity of the information in the control room may be questionable (such as following a station blackout), it was assumed that the operator would not respond correctly. This effectively addressed single human errors that may defeat an ESF that otherwise would be operable.

Single human errors may also initiate a plant transient. Instances can be found in LERs in which single human errors have resulted in plant shutdowns, such as maintenance errors during electrical switchgear work that result in main feedwater isolation or interruption of vital AC power sources. Maintenance errors on the non-nuclear side of a plant that resulted in turbine-generator trips have also occurred. However, up to the time of this evaluation, such failures had not resulted in the occurrence of a transient and simultaneous failure of ESF systems

that are designed to respond to the transient. This was primarily because of the redundancy and diversity of plant systems, particularly ESF systems, that are designed to minimize the effects of single failures by maintaining separation of different divisions of vital plant equipment. This conclusion was supported by the results of a number of PRAs, including NSAC-60[889] and the PRAs prepared in support of NUREG-1150,[1081] in which no accident sequences initiated by single human errors were found to contribute significantly to core damage probability.

CONCLUSION

Since this issue was raised, all the safety concerns have been or will be adequately addressed in the resolution of Issues A-17, A-44, A-45, and A-47, the evaluation of Issue 117, the IPE program,[1222] and the Maintenance Rule.[1338] Thus, this issue was DROPPED as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

889. NSAC-60, "A Probabilistic Risk Assessment of Oconee Unit 3," Electric Power Research Institute, June 1984.

1081. NUREG-1150, "Reactor Risk Reference Document," U.S. Nuclear Regulatory Commission, December 1990.

1222. NRC Letter to All Licensees Holding Operating Licenses and Construction Permits for Nuclear Power Reactor Facilities, "Individual Plant Examination for Severe Accident Vulnerabilities - 10 CFR § 50.54(f), (Generic Letter No. 88-20)," November 23, 1988, (Supplement 1) August 29, 1989, (Supplement 2) April 4, 1990, (Supplement 3) July 6, 1990, (Supplement 4) June 28, 1991.

1232. NUREG-1174, "Evaluation of Systems Interactions in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, May 1989.

1233. NUREG-1229, "Regulatory Analysis for Resolution for USI A-17," U.S. Nuclear Regulatory Commission, August 1989.

1248. NUREG-1218, "Regulatory Analysis for Resolution of USI A-47," U.S. Nuclear Regulatory Commission, July 1989.

1323. Memorandum for W. Minners, et al., from F. Rowsome, "Generic Issue 123, 'Deficiencies in the Regulations Suggested by the Davis-Besse Incident,'" November 21, 1985.

1326. NUREG-1289, "Regulatory and Backfit Analysis: Unresolved Safety Issue A-45, Shutdown Decay Heat Removal Requirements," U.S. Nuclear Regulatory Commission, November 1988.

1338. Federal Register Notice 56 FR 31306, "10 CFR Part 50, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," July 10, 1991.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 128: ELECTRICAL POWER RELIABILITY

DESCRIPTION

Following the NRR reorganization in November 1985, EIB/DSRO was responsible for resolving three issues that were directly related to onsite electrical systems: Issue 48, "LCO for Class 1E Vital Instrument Buses in Operating Reactors"; Issue 49, "Interlocks and LCOs for Class 1E Tie Breakers"; and Issue A-30, "Adequacy of Safety-Related DC Power Supplies." In an effort to provide a more integrated approach to resolving these three issues, DSRO formulated a program to combine the issues into one generic issue.[1001] In addressing this issue, the staff was to consider NRC endorsement of IEEE Standards 603 and 308 with possible revisions to the related Regulatory Guides. Any revisions to Regulatory Guides resulting from this issue could impact future plants.

Issue A-30 was initiated because of concerns regarding the reliability of nuclear plant DC battery systems and the ability of plants to safely shut down in the event of a common mode failure or multiple failures of redundant systems. This concern resulted in a study of the safety-related DC power supplies at operating nuclear power plants. The results of this study were presented in NUREG-0305[163] which recommended that a quantitative reliability assessment of DC power systems be performed to identify and provide a basis for any changes in licensing criteria.

A reliability assessment was performed and documented in NUREG-0666.[164] The dominant failure modes identified in this study involved: (1) the inability of batteries to provide sufficient power to Class 1E instrumentation and controls buses upon loss of AC power to the battery chargers; and (2) operational, test, or maintenance errors that could result in the loss of multiple DC divisions. Monitoring provisions and procedures for preventing these occurrences were developed by the staff and presented in NUREG reports, Information Notices, Bulletins, and STS. Two of these provisions were adopted in industry standards: IEEE-450, "IEEE Recommended Practice for Maintenance, Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Substations," and IEEE-946, "Recommended Practices for the Design of Safety-Related DC Auxiliary Power Systems for Nuclear Power Generating Stations."

Issue 48 was identified when it was found that some nuclear power plants lacked administrative controls or TS governing operational restrictions for their Class 1E 120V AC vital instrument buses. These restrictions are required to ensure compliance with GDC 17, 21, 34, and 35 of 10 CFR 50, Appendix A. During repair or maintenance activities on bus power sources or inverters, one or more of the normal or alternate vital instrument bus power sources could be removed from service indefinitely. This condition could lead to the loss of more than one vital instrument bus in the event of a single failure or loss of offsite power.

Issue 49 was identified as a result of an incident at the Point Beach Nuclear Plant. The licensee reported to the NRC that a manually-operated tie-breaker between redundant safety buses, which had been closed during a plant outage in order to facilitate maintenance without interrupting power to affected systems, remained closed for a period of 5 weeks after the plant returned to operation.

In the event of a loss of normal AC power, the diesel generator output breakers would have been prevented from closing, as a result of the tie-breakers being closed.

CONCLUSION

This issue was given a high priority ranking and resolution was pursued based on the separate evaluations of Issues 48, 49, and A-30.

To address Issue A-30, Generic Letter No. 91-06[1399] was issued to request licensees to respond to 9 questions that were developed to facilitate staff determination of licensee implementation of existing recommendations. These recommendations included provisions for monitoring DC systems, test procedures, and operating procedures. The recommendations were identified from a number of previous and ongoing actions including industry standards, INPO recommendations, STS, and existing licensing practices. In the generic letter, the option was provided for licensees to supply information as part of the IPE. The actions described in the letter were not considered to constitute a backfit but only involved information gathering, in accordance with 10 CFR 50.54(f). Follow-up NRC actions, if necessary, were to be pursued on an individual plant basis.

Issues 48 and 49 were addressed in Generic Letter No. 91-11,[1400] issued to licensees to certify that they either have implemented TS or administrative controls conforming to the guidelines in the letter, or to justify why such controls may not be required. Any modification (e.g., procedural changes) performed to complete implementation would be considered a backfit to be performed as a compliance matter. This precluded evaluation of the need for controls as part of the IPE as an acceptable alternative to responding to Generic Letter No. 91-11.[1400] However, the option to further evaluate certain aspects (such as the optimum length of time for allowing outage of equipment) as part of the IPE was still provided.

The staff's technical findings were published in NUREG/CR-5414.[1401] Thus, this issue was RESOLVED and requirements were issued.[1402] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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163. NUREG-0305, "Technical Report on DC Power Supplies in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, July 1977.

164. NUREG-0666, "A Probabilistic Safety Analysis of DC Power Supply Requirements for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, April 1981.

1001. Memorandum for H. Denton from T. Speis, "Integration of Electrical Power Issues into Proposed Generic Issue 128, 'Electrical Power Reliability,'" November 28, 1986.

1399. NRC Letter to All Holders of Operating Licenses, "Resolution of Generic Issue A-30, 'Adequacy of Safety-Related DC Power Supplies,' Pursuant to 10 CFR 50.54(f) (Generic Letter 91-06)," April 29, 1991.

1400. NRC Letter to All Holders of Operating Licenses, "Resolution of Generic Issues 48, 'LCOs for Class 1E Vital Instrument Buses,' and 49, 'Interlocks and LCOs for Class 1E Tie Breakers,' Pursuant to 10 CFR 50.54(f) (Generic Letter 91-11)," July 18, 1991.

1401. NUREG/CR-5414, "Technical Findings for Proposed Integrated Resolution of Generic Issue 128, Electric Power Reliability," U.S. Nuclear Regulatory Commission, November 1989.

1402. Memorandum for J. Taylor from E. Beckjord, "Resolution of GI-128, 'Electrical Power Reliability,'" September 12, 1991.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 135: STEAM GENERATOR AND STEAM LINE OVERFILL

DESCRIPTION

Steam generator overfill and its consequences have received staff and industry attention because of the frequency and severity of overfill events. Over the years, a number of issues have been raised concerning steam generator overfill including Issue 66, "Steam Generator Requirements," and Issue 67, "Steam Generator Staff Actions." In order to provide an integrated work plan for the resolution of these issues, Issue 135 was initiated[1075] and assigned a medium priority ranking based on the separate evaluation of Issue 67.7.0, "Improved Eddy Current Tests."

Resolution of Issue 135 was expected to provide a better understanding of steam generator and secondary steam integrity, including the effects of water hammer on secondary system components and piping as well as the resultant radiological consequences. The work scope for resolving this issue was divided into four tasks which called for the following staff actions:

Task 1: (a) survey the code requirements and industry practice for eddy current testing procedures; (b) assess the capability of existing methods to detect steam generator tube degradation; (c) review existing ASME Section II requirements on eddy current testing procedures and determine its adequacy for use as a standard for inspection of steam generator tubes; and (d) develop written recommendations for regulatory guidance and/or requirements, including possible endorsement of ASME Section II requirements on eddy current testing procedures for development of a draft regulatory guide.

Task 2: Review the results and conclusions of studies on SGTR and propose specific modifications to SRP[11] Section 15.6.3 including tube integrity, operator action time, and offsite dose limits. Develop a regulatory analysis supporting the SRP[11] changes including a risk analysis and a cost benefit of the proposed changes.

Task 3: Reassess the following concerns in Issue 67 for potential inclusion in an integrated resolution: reassessment of radiological consequences; reevaluation of design basis SGTR; supplemental tube inspections; integrity of steam generator tube sleeves; denting criteria; improved accident monitoring; reactor vessel inventory measurement; RCP trip; control room design review; EOPs; organizational responses; and RCS pressure control.

Task 4: Review the effects of water hammer, overfill, and water carryover on the secondary system and connecting systems and develop proposals for mitigating the consequences. Consider the effects of sagging due to water weight, operability of valves, and other components when subjected to two-phase flow of liquid.

The coordination of results of the different tasks was to provide a basis for the staff to develop a position on offsite dose, operator action time, and tube integrity. Water hammer mitigation studies were to be carried out to give the staff a better understanding for developing positions on water hammer in main steam lines and operability of valves and other components.

CONCLUSION

This issue was given a medium priority ranking and pursued by the staff. It was found that SGTR and steam line overfill events pose a relatively low public risk, as previously indicated in NUREG-0844[681]; comparable risk results for SGTR events were also published in NUREG-1150.[1081] The staff technical findings were published in NUREG/CR-4893.[1411] Thus, this issue was RESOLVED and no new requirements were established.[1337] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

REFERENCES

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

681. NUREG-0844, "NRC Integrated Proyram for the Resolution of Unresolved Safety Issues A-3, A-4, A-5 Regarding Steam Generator Tube Integrity," U.S. Nuclear Regulatory Commission, September 1988.

1075. Memorandum for K. Kniel from R. Bosnak, "Integration of NUREG-0933 Issues," May 27, 1986.

1081. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Vol. 1) December 1990, (Vol. 2) December 1990, (Vol. 3) January 1991.

1337. Memorandum for J. Taylor from E. Beckjord, "Proposed Resolution and Closeout of Generic Issue 135, 'Steam Generator and Steam Line Overfill Issues,"' March 29, 1991.

1411. NUREG/CR-4893, "Technical Findings Report for Generic Issue 135," U.S. Nuclear Regulatory Commission, May 1991.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 138: DEINERTING OF BWR MARK I AND MARK II CONTAINMENTS DURING POWER OPERATIONS UPON DISCOVERY OF RCS LEAKAGE OR A TRAIN OF A SAFETY SYSTEM INOPERABLE

DESCRIPTION

Historical Background

The issue of deinerting upon discovery of RCS leakage was identified[1414] by DL/NRR, based on data collected by OIE. The related but separate concern of deinerting with one train of a safety system inoperable was also raised.

BWR MARK I and II containments are inerted with nitrogen during normal operations to protect against the build-up of a potentially explosive H_2-O_2 mixture, in the event of a LOCA or core damage event. Following a LOCA, H_2 is released within the containment from zircaloy-water reactions and H_2 and O_2 are also produced by radiolysis of the coolant. Core damage or melting would add an additional large quantity of H_2 as a result of metal/water reaction with fuel cladding and core structural materials. Plant atmosphere systems are designed to maintain containment O_2 concentration to less than 5% by volume, or the H_2 concentration to less than 4% by volume, to ensure that a combustible gas mixture does not form.

RCS leakage outside of TS limits requires licensees to identify, isolate, and repair the leak to avoid or mitigate the consequences of a LOCA. These steps require plant personnel entry into the containment. In accordance with plant TS, operators typically reduce power, deinert the containment, and allow personnel entry to identify potential RCS leaks. However, deinerting under leak conditions leaves the containment vulnerable to H_2-O_2 concentration build-up, if the leak progresses to a LOCA or core damage event. This was the primary concern in this issue. A secondary concern was that TS also allow licensees to operate with a deinerted containment for up to 24 hours with one train of a safety system inoperable.

The OIE data consisted of 13 RCS leak event reports in which the containment was deinerted to allow corrective action by plant personnel; these events occurred between 1981 and 1986. Existing NRC guidance for this issue included GDC 41 (Containment Atmosphere Cleanup), from 10 CFR 50 Appendix A, and Section 3.6.6.4 of the GE STS for BWR/5 designs.

Safety Significance

With either of the above concerns, the possibility of early gross containment failure with energetic source term release could be significantly increased, thereby increasing public risk. The issue affected 33 BWRs with MARK I or II containments.

Possible Solution

A possible solution to this issue was to revise plant TS to require a reactor to be brought to cold shutdown, prior to deinerting the containment, when either

unidentified leakage in the containment building or inoperability of a safety system is noted.

PRIORITY DETERMINATION

Frequency/Consequence Estimate

The baseline risk assessment used for this issue was the Millstone 1 PRA which was based on the assumption that the containment would always be inerted unless the reactor is in a cold shutdown condition; the PRA provided an assessment of risks associated with accident sequences at full power. In addition, the Millstone 1 PRA took into account TS allowing operations with one train of the safety system inoperable. The following two cases were assessed for this issue.

Case 1 — A deinerted containment during a shutdown for an unidentified RCS leak.

Case 2 — A deinerted containment with one train of a safety system inoperable.

For this issue, potential public risk reduction results from the change in containment failure mode afforded by not permitting deinerting during power operations under off-normal conditions. The assumed resolution of the issue will not result in a reduction of core-melt frequency.

To analyze the issue, an average consequence factor (C) was determined using the following equation:

$$R = f_{cm}\bar{C} = \Sigma f_{cmn} C_n$$

where
- R = Risk (man-rem/RY)
- f_{cm} = Core-melt frequency (event/RY)
- $\bar{C}$ = Average Consequence Factor (man-rem/event)
- f_{cmn} = Total core-melt frequency for the nth release category event/RY)
- C_n = Consequence Factor for the nth release category (man-rem/event)

The following values were used from the Millstone 1 PRA and NUREG/CR-2800:[64]

$f_{cm} = 3.09 \times 10^{-4}$/RY

$f_{cm1} = 1 \times 10^{-6}$/RY, $f_{cm2} = 8 \times 10^{-6}$/RY, $f_{cm3} = 1 \times 10^{-4}$/RY, $f_{cm4} = 2 \times 10^{-4}$/RY

$C_1 = 5.4 \times 10^6$ man-rem, $C_2 = 7.1 \times 10^6$ man-rem, $C_3 = 5.1 \times 10^6$ man-rem, $C_4 = 6.1 \times 10^5$ man-rem

Therefore, the value of $\bar{C}$ was 2.25×10^6 man-rem/event.

From the Millstone 1 PRA, the only dominant LOCA sequence was found to be the small-break LOCA ($SB_{(B)}$). The frequency of $SB_{(B)}$($fSB_{(B)}$) was 3×10^{-6} event/RY.

In analyzing the first concern, i.e., deinerting the containment with an unknown leakage into the containment building, two different schools of thought concerning the effect of detected leakage upon LOCA expected frequency were

addressed. Employing the leak-before-break theory, detection of leakage within the containment building would not be associated with an increase in LOCA frequency. Conversely, it could be assumed that leakage from a through-wall pipe crack would increase the probability that the pipe would break causing a LOCA. As a result, the unknown leakage concern was analyzed from both perspectives as Case 1.

It was assumed that, whenever the containment building is deinerted, any core-melt event will result in containment failure due to H_2 burn with a probability of 1. TS permit licensees to deinert the containment building of BWR MARK I and II designs, 24 hours prior to a scheduled shutdown. LERs gathered over the 5-year period revealed 9 events in which the plants were deinerted before reaching a hot shutdown condition and one event in which the plant was deinerted before shutdown with one train of ECCS inoperable. Of the 9 leakage events, 8 were found to be valve stem, body packing, or seal failures and one was determined to be a through-wall crack in a RCS line. Assuming that the containment was deinerted for 24 hours during plant operation for each of these events and that during the five-year period 29 plants operated with an assumed power production factor (i.e., historical fraction of the calendar-year that plants operate at or near full power) of 0.7, the following fractions of plant operating history were calculated. Each represents the fraction of the operating history that a plant experiences a deinerted condition, as a result of the particular set of circumstances:

V_a - deinerted due to unknown leakage (9 events) $= 2.4 \times 10^{-4}$

V_b - deinerted due to unknown leakage actually due to through-wall pipe leak (1 event) $= 2.7 \times 10^{-5}$

V_c - deinerted due to unavailability of one train of a safety system (1 event) $= 2.7 \times 10^{-5}$

Assuming that, if the containment is deinerted and a core damage event occurs, the conditional probability of containment failure (F_{con}) due to H_2 explosion is 1, the conditional probability of containment failure becomes the probability that the containment is deinerted (V_n). The consequence of containment failure due to H_2 explosion in the Millstone 1 PRA is best represented by the consequence factor (C_2) for a Category 2 release, i.e., early large containment failure. Therefore, the risk during periods while the plant is deinerted in preparation for a shutdown with an unknown leakage, assuming that detection of leakage does not increase the probability of a pipe break (LOCA), was calculated as follows:

$$r = f_{cm} V_a F_{con} C_2$$
$$= (3.1 \times 10^{-4})(2.4 \times 10^{-4})(1)(7.1 \times 10^{6}) \text{ man-rem/RY}$$
$$= 0.528 \text{ man-rem/RY}$$

This was the base case risk. If plants are not permitted to deinert during periods of unknown leakage in the containment building, the adjusted case risk would be:

$$r' = f_{cm} V_a \bar{C}$$
$$= (3.1 \times 10^{-4})(2.4 \times 10^{-4})(2.25 \times 10^{6}) \text{ man-rem/RY}$$
$$= 0.167 \text{ man-rem/RY}$$

The change in risk (Δr) is ($r - r'$) or 0.361 man-rem/RY. When applied to the 33 affected plants with an average remaining life of 18.6 years, the total risk

reduction attainable by not permitting plants to deinert when an unidentified source of leakage in the containment building exists was estimated to be 222 man-rem.

If it is assumed that the probability of a LOCA (in this case $SB_{(B)}$) is increased by two orders of magnitude if a through-wall leak exists, the potential risk reduction afforded by not permitting plants to deinert when an unidentified source of leakage in the containment building exists is calculated as follows:

$$r = f_{cm}(V_a - V_b)F_{con}C_2 + (f_{cm})'V_bF_{con}C_2$$

where $[fSB_{(B)}]' = fSB_{(B)} \times 100 = 3.10 \times 10^{-4}$/RY

$[f_{cm}]' = f_{cm} - fSB_{(B)} + [fSB_{(B)}]' = 6.08 \times 10^{-4}$/RY

Thus, the base case risk (r) was 0.585 man-rem/RY.

If deinerting is not allowed when there is an unknown leakage in the containment building, the adjusted case risk is calculated as follows:

$$r' = f_{cm}(V_a - V_b)\overline{C} + (f_{cm})'V_b\overline{C} = 0.186 \text{ man-rem/RY}$$

Thus, the change in risk due to resolution of this aspect of the issue is (0.585 - 0.186) man-rem/RY = 0.399 man-rem/RY. When applied to the 33 affected plants with an average remaining life of 18.6 years, the potential risk reduction due to resolution, if it is assumed that through-wall leakage increases the probability of LOCA by two orders of magnitude, is 245 man-rem.

The second case, i.e., containment deinerting prior to shutdown with a train of a safety system inoperable, was analyzed as follows. The LER data from the 5-year study period revealed only one instance of deinerting prior to shutdown with a train of a safety system (LPS in this case) inoperable. This results in a fraction of operating history for this condition $V_c = 2.7 \times 10^{-5}$ as shown earlier. It was conservatively assumed that unavailability of one train of any safety system will increase the core-melt frequency by one order of magnitude, i.e., $(f_{cm})^z = 3.1 \times 10^{-3}$/RY.

The base case risk (r_z) was calculated by the following relationship:

$$r_z = (f_{cm})^zV_cF_{con}C_2$$

$$= (3.1 \times 10^{-3})(2.7 \times 10^{-5})(1)(7.1 \times 10^6) \text{ man-rem/RY}$$
$$= 0.594 \text{ man-rem/RY}$$

If resolution of the issue does not permit deinerting with one train of a safety system inoperable, the adjusted case risk r_z' is calculated from the following relationship:

$$r_z' = (f_{cm})^zV_c\overline{C}$$

$$= (3.1 \times 10^{-3})(2.7 \times 10^{-5})(2.25 \times 10^6) \text{ man-rem/RY}$$
$$= 0.188 \text{ man-rem/RY}$$

Thus, the change in plant risk for this case due to resolution of the issue is $(r_z - r_z') = (0.594 - 0.188)$ man-rem/RY = 0.406 man-rem/RY. When applied to the

affected population of 33 plants over the average remaining life of 18.6 years, the potential risk reduction attainable by not permitting deinerting with one train of any safety system inoperable is 249 man-rem.

Cost Estimate

Industry Cost: Industry costs included preparation and implementation of TS changes for the affected plants and replacement power costs that would be incurred because TS eliminating deinerting prior to shutdown under off-normal conditions will lengthen plant outages by up to 24 hours per shutdown. At $18,000/ plant, the total industry cost for simple TS changes was estimated to be $594,000.[961]

Assuming that each time a plant must shut down for an unidentified leak in the containment building and/or a safety system train inoperable not allowing the 24-hour deinerting period will add one day to the plant outage, the average replacement power cost was estimated to be $300,000/day for each instance. Ratioing the 9 containment leakage events and the 1 loss of a safety system train event from the 5-year survey of LERs, it was determined that for the 33 affected plants over their remaining life of 18.6 years, 38 leakage events and 4 safety system train events would be expected. This equates to an industry replacement power cost of $12.6M ($11.4M for leakage events and $1.2M for loss of a safety system train events).

Thus, the total estimated industry costs were $12M and $1.8M for the leakage and safety system inoperability aspects of the issue, respectively.

NRC Cost: Resolution of either or both parts of this issue will require the issuance of a backfit order and the development, review, and approval of a revised TS for each of the affected plants. Development and approval of the resolution of the issue was estimated to require a staff effort of $100,000 and a technical assistance contractual effort of $250,000, for a total of $350,000. Imposition and implementation of the resolution of the issue, i.e., review and approval of a simple TS change, were estimated to be $11,000/plant, and $363,000 for the 33 affected plants. Thus, the total NRC cost was estimated to be $713,000.

Total Cost: For Case 1, the total industry and NRC cost associated with the possible solution is $(12 + 0.713)M for leakage events and loss of a safety system train events. For Case 2, the total industry cost is $(1.8 + 0.713)M.

Value/Impact Assessment

Separate value/impact scores were calculated for each case.

(1) Case 1 - Leakage Only

(a) Based on no increased probability of LOCA,

$$S = \frac{222 \text{ man-rem}}{\$12.7M}$$

$$= 17.5 \text{ man rem/\$M}$$

(b) Based on two orders of magnitude increase in LOCA probability,

$$S = \frac{245 \text{ man-rem}}{\$12.7M}$$

$$= 19.3 \text{ man-rem/\$M}$$

(2) Case 2 - Safety System Train Inoperable

$$S = \frac{249 \text{ man-rem}}{\$2.5M}$$

$$= 99.6 \text{ man-rem/\$M}$$

Other Considerations

License Renewal: The remaining life of the plants used to calculate the risk, cost, and value/impact scores was based on the assumption that the total operating life of the existing operating plants was limited to 40 years. The potential for license extension was also considered with the assumption that 75% of existing operating plants would apply for license extensions of 20 years.

The additional risk reduction increment from license extensions would not result in a total potential risk reduction of more than 500 man-rem for either aspect of this issue. Since both the risk reduction estimates and the licensee costs estimates were a direct function of remaining plant operating life, the value/impact scores remain essentially unchanged by consideration of license extension.

CONCLUSION

Whether considered for the remaining licensed lifetime of BWR MARK I and II plants or for additional operating life through license extension, the value/impact scores and potential risk reduction for both the leakage and safety system train inoperability aspects of the issue fall into the LOW priority category (See Appendix C). Consideration of a 20-year license renewal period did not change the priority of the issue.[1564]

REFERENCES

961. NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986.

1414. Memorandum for K. Kniel from G. Lainas, "Proposed Generic Issue Deinerting Upon Discovery of Reactor Coolant System Leakage," August 1, 1986.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications for Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 139: THINNING OF CARBON STEEL PIPING IN LWRs

DESCRIPTION

Historical Background

This issue was raised[1089] as a result of a pipe rupture in the main feedwater (MFW) system at the Surry Unit 2 nuclear power plant on December 9, 1986. The MFW pipe rupture followed a reactor trip from full power shortly after the unit returned to operation on December 8, 1986, following a scheduled refueling outage. The staff presented briefings on the incident to the Commission on February 25, 1987, and to the ACRS at its 322nd Meeting on February 5, 1987.

The Surry pipe rupture was in the 18-inch "A" MFW pump suction line immediately downstream of a compound 90° elbow and T-section connecting the 18-inch pipe to the 24-inch condensate header. The rupture was a catastrophic, 360° circumferential break. A piece of the ruptured pipe (approximately 4 feet by 2 feet in size) was blown some distance from the break point. The piping still attached to the pump suction rotated away from the break point and came to rest against a portion of the "B" MFW pump discharge piping. No significant damage to the "B" MFW pump was noted.

The failed 18-inch suction line was fabricated from ASTM A-106 Grade B carbon steel and ASTM A-234 Grade WPB carbon steel wrought fittings with a nominal wall thickness of 0.5 inches. Visual inspections of the inside surface of the elbow revealed a dimpled surface and general pipe wall thinness as small as 0.05 inches. Ultrasonic thickness measurements indicated the wall-thinning to be a gradual change over most of the elbow fitting. The licensee concluded that the pipe ruptured because of the thinned wall and that the thinning was a result of erosion/corrosion.

On January 15, 1987, the Honorable Edward Markey (U.S. House of Representatives) requested the GAO to assess NRC actions following the Surry event and several other technical problems at nuclear power plants. The GAO assessment[1090] of actions taken related to the Surry event and similar piping deteriorations detected at other LWRs was issued in March 1988. The major GAO conclusions and recommendations are provided in the conclusion of this analysis.

A similar pipe rupture occurred at the Trojan plant following a reactor/turbine trip on March 9, 1985 (See LER 85002, Docket No. 5000344). The pipe rupture at the Trojan plant was in the 14-inch heater drain pump discharge line immediately downstream of a globe valve leading to the condensate header and MFW suction side. The piping was the same ASTM A-106 Grade B material with a required minimum wall thickness of 0.375 inches. The wall thickness in the region of the rupture was thinned to approximately 0.1 inches and the cause was attributed to wall-thinning by erosion/corrosion.

In both events, the fluid medium was single-phase, subcooled water at nominally 350°F and 450 psi. Water velocities were in the range of 20 to 40 fps and the

flow in the ruptured locations was subject to turbulence induced by piping and fitting configurations, with pressure increases resulting from automatic MFW isolation.

Historically, erosion/corrosion in nuclear and fossil plants has occurred primarily in wet steam (two-phase) lines and has not been reported in dry steam lines (EPRI NP-5410).[1092] The erosion/corrosion in single-phase (water) systems was not expected and differs in the mechanisms contributing to the process, being a complex phenomenon dependent on many variables such as alloy content, temperature, Ph, and flow velocities and perturbations caused by piping and fitting configurations.

Following the Surry event, the staff issued a series of Information Notices informing the industry of the Surry pipe rupture. On July 9, 1987, the staff issued NRC Bulletin No. 87-01[1093] requesting licensees to submit information concerning their programs for monitoring the thickness of pipe walls in high-energy, single- and two-phase, carbon steel piping systems.

Staff review of the licensees' responses to Bulletin 87-01[1093] were reported in SECY-88-50[1094] and Information Notice No. 88-17.[1095] A staff report on the status of the industry erosion/corrosion program was provided in SECY-88-50A.[1096] For two-phase, high-energy, carbon steel piping systems, responses indicated that licensees had programs at all plants for inspecting pipe wall-thinning. However, because the guidelines were not required to be implemented, the scope and extent of the programs varied significantly from plant to plant.

For single-phase piping systems such as in the feedwater/condensate lines, a limited number of inspections were conducted following the Surry event. Based on the Bulletin[1093] responses up to the time this issue was evaluated in November 1988, 23 out of a total of 110 units had not established an inspection program for the single-phase lines. Of these units, 17 were operating plants and 6 were under construction.

The staff review[1091] showed that wall-thinning in the feedwater/condensate systems was more prevalent in PWRs than in BWRs. The review indicated that licensees of 27 PWRs and 6 BWRs identified various degrees of wall-thinning in feedwater piping and fittings. The pipe wall-thinning problem was widespread for single- and two-phase, high-energy, carbon steel piping systems in PWR and BWR plants. Since the problem was more prevalent in PWRs, this analysis focused on PWR plants. However, due to the nature of the problem, the resolution indicated that the issue related to all LWRs.

Safety Significance

There were no requirements for the industry to have an inspection program for monitoring and examining the ASME minimum wall thickness for carbon steel piping. Therefore, even though a pipe break is a design basis event for which plants are designed, the potential frequency of such breaks was higher than previously anticipated. Lacking inspection requirements to provide assurance of the defense-in-depth against catastrophic pipe ruptures in the secondary power conversion systems (and specially the feedwater/condensate systems), plants may not have adequate assurance that they meet the design basis life.

The higher pipe rupture frequencies could also introduce additional challenges to safe plant shutdown from potential systems interactions of the high-energy steam/water releases that may damage, or affect, other systems (see "Systems Interactions from Pipe Ruptures" below). Thus, risks from design basis pipe ruptures that did not account for erosion/corrosion wall-thinning in the secondary piping systems may be greater than previously evaluated.

Possible Solution

The staff was continuing its review of pipe wall-thinning and was expected to assess the results obtained from inspections to be performed during the 1988 Spring refueling outages.[1094,1096] This assessment included visiting up to ten plants to review their inspection methods and results. The staff anticipated that its review would be completed by December 1988 and could, if necessary, provide the basis for new requirements[1094,1096] in single- and two-phase carbon steel piping systems.

A possible solution for the single-phase piping systems, which unlike the two-phase systems that have existing monitoring programs, might include inspections to be conducted at each refueling outage. However, for the long term solution, the staff planned to continue working with NUMARC and EPRI to arrive at an implementation program and schedule for the resolution of pipe wall-thinning in both single- and two-phase carbon steel piping systems.

PRIORITY DETERMINATION

Pipe ruptures from erosion/corrosion-induced wall-thinning of carbon steel piping had not been reported prevalent in dry-steam lines[1092] such as the main steam lines. Two-phase piping lines, such as the turbine crossover/under piping and steam extraction lines, had experienced erosion/corrosion wall-thinning and ruptures even though licensees had monitoring and inspection methods (though not required) in place to various degrees for some time. This indicated that improvements were needed in the existing inspection programs to provide timely detection of the piping degradations.

Single-phase carbon steel piping runs, which were not believed to be susceptible to erosion/corrosion wall-thinning, were not in general (prior to the Surry event) monitored or inspected for potential wall-thinning. The single-phase systems in the secondary power conversion systems which had been found to be susceptible to wall-thinning were the feedwater/condensate systems and the high pressure feedwater heater drain pump discharge piping lines. These single-phase lines transport water at a nominal temperature of 350°F and water velocities ranging from 20 to 40 fps. Both of these conditions tend to exacerbate the erosion/corrosion phenomenon in carbon steel piping systems carrying single-phase fluid (water).

AFW piping lines that typically draw water at lower temperatures from the condensate storage tank, and do not experience continuous flow during power production, had not been reported to be susceptible to erosion/corrosion wall-thinning. Because it was difficult to determine the effectiveness of the two-phase piping systems inspections, lacking information on previous repairs and replacements resulting from the inspections, the two-phase rupture frequency was assumed equivalent to the single-phase carbon steel piping rupture frequency

estimated below. Without existing inspections, the two-phase piping systems would be expected to have a higher rupture frequency.

As stated above, this analysis focused on evaluating the carbon steel wall-thinning pipe ruptures in single-phase piping systems and the wall-thinning ruptures in two-phase piping systems of PWR power conversion systems. Based on existing inspection results, BWRs appeared to have a similar problem, but to a lesser degree. Therefore, this analysis bounded the issue for all LWRs.

Recovery of Power Conversion Systems

The power conversion systems feed into one another through various piping configurations, including straight lines or headers and various valving or fitting arrangements. Therefore, a rupture in either the single- or two-phase piping systems could disable the PWR power conversion systems to various degrees. Thus, the probability of recovering the power conversion systems was uncertain. Therefore, it was conservatively estimated that the probability of non-recovery of the power conversion systems (PCSNR) was 0.5, given a rupture in the secondary systems.

Carbon Steel Pipe Rupture Frequency

The data on erosion/corrosion-induced wall-thinning resulting in ruptures of carbon steel piping carrying single-phase fluid was limited to the Surry and Trojan events described earlier. This limited data was used to estimate upper and lower bounds of the subject pipe rupture frequency.

For the upper bound estimate, the plant-specific experiences of Surry and Trojan were used. At the Trojan plant, the pipe rupture occurred after approximately 9 years of operation. At the Surry plant, the pipe rupture occurred after approximately 14 years of operation. This data yielded an upper bound rupture frequency of 9×10^{-2}/RY. For the lower bound estimate, the two pipe ruptures were ratioed over the total number of PWR reactor-years of operation (approximately 600 RY). This yielded a lower bound estimate of 3.3×10^{-3}/RY.

The rupture frequency was approximated by a log normal distribution with an error factor of five and the upper and lower bounds were assumed as two symmetrically located percentiles (0.05 to 0.95) of a log normal distribution. The calculated mean rupture frequency was 3×10^{-2}/RY. As stated earlier, it was assumed that the rupture frequency of 3×10^{-2}/RY was applicable to the secondary side carbon steel piping systems identified herein.

Most of the pipe ruptures that might occur in the non-safety-related portions of the secondary systems are likely to be outside of containment because most (90%) of the secondary side piping is located outside containment. Pipe ruptures in the safety-related portion of the MFW piping inside containment can result in the secondary side of the affected steam generator blowing down to the containment atmosphere. For these lower frequency ruptures, $(0.1)(3 \times 10^{-2}) = 3 \times 10^{-3}$/RY, isolation of AFW to the affected steam generator will reduce the chance of containment overpressurization from continued long-term steaming due to decay heat from the reactor core. Automatic AFW isolation is necessary to ensure that the containment design pressure will not be exceeded. This event, like other ruptures that may occur in the PWR power conversion systems, was treated as a total loss of main feedwater. This sequence was bounded by the TMLU rupture event

sequence described below. However, pipe ruptures inside containment are less likely and will not likely induce the negative systems interaction problems that can result from pipe ruptures outside containment.

Systems Interactions from Pipe Ruptures

Communication Systems Failures: During the MFW pipe rupture at the Surry plant, the Cardox and Halon fire suppression systems were actuated by steam/water intrusion into their control panels. The security repeater which was located approximately five feet from a Cardox discharge nozzle failed and was later found to be covered with a thick layer of ice. As a result, security communications were temporarily limited to the non-repeater hand-held radios. Therefore, actuation of the Surry fire protection system (FPS) resulted in loss of a train of the communication systems.

Given that loss of one train of plant communications occurred in one of the two pipe rupture events, the probability that failure of this train of communication can occur as a result of pipe ruptures in the secondary systems outside containment was estimated to be 0.5.

To estimate the probability of loss of the backup hand-held communication radios, the following were assumed: probability of battery failure = 0.1; probability of operator error in not replacing the batteries = 0.1; and probability that other units are not readily available = 0.1. The probability of loss of both communication systems, given a pipe rupture in the secondary systems outside containment, was estimated to be 5×10^{-4}.

To estimate the impact of the loss of plant communication systems, it was assumed that loss of communications would increase operator errors in the four event sequences affected by the pipe rupture. Based on an examination of the fault trees[54] for the four sequences, and adjusting the operator errors to account for loss of communications, the percentage increase in core-melt frequency for each sequence was estimated as follows:

Loss of Communications

Sequence	% Increase In Sequence Core-Melt Frequency
TMQH	7
TMKU	negligible
TML(PCSNR)U	7
TMQD	2

Actuation of FPS: Within minutes of the MFW pipe rupture at Surry, 62 sprinkler heads opened in the immediate area of the rupture. As a result of the sprinkler water and the feedwater discharge, the Cardox and Halon suppression systems control panels were affected by intrusion of steam/water. The intrusion caused the time limit, battery charger, and the dual zone modules to short. Thus, the manual remote actuation circuit located in the control room was affected.

In Issue 57, the effects of actuation of the FPS actuation and the potential increases to core-melt frequency were estimated; the sequence evaluated was the TMLU sequence and the safety system evaluated was the AFW system. Because one of the two pipe rupture events (Surry and Trojan) affected the FPS manual remote

control, the estimates in Issue 57 were adjusted by assigning a probability of 0.5 to failure of the FPS manual control. With this adjustment, the increase in unavailability of the AFW system, given actuation of the FPS water deluge system, was estimated to be 2×10^{-5}. Assuming typical AFW unavailability of 5×10^{-5} (discussed later), the combined AFW unavailability, given actuation of the FPS, was 7×10^{-5}.

Using the same 2×10^{-5} increased unavailability for other safety systems in the event sequences of this issue, no significant effect was found because the other safety systems were less sensitive to the 2×10^{-5} estimate. This conclusion was consistent with the Issue 57 assessment.

Electric Door Lock Failures: At the time of the Surry pipe rupture event, water and steam saturated a security card-reader located approximately 50 feet from the break point. As a result, key-cards would not open plant doors. The control room doors were opened to provide access to the control room and security personnel were assigned to the control room to provide the access security. One operator was temporarily trapped in a stairway due to the card-reader failure. At the time of this evaluation, the Surry plant was considering installing electric override switches to remedy this problem.

In Issue 81, the impact of the electric lock (card-reader) failure at Surry was evaluated. The results from Issue 81 indicated that failure of electric locks, without override protection, may contribute approximately 2% to core-melt accidents from pipe ruptures outside containment.

Frequency Estimate

To estimate the core-melt frequency from ruptures in PWR secondary systems, an example PRA[54] was used together with additional information provided in NUREG/CR-2800.[64] The pertinent accident sequences were then adjusted to account for pipe ruptures in the secondary side of PWR plants. The accident sequences used in this analysis were TMQD, TMKU, TMQH, and TML(PCSNR)L where:

TM - a loss of power conversion system (PCS) transient caused by other than loss-of-offsite power. For this analysis, TM corresponds to the secondary system pipe rupture frequency (3×10^{-2}/RY) resulting in loss of the main feedwater system (M = 1);

Q - the pressurizer safety/relief valve demanded opens (0.01) and any pressurizer safety/relief valve fails to re-close (0.05);

D - failure to provide sufficient ECCS injection (10^{-3});

K - failure of the RPS (2.6×10^{-5});

H - failure of the ECCS recirculation system (7×10^{-3});

PCSNR - failure to recover the PCS (0.5, as discussed earlier);

U - failure of the operator to start high pressure injection, or feed-and-bleed is initiated, but is unsuccessful. For this analysis, U = 0.2 was assumed;

L - failure of the AFW system. For 3-train AFW system plants, a typical AFW unavailability was 1.8×10^{-5} /demand. For 2-train AFW system plants, the goal of Issue 124 was to upgrade the AFW systems to 10^{-4}/demand. Therefore, a typical value of 5×10^{-5}/demand was used in this analysis.

Table 3.139-1 includes the sequences with and without the effects of systems interactions from pipe ruptures in the secondary systems outside of containment. Examination of the results indicate that collectively the systems interactions may increase the core-melt frequency from pipe ruptures in the secondary systems outside containment by approximately 20% (9×10^{-8}/RY). The total core-melt frequency, with the systems interactions (SI) effects included, was estimated to be 5×10^{-7}/RY.

TABLE 3.139-1

Sequence	Without (SI)	Communications (SI)	FPS (SI)	Locked Doors (SI)	TOTAL
TMQD	1.50×10^{-8}	3.00×10^{-10}	neg.	3.0×10^{-10}	1.56×10^{-8}
TMKU	1.50×10^{-7}	neg.	neg.	3.0×10^{-9}	1.53×10^{-7}
TMQH	1.05×10^{-7}	7.40×10^{-9}	neg.	2.1×10^{-9}	1.15×10^{-7}
TMLU	1.50×10^{-7}	1.05×10^{-8}	6×10^{-8}	3.0×10^{-9}	2.24×10^{-7}
SUM	4.20×10^{-7}	1.80×10^{-8}	6×10^{-8}	8.4×10^{-9}	5.00×10^{-7}

Consequence Estimate

The core-melt sequences under consideration involve no large breaks initially in the reactor coolant system pressure boundary. The reactor is likely to be at high pressure until the core melts through the lower vessel head with a steady discharge of steam and gases through the PORV(s). These are conditions that may produce significant H_2 generation and combustion.

For these sequences, a 3% probability of containment failure due to H_2 burn and a 1% probability of containment isolation failure were used. If the containment does not fail by H_2 burn or isolation failure, it was assumed to fail by basemat melt-through.

The conditional releases for these containment failure modes had a weighted average core-melt release of 1.7×10^5 man-rem. The calculated releases were based on a core inventory typical of a 1120 MWe plant, a uniform population density of 340 persons per square mile from an exclusion area of one-half mile out to a 50-mile radius from the plant, no evacuation of people, no injestion pathways, and meteorology typical of a midwest site.

The annual public risk from secondary side piping ruptures due to wall-thinning was the product of the core-melt frequency (5×10^{-7}/RY) and the weighted average

release (1.7×10^{-5} man-rem). Therefore, the public risk was 8.5×10^{-2} man-rem /RY. Assuming a remaining plant life of 30 years, the cumulative public risk was 3 man-rem/reactor.

Cost Estimate

Industry Cost: A possible solution for early detection of wall-thinning in carbon steel piping in the secondary systems was to implement and conduct inspection programs for these systems during each refueling outage. A report was prepared by EPRI[1092] to provide guidance to the industry for conducting NDE of ferritic piping systems for wall-thinning caused by erosion/corrosion in nuclear and fossil power plants. The EPRI report contained the results of investigations of various NDE methods that may be applicable to the detection of erosion/corrosion effects. EPRI reported that virtually all plants used manual ultrasonic thickness measurements. Four utilities had performed automated ultrasonic thickness measurements from the outside surface of the piping. One EPRI source reported that an automated examination would cost approximately $50,000 and take one week, whereas a manual team of two operators could perform the examination in one afternoon. Therefore, the cost of the manual inspection was estimated to be $10,000 per outage.

The difference noted by EPRI was that the manual team would acquire data on a 4-inch grid pattern and the automated system could acquire data continously over the entire surface. Additional setup time was also required for the automated system. Therefore, the above $10,000 cost for the manual inspection could have been overestimated.

An additional cost associated with the inspections was the removal and disposal of asbestos insulation and re-insulation. These costs were reported to range from $300,000 to $750,000 per outage. In some plants, asbestos insulation was programatically being removed due to strict state and local guidelines associated with health hazards to workers from asbestos.

Approximately half (44) of the 92 plants contacted in the EPRI survey had asbestos insulation. Thirty-two of the forty-four had at least partially replaced asbestos with other insulation, or were planning to remove the asbestos, and the remaining twelve plants were undecided.

Based on the above, any NRC requirement to conduct NDE inspections at each refueling outage could provide an additional incentive for the 12 plants (13% of all plants) to remove and replace the asbestos insulation with other types of insulation. Therefore, on an average, the industry costs to remove and dispose of the asbestos insulation to facilitate NDE inspections was estimated to be a one-time cost of (0.13)($750,000 + $300,000)/2 = $68,000/plant. However, the argument could be made that the cost of asbestos removal could be driven by the state and local requirements, and not by NRC inspection requirements.

Assuming a remaining plant life of 30 years and a typical time between refueling outages of 1.5 years, the cumulative number of inspections that may be conducted during each refueling outage for each plant was 20. The annual cost over 30 years was (20)($10,000)/30 = $6,700/plant. The present value of the NDE annual costs over 30 years, considering a 5% discount rate, was approximately $100,000/plant. The combined one-time costs for asbestos insulation removal and disposal and the sent value NDE cost over 30 years is $168,000/plant.

NRC Cost: It was estimated that one man-year of effort may be needed to reach a staff position on this issue and an additional man-year of effort to develop a Regulatory Guide or SRP Section. Assuming $100,000/man-year, the NRC costs were estimated to be $200,000. When distributed over approximately 100 plants, this cost was $2,000/plant.

Total Cost: The combined industry and NRC cost for the possible solution was estimated to be $170,000/plant.

Value/Impact Assessment

Based on the estimated risk reduction of 3 man-rem/reactor and implementation costs of $170,000/plant for the possible solution (NDE examinations at each plant refueling outage), the value/impact score was given by:

$$S = \frac{3 \text{ man-rem}}{\$0.17M}$$

$$= 17.6 \text{ man-rem/\$M}$$

Other Considerations

Accident Avoidance Cost: The present value of onsite property damage conditional on a core-melt for a remaining plant life of 30 years, assuming a 5% discount rate, was $20 billion. For a core-melt frequency of 5×10^{-7}/RY attributed to pipe ruptures in the secondary systems, the accident avoidance cost by eliminating or significantly reducing the probability of pipe ruptures was $10,000/plant.

Industry Rupture Avoidance Cost: The rupture avoidance costs are the plant costs estimated to result from a pipe rupture in the secondary systems, assuming the plant responds as designed and no core-melt from potential equipment failures ensues. For a pipe rupture frequency of 3×10^{-2}/RY, the chance of a pipe rupture in the secondary side can approach unity over the life of a plant.

To estimate the costs of plant repairs after a forced outage from a pipe rupture in the secondary system, historical plant operational data indicates that a best estimate repair cost from forced outages for a typical nuclear power plant is approximately $1,000/hour.[1082] The Trojan plant outage time following a pipe rupture in the secondary system was 6 days, whereas the Surry plant outage time lasted approximately 90 days. Based on the above, the plant repair costs from these two events was estimated to range from $140,000 to $2M. The replacement power costs resulting from the forced outages of 6 days for the Trojan plant and 90 days for the Surry plant were $3M and $45M, respectively; the cost of replacement power was estimated at $500,000/day.

It was assumed that the above cost estimates reflected lower and upper bound costs that could be represented by a log normal distribution with an error factor of 4. The combined repair costs and replacement power costs, adapted to a log normal distribution, yielded an estimated value of $17M as the mean plant costs resulting from a pipe rupture in the secondary systems.

The $10,000/plant accident (core-melt) avoidance costs were small compared to the estimated rupture avoidance costs of $17M/plant. The low core-melt frequency of

5×10^{-7}/RY drove down the accident avoidance costs. However, based on the estimated pipe rupture frequency of 3×10^{-2}/RY, the chance of a pipe rupture in the secondary systems over the life of a plant approaches unity. Thus, the rupture avoidance costs dominated the combined accident and rupture avoidance costs.

When the implementation cost ($170,000/plant) is offset by the accident and rupture avoidance costs (a $17M/plant cost savings), the denominator of S becomes negative. The negative denominator of approximately $17M/plant indicates a substantial potential cost savings (industry incentive) by avoiding piping ruptures in the secondary systems.

Occupational Safety: Erosion/corrosion-induced ruptures in high energy carbon steel piping lines described in this analysis resulted in injury and fatalities to plant personnel and contractor employees working in the area of the ruptures. At the time of the Surry pipe rupture, 8 contractor employees were working in the area of the pipe rupture; 6 of these individuals were hospitilized for treatment of severe burns and 2 were treated at a clinic and released. Four of the severely burned individuals died and the other two were in serious to critical condition. One of the two remained in serious condition for more than a month after the accident. Following the pipe rupture at the Trojan plant, one member of the plant operating staff received first and second degree burns and was treated at a local hospital over a three-week period.

CONCLUSION

The estimated core-melt frequency of 5×10^{-7}/RY and the potential risk reduction of 3 man-rem/reactor indicated that pipe ruptures in the PWR secondary systems from erosion/corrosion-induced wall-thinning is of low safety significance to the public. Since inspection results indicated that erosion/corrosion wall-thinning of carbon steel piping is less prevalent in BWR plants, the above PWR risk estimates should be bounding. Therefore, as a generic safety issue, this issue would have been given a low priority ranking. However, the erosion/corrosion-induced wall-thinning of carbon steel piping in secondary systems was not expected to be a significant cause of pipe ruptures. Pipe ruptures were more generalized as limiting faults: postulated, but not expected to occur. Thus, knowledge and an understanding of this phenomena was limited. This analysis indicated that, without adequate defensive methods or measures, pipe rupture induced by wall-thinning can be expected within the lifetime of a plant: an infrequent event with a higher frequency than the limiting fault (postulated) pipe ruptures.

The GAO concluded that the Surry accident initiated a new era of understanding regarding erosion/corrosion at nuclear power plants and demonstrated that unchecked erosion/corrosion can lead to a fatal accident. The GAO also concluded that NRC needed a mechanism to ensure that utilities periodically assess the integrity of piping systems to reduce the risk of future injury to plant personnel or damage to equipment caused by erosion/corrosion. The GAO recommended that NRC require utilities to:

(1) inspect all nuclear plants to develop data regarding the extent that erosion/corrosion existed in piping systems, including straight sections of pipe;

(2) replace piping that did not meet the industry's minimum allowable thickness standards; and

(3) periodically monitor piping systems and use the data developed during these inspections to monitor the spread of erosion/corrosion in the plants.

Based on the potential low public risk, the NRC need (References 1090, 1094, 1096) to establish a new position or requirement on the previously unexpected phenomena, and a significant industry cost incentive to address and resolve the issue, this issue was classified as a Regulatory Impact issue by RES consistent with the ongoing levels of staff and industry actions described in SECY-88-50[1094] and SECY-88-50A.[1096] However, NRR considered the issue to be resolved based on: (1) guidelines on erosion/corrosion in single-phase piping, as developed by NUMARC and found acceptable by the staff; (2) participation in a timely way by all 113 operating LWR plants; (3) acceptable analytical procedures for the evaluation and selection of piping to be inspected; (4) replacement of components as needed; and (5) a long-term as well as a short-term program for continuing evaluation and inspection of both single-phase and two-phase piping.[1132]

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ISSUE 142: LEAKAGE THROUGH ELECTRICAL ISOLATORS IN INSTRUMENTATION CIRCUITS

DESCRIPTION

Historical Background

Electronic isolators are used to maintain electrical separation between safety and non-safety-related electrical systems in nuclear power plants, preventing malfunctions in the non-safety systems from degrading performance of safety-related circuits. Isolators are primarily used where signals from Class 1E safety-related systems are transmitted to non-Class 1E control or display equipment.

There are a number of devices which may qualify as electrical isolators in a nuclear power plant, including fiber optic and photo-electric couplers, transformer-modulated isolators, current transformers, amplifiers, circuit breakers, and relays. These isolators are designed and tested to prevent the maximum credible fault applied in the transverse mode on the non-Class 1E side of the isolator from degrading the performance of the safety-related circuit (Class 1E side) below an acceptable level.

This issue was identified[1270] by the staff in June 1987 and arose from observations made during SPDS evaluation tests that, for electrical transients below the maximum credible level, a relatively high level of noise could pass through certain types of isolation devices and be transmitted to safety-related circuitry.[1269] In some cases, the amount of energy that can pass through the isolator may be sufficient to damage or seriously degrade the performance of Class 1E components while, in other cases, electrically-generated noise on the circuit may cause the isolation device to give a false output.

Safety Significance

Recent observations have shown instances in which isolation devices subjected to failure voltages and/or currents less than maximum credible fault levels passed significant levels of voltage or current, but the same devices performed acceptably at maximum credible levels. The safety system on the Class 1E side of the isolation device may be affected by the passage of small levels of electrical energy, depending upon the design and function of the safety system.

In the event that safety systems are affected by less than maximum credible faults on the non-Class 1E side of isolators, the effects can range from degradation to failure of single or multiple trains of safety systems resulting in failure on demand or inadvertent operation. In one recorded incident, a voltage transient induced by a power line fault caused a false indication that the turbine-generator output breaker had tripped, resulting in a reactor scram.

Possible Solution

The assumed solution to this issue would require the staff to determine the extent to which potentially susceptible isolators are used in nuclear power plants and to identify the systems in which they are used. An NRC bulletin to all

licensees to provide input on these questions would be necessary. Assuming that the staff determines from the licensee responses to the proposed bulletin that a potential problem exists, a research program consisting of two major objectives would have to be initiated to develop the solution to this issue. The first objective would be to develop test procedures and acceptance criteria for isolators that licensees could use to determine the adequacy of installed isolators. The second objective would involve development of appropriate hardware fixes that could resolve the issue.

Electrical hardware currently exists either to reduce the amount of energy that may leak through electrical barriers provided by various types of isolation devices, or to minimize the consequences of any unwanted signals that may leak through the isolator. Some of these devices are described below.

Surge arresters, also called lightning arresters, provide an effective means of eliminating high voltage transients from a circuit. These devices are simply connected from the conductor directly to ground, preferably as close as possible to the device to be protected. The arresters function by simply shunting to ground any voltage spikes above a certain level.

Filter chokes and capacitors can greatly attenuate high frequency electrical noise. These components create an impedance to the passage of electrical energy proportionate to the frequency of the signal and are especially effective against radio frequency noise. Filter chokes (or reactors) also function as current limiters in AC circuits and thus offer additional protection from overload currents.

At power frequencies, power conditioners can be employed to eliminate all unwanted signals. Power line conditioners function by rectifying an AC signal into DC and then reconverting power through an invertor into a clean, noise-free AC signal. These devices prevent notches, spikes, radio frequency, brownouts, and overload power at the input terminals from degrading the quality of power at the protected output.

The final step in the solution to this issue would be the issuance of a generic letter to licensees with the following guidelines for: (1) inspection and testing of all electrical isolation devices between Class 1E and non-Class 1E systems; (2) repair/replacement of isolators that fail the tests, including description of acceptable hardware fixes to the isolators; and (3) implementation of an annual program to inspect and test all electronic isolators between Class 1E and non-Class 1E systems.

PRIORITY DETERMINATION

Assumptions

A total of 90 PWRs and 44 BWRs are potentially affected by this issue. The expected average remaining lives of these plants are 28.8 and 27.4 years for PWRs and BWRs, respectively.

Frequency Estimate

There are several sources of uncertainty associated with this issue, the most important of which are: (1) the extent to which potentially susceptible isolators

are used at nuclear power plants; (2) the amount of electrical energy leakage through isolation devices that could compromise the function of Class 1E system components; and (3) the number of components in which such compromises would be critical. While a recent study[1269] indicated that a safety problem may exist due to energy leakage through electronic devices, no definitive research has been conducted to date to indicate the character and magnitude of the associated safety concerns. As a result, a sensitivity analysis was performed to bound the potential public risk reduction associated with this issue. Estimates of the upper and lower bounds were developed as well as a third case that represents the "best estimate" based on the available information.

The Oconee 3 and Grand Gulf 1 PRA studies were used as representative of PWRs and BWRs, respectively.[64] The parameters affected by this issue are those involving control circuitry failures and functional failure of ESF actuation systems. These components may be directly affected by energy leakage through isolation devices that are intended to protect them from signals originating in connected non-Class 1E systems. It is also possible that sensors in the Class 1E safety systems may be affected by the electrical energy leakage from the non-Class 1E system. These sensors may include valve position, temperature, and pressure sensors that alert plant operators to take a particular action. In this case, plant operators may be misled into not taking appropriate actions when required. For this reason, operator error terms are also included as potentially affected parameters. The affected parameters in the Oconee 3 and Grand Gulf 1 PRAs were identified and modified to model the three sensitivity cases.

Best Estimate: All of the affected control circuitry failure, ESF actuation functional failure, and operator error terms were multiplied by a factor of two (assumed) to account for the potential additional failures associated with electrical isolators. A factor of two was assumed based on engineering judgment and the findings of previous prioritization analyses.

Upper Bound: All of the affected control circuitry failure, ESF actuation functional failure, and operator error terms were multiplied by a factor of ten (assumed) to account for the potential additional failures associated with electrical isolators. A factor of 10 was likewise assumed based on judgment and previous analytical experience.

Lower Bound: The control circuitry and ESF actuation functional failures were multiplied by a factor of 1.4. This is based on an assumed factor of two increase in only the probability of fuse failures which are included in the control circuitry unavailability values. No effect on the operator error terms were assumed in this case.

It is noted that varying all the control circuitry, ESF function failure, and operator error terms is a conservative approach. Logic dictates that not all the terms would be affected at the same time and that a plant-specific detailed evaluation would probably result in a reduced sensitivity. After the failure terms were modified, they were combined with the remaining unaffected portions of the parameter unavailabilities to calculate the revised unavailabilities. The affected cut-set elements and their base case and adjusted case unavailability values are shown in Table 3.142-1.

TABLE 3.142-1
Base Case and Adjusted Case Values of Affected Parameters

Parameter	Adjusted Case[a]	Base b Case 1[a]	Base Case 2[c]	Base Case 3[d]
Grand Gulf				
H	0.0212	0.0225	0.0217	0.0329
HACT,RACT	0.00123	0.00223	0.00163	0.0102
R	0.0512	0.0530	0.0518	0.067
L	0.0213	0.0226	0.0218	0.033
LRACT,BCACT	0.00123	0.00223	0.00163	0.0102
LA2,LB2	0.0140	0.0151	0.0144	0.0240
LB1	0.0134	0.0138	0.0135	0.017
LC	0.0215	0.0230	0.0220	0.035
VGA1,VGB1	0.0148	0.0156	0.0150	0.022
VGA2,VGB2	0.0236	0.0273	0.0238	0.0553
SA,SB	0.0144	0.0150	0.0146	0.0198
SAACC, SBACC	0.00123	0.00223	0.00163	0.0102
SSA,SSB	0.0205	0.0223	0.0209	0.0361
SSC	0.0140	0.0151	0.0144	0.0239
SAC,SBC,SCC	0.00123	0.00223	0.00163	0.0102
V1, V2	0.00803	0.0091	0.00813	0.0173
V3	0.0033	0.0064	0.0033	0.0296
SCVA,SCVB	0.0315	0.0333	0.0321	0.0477
Oconee				
B,C	0.0033	0.0043	0.0037	0.0121
D,E	0.0231	0.0354	0.0249	0.1334
CONST1	0.0002	0.00048	0.0003	0.0007
CONST2	0.0006	0.00125	0.00083	0.0123
A1,C1	0.0098	0.0163	0.0124	0.0683
B1	0.0349	0.0502	0.0710	0.1718
G1	0.0136	0.0172	0.0150	0.046
RCSRBCM	0.00003	0.00007	0.00003	0.00032
WXCM	0.003	0.006	0.003	0.03
D.E	0.00049	0.00121	0.0006	0.0178
W.X	0.00009	0.00025	0.0001	0.00451
B.W, C.X	0.00003	0.00006	0.00004	0.00081
D.X, E.W	0.00021	0.0006	0.00029	0.00895
B.D, E.C	0.00006	0.0001	0.00008	0.0016

NOTES:
a - Original Oconee 3 and Grand Gulf 1 PRA values
b - Best estimate
c - Lower bound case
d - Upper bound case

In performing the risk analysis, it was assumed that the isolator failures were not considered as potential causes of failure in the original Oconee and Grand Gulf PRAs. (This assumption may also introduce additional conservatism.)

Since the base case was intended to represent the situation in which isolator failures are considered as possible causes of safety system failures and the adjusted case represented the situation after the resolution is implemented, the modified parameter values were used in the base case and the adjusted case represent the original Oconee and Grand Gulf parameter values. The base case and adjusted case values of the affected parameters were then incorporated in the Oconee 3 and Grand Gulf 1 PRAs to derive the estimated core-melt frequency and the associated public risk reduction. Based on the data in Table 3.142-1, the following core-melt frequency reduction was estimated for the representative PWR and BWR.

Sensitivity Case	Core-Melt Frequency Reduction PWR	BWR
Best Estimate	2.59×10^{-5}/RY	7.98×10^{-6}/RY
Lower Bound	5.37×10^{-6}/RY	2.07×10^{-6}/RY
Upper Bound	4.35×10^{-4}/RY	1.17×10^{-4}/RY

Utilizing generic release categories and containment failure modes, the public risk reduction was estimated to be as follows:

Sensitivity Case	Public Risk Reduction (man-rem/RY) PWR	BWR
Best Estimate	57	53
Lower Bound	13	14
Upper Bound	1,016	789

Based on the public risk reduction estimates presented before for the representative PWR and BWR and the three sensitivity cases, the following public risk reduction was estimated (weighted average over all affected PWRs and BWRs and their remaining lives):

Best Estimate = 1,580 man-rem/plant
Lower Bound = 378 man-rem/plant
Upper Bound = 26,752 man-rem/plant

Cost Estimate

Industry Cost: It was assumed that the proposed generic letter would contain the following guidelines applicable to all affected plants: (1) inspection and testing of all electrical isolation devices between Class 1E and non-Class 1E systems; (2) replacement of failed or unacceptable isolators, including descriptions of acceptable hardware fixes to the isolators; and (3) implementation of an annual program to inspect and test all electronic isolators between Class 1E and non-Class 1E systems.

The initial testing and inspection program at each plant was estimated to require approximately 4 man-weeks for planning and 8 man-weeks for review and evaluation of the data, preparation of the final response to the generic letter, and

preparation of a safety analysis. The cost to conduct the initial test program was highly uncertain because there were unknown numbers of affected systems and susceptible isolators at each plant. For this analysis, the number of potentially affected isolators was estimated using the number of safety system components in the Oconee and Grand Gulf PRAs with functional and/or control circuitry failure terms. Accordingly, 46 isolators for BWRs and 78 isolators for PWRs were estimated. Assuming a two-man team can test 10 isolators per day, labor requirements for the initial test/inspection required by the generic letter were estimated at 10 man-days/plant for PWRs and 16 man-days/plant for BWRs.

Furthermore, isolators that fail the initial tests must be replaced or repaired. It was conservatively assumed that 25% of the tested isolators will fail the tests; this would result in 12 failures at PWRs and 20 failures at BWRs. The cost to purchase, install, test, and perform adequate QC of acceptable replacement isolators was estimated at $10,000/isolator and this included approximately 2 man-days/isolator for replacement. Thus, the total isolator replacement costs were estimated to be $120,000/plant and $200,000/plant for PWRs and BWRs, respectively. Assuming a cost of $2,270/man-week, the total implementation cost (including hardware) was estimated to be $156,000/plant and $239,00/plant for PWRs and BWRs, respectively.

The generic letter was assumed to include a requirement for annual testing and inspection of all electronic isolators. The industry labor requirements for this activity were estimated to be 1 man-week/RY for test planning (this was significantly lower than the 4 man-weeks for planning the initial test program), plus 10 man-days/RY to conduct the tests at PWRs and 16 man-days/RY to conduct the tests at BWRs. An additional 1 man-week/RY at all plants to review the test results and prepare a report for the NRC was also included. This resulted in estimated labor requirements of 4 man-weeks/RY and 5.2 man-weeks/RY for PWRs and BWRs, respectively.

Furthermore, the annual testing program was likely to determine that there were additional failed or suspect isolators that required replacement. It was assumed that all the remaining isolators (i.e., other than those that were replaced as a result of the initial test program) will eventually be replaced with acceptable components. The number of remaining isolators to be replaced at PWRs was estimated to be 38 (i.e., 46 - 12) over a 28.8 year period or 1.2/RY. At BWRs, the annual replacement rate was 58 (i.e., 78 - 20) over a 27.4 year period, or 2.1/RY. The annual replacement costs at each plant were thus estimated to be $12,000/RY and $21,000/RY for PWRs and BWRs, respectively.

At $2,270/man-week, the total cost of maintenance and operation (including hardware) of the possible solution at each plant was estimated to be $21,000/RY and $33,000/RY for PWRs and BWRs, respectively. Using a 5% discount rate, the present worth cost associated with plant maintenance and operation for PWRs and BWRs was estimated to be $11,600/RY and $18,300/RY, respectively.

NRC Cost: It was assumed that the first activity would involve issuance of a bulletin to determine the extent to which potentially susceptible isolators were used in nuclear power plants and to identify the systems in which they were used. It was estimated that 2 man-weeks ($4,000) would be required to prepare the bulletin. To perform the review and analysis of licensee responses to the bulletin, it was estimated that 6 man-months ($50,000) of technical support would be needed at a cost of $54,000.

Assuming that, after analyzing licensee responses, the staff concluded that the issue warranted further attention, the second activity would involve a research program that would develop the details of the final resolution to this issue. This program would involve two major objectives. First, test procedures and acceptance criteria for isolators would be developed for licensee use in determining the adequacy of their installed isolators. It was estimated that a $50,000 contract plus $10,000 for NRC contract support would be needed to accomplish this objective. Second, appropriate hardware fixes would be developed that could resolve the issue. Safety and cost analyses to determine the cost-effectiveness of the proposed hardware fixes would also be necessary. An estimated $150,000 contract plus $20,000 for NRC contract support would be needed to accomplish this activity. Thus, the total cost of this activity was estimated to be $230,000.

The next step was to prepare and issue a generic letter to all licensees. Approximately 4 man-weeks ($10,000) were estimated to prepare and issue the letter. It was estimated that 6 man-months of staff time would be required to review and evaluate each licensee response. (This was equivalent to a $55,000 contract and $10,000 for NRC contract support.) Thus, the total estimated cost for this effort was $75,000.

Based on the above estimates, the total NRC cost for development of the possible solution was $355,000. Averaging this cost over the 134 affected plants resulted in a cost of $2,650/plant for development.

It was assumed that the staff would review the implementation of the requirements in the generic letter, review the test procedures, review plant-specific implementation plans, and prepare a safety evaluation. The cost for this review was estimated to be 4 man-weeks/plant. At $2,270/man-week, this cost was $9,080/plant.

An additional 0.5 man-week/RY of NRC effort would be required for an annual review of the operation and maintenance of the solution. Summing this cost over the remaining lives of the affected plants at $2,270/man-week resulted in a cost of $32,200/plant. Using a 5% discount rate, the present worth of this review was $17,900/plant.

Therefore, the total NRC cost for the development and implementation of the possible solution was estimated to be approximately $30,000/plant.

Total Cost: The total industry and NRC cost for implementation of the proposed solution was estimated to be $0.6M/plant.

Value/Impact Assessment

Based on the above estimates, the following value/impact scores were calculated for the three cases considered.

Best Estimate:

$$S = \frac{1{,}580 \text{ man-rem/plant}}{\$0.6\text{M/plant}}$$

$$= 2{,}633 \text{ man-rem/\$M}$$

Lower Bound: $S = \frac{378 \text{ man-rem/plant}}{\$0.6\text{M/plant}}$

$= 630$ man-rem/$M

Upper Bound: $S = \frac{26{,}752 \text{ man-rem/plant}}{\$0.6\text{M/plant}}$

$= 44{,}587$ man-rem/$M

Other Considerations

(1) Implementation of the possible solution was assumed to include repair, replacement, and testing of potentially susceptible isolators. This resulted in labor estimates of 34 man-days/plant for PWRs and 56 man-days/plant for BWRs in radiation zones. Radiation fields of 25 millirem/hr were assumed to exist inside containment where most of the isolators were located. Utilizing a 75% efficiency factor for labor in radiation zones, the occupational dose increase for implementation of the possible solution was estimated to be 9.1 man-rem/plant and 14.9 man-rem/plant for PWRs and BWRs, respectively.

(2) Licensee labor requirements in radiation zones for operation and maintenance of the possible solution included:

	PWRs (man-days/RY)	BWRs (man-days/RY)
Annual Test Program	10	16
Replacement of Isolators	2.4	4.2
Total:	12.4	20.2

Again, utilizing a 75% efficiency factor for labor in radiation zones and radiation fields of 25 millirem/hr resulted in an estimated increase in ORE of 3.3 man-rem/RY and 5.4 man-rem/RY for PWRs and BWRs, respectively. Summing these values over the remaining lives of the affected plants (28.8 years for PWRs and 27.4 years for BWRs) resulted in an increase in ORE of approximately 95 man-rem/plant and 148 man-rem/plant for PWRs and BWRs, respectively.

CONCLUSION

The best estimate of public risk reduction associated with preventing leakage through electrical isolators was significant and indicated a high priority ranking. However, the calculation of risk reduction included a number of conservative assumptions. Generally, use of conservative assumptions where real data does not exist will always result in overprediction of potential risk reduction. In acknowledgement of the conservatism in the analysis, a medium priority ranking was assigned to the issue (See Appendix C). This ranking was consistent with the qualitative judgments of the staff and was further supported by NRR's stated intention to process a research request to initiate an electrical isolator testing program to improve the current state of knowledge concerning

isolator characteristics at less than maximum credible fault levels. The resolution of the issue was expected to address the safety concern of Issue 156.4.1.

In resolving the issue, the staff determined from operating experience that isolation devices perform satisfactorily in the operating environment and have not been exposed to failure mechanisms that resulted in signal leakage. This determination was based in part on plants that predominantly use electromechanical controls and may not be applicable to control systems with digital or electronic components. Therefore, RES recommended the development of an SRP[11] Section to provide review guidance for future plants that use digital systems, and for OLs that convert safety-related systems from analog to digital; the regulatory analysis was published in NUREG-1453.[1593] Thus, this issue was resolved and no new requirements were established.[1511] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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ISSUE 143: AVAILABILITY OF CHILLED WATER SYSTEMS AND ROOM COOLING

DESCRIPTION

Historical Background

In past years, several nuclear plants experienced problems with safety system components and control systems that resulted from a partial or total loss of HVAC systems. Many of these problems occurred for two reasons: (1) the desire to provide increased fire protection; and (2) the need to avoid severe temperature changes in equipment control circuits. Since the Browns Ferry fire, considerable effort had been expended to improve the fire protection of equipment required for safe shutdown. Generally, this improvement had been accomplished by enclosing the affected equipment in small, isolated rooms. However, the result was a significant increase in the impact of the loss of room cooling. Another problem resulting from loss of room cooling was the technological advances in control circuit design. With the introduction of electronic integrated circuits, plant control and safety improved; however, these circuits were more susceptible to damage from severe changes in temperature caused by the loss of room cooling.

It was believed that failures of air cooling systems for areas housing key components, such as RHR pumps, switchgear, and diesel generators, could contribute significantly to core-melt probability in certain plants. Because corrective measures are often taken at the affected plants once these failures occur, the ACRS believed that the impact of these failures on the proper functioning of air cooling systems had not been reflected in the final PRAs of plants. Thus, plants with similar, inherent deficiencies may not have been aware of these problems.[1317]

Safety Significance

Operability of some safety-related components is dependent upon operation of HVAC and chilled water systems to remove heat from the rooms containing the components. If chilled water and HVAC systems are unavailable to remove heat, the ability of the safety equipment within the rooms to operate as intended cannot be assured.

Possible Solution

A possible solution to this issue would require a reevaluation of each plant's room heat load and heat-up rate in order to identify areas in which a reduction in the dependence of equipment operability on HVAC and room cooling may be implemented. While the total elimination of this dependence may not be possible at all plants, this reevaluation would identify areas in which this dependence was critical. The determination of the critical dependencies and the ability to reduce them could be accomplished through the use of a plant-specific PRA such as an IPE. After the critical dependencies were identified, each plant would implement procedural changes (to provide alternate cooling) to eliminate or reduce the dependencies where possible. Hardware modifications may be needed for situations in which a procedure change cannot be implemented to reduce a critical dependency.

The next step in the possible solution would be the issuance of a generic letter that would require licensees to: (1) evaluate the dependencies of plant safety systems and equipment operability on HVAC and room cooling; (2) identify areas in which this dependence was critical; (3) identify appropriate procedure changes and hardware modifications to minimize the effects of the dependencies on plant risk; (4) submit this evaluation to the NRC for review and approval of the proposed modifications; and (5) implement the approved procedural changes and hardware modifications. The generic letter would include guidance on acceptable procedures licensees could use to evaluate the potential dependencies in the design of these systems. The generic letter would also include alternative solutions for improving the independence of systems that are critical to plant risk. It was assumed that a research project would form the basis for a more fully-developed solution and for the guidance in the generic letter.

PRIORITY DETERMINATION

Assumptions

The Grand Gulf Unit 1 and Oconee 3 PRAs were used as representative of BWRs and PWRs, respectively. A total of 90 PWRs and 44 BWRs were potentially affected by this issue and were expected to continue operating for an average of 28.8 and 27.4 years, respectively.[64] For comparative purposes, 71 operating plants were assumed: 47 PWRs and 24 BWRs.

Frequency Estimate

Several systems at Grand Gulf 1 were affected by HVAC or room cooling failures in locations that included: (1) emergency switchgear and battery rooms; (2) standby diesel generator rooms; and (3) pump rooms for RHR, RCIC, high pressure cooling system (HPCS), and low pressure cooling system (LPCS). A loss of cooling was assumed to fail the following: (1) operating diesel generators in 15 minutes; (2) battery, emergency switchgear, and low pressure ECCS (i.e., RHR and LPCS) pumps in 4 hours; and (3) HPCS and RCIC in 12 hours. An examination of the Grand Gulf 1 emergency ventilating system fault trees provided a list of basic events that result in failure of systems due to HVAC failure.[64]

Next, the core-melt sequences for the dominant core damage categories were examined. When a sequence was found that contained one of the above-mentioned basic events, it was reviewed to determine the effect of eliminating the dependence on HVAC/room cooling. Three effects were possible. First, the sequence could no longer result in core damage. These scenarios were eliminated, resulting in a direct reduction in CDF. Second, the HVAC/room cooling basic event was replaced with another basic event (e.g., replacing diesel generator room cooling failure with a diesel generator hardware failure). The new sequence was compared with the other sequences in the dominant sequence mode and, if an identical sequence was found, the new sequence was absorbed, resulting in a CDF reduction by the amount of the frequency of the absorbed cutset. The third effect was similar to the second except that no other sequence was found to be identical. In this case, this same new sequence was substituted for the original and a new sequence frequency was calculated. The contribution to changing the core-melt frequency was the difference between the original and the new frequency.

The evaluation was performed assuming that all dependence on HVAC and room cooling could be eliminated. The elimination of this dependence was expected to

be accomplished by a reevaluation of room heat capacity and heat-up, by the implementation of procedures that provide alternate cooling, or by the implementation of hardware modifications that would eliminate the dependence. The result of the evaluation was a CDF reduction of 8×10^{-6} event/RY at Grand Gulf 1. It should be noted that this reduction was a maximum using the above assumptions and might not have been achievable in all plants. However, every nuclear plant should realize some reduction in the probability of core damage.

The HVAC systems at Oconee 3 consisted of various flow-through systems as well as individual room coolers. Two flow-through systems, one for the control room and one for the auxiliary building, and the room coolers for the low pressure injection (LPI) and reactor building spray system (RBSS) were examined in detail. The PRA determined that only the room coolers for LPI and RBSS had a potential contribution to core damage; this contribution was examined below. The unavailability values were obtained from Appendix A of NSAC-60.[889]

Room Cooler Failure = (Fan 1)(Operator + Fan 2)
$= (1.9 \times 10^{-4})[10^{-3} + (1.9 \times 10^{-4})]$
$= 2.4 \times 10^{-7}$

LPI Pump Fails (Start and Run) $= 1.3 \times 10^{-3}$
Room Cooler Contribution = 0.02%

RBSS Pump Fails (Start and Run) $= 8.3 \times 10^{-3}$
Room Cooler Contribution = 0.003%

As a final part of the evaluation, an examination of the leading core damage sequences from internal events was made. Failures of the LPI and RBSS pumps were not contributors to any of these sequences.

A second potential contribution from HVAC or room cooling was through the loss of service water which is the heat sink. Service water, however, also provides direct cooling of the high pressure injection (HPI) pumps. An examination of the event trees for Oconee 3 shows that core damage mitigation using the low pressure systems could only be accomplished if HPI was successful first. Therefore, a failure of service water would result in a loss of HPI and core damage and no contribution from loss of room cooling would be found.

Based on the preceding discussion, it was concluded that no further analysis using NSAC-60[889] would be performed because of a lack of dependency on HVAC and room cooling. Therefore, to model the effects of the solution on a generic PWR, the scaling technique described in NUREG/CR-2800[64] was used. In this technique, it was assumed that the core-melt frequency for a BWR was 0.45 times that for a PWR. In addition, it was assumed that the public risk for a BWR plant was approximately 1.2 times that for a PWR plant. This resulted in a core-melt frequency reduction estimate of 1.8×10^{-5}/RY.

Consequence Estimate

The reduction in core-melt frequency for BWRs was translated into a reduction in public risk of about 57 man-rem/RY.[64] For the 44 BWRs, this amounted to a risk reduction of 6.9×10^{4} man-rem. The public risk reduction for PWRs was calculated to be 47 man-rem/RY.[64] For 90 PWRs, this amounted to a risk reduction of 1.2×10^{5} man-rem.

Cost Estimate

Industry Cost: The proposed solution called for licensees to evaluate the dependencies of HVAC and chilled water systems on room cooling systems and the subsequent effects on plant risk. This engineering analysis was assumed to require approximately 1 man-year of effort ($100,000/plant) and would include the identification and evaluation of dependencies as well as identification of appropriate procedure changes and hardware modifications to minimize the effects of the dependencies on plant risk. Licensees would submit their evaluations to the NRC for review.

The next step would be for licensees to implement the proposed procedural changes and hardware modifications at their plants. Procedural changes would be proposed where possible because of the expense and occupational doses associated with implementing hardware modifications in radiation areas. However, it was believed that procedural changes would not resolve the dependencies in some cases, particularly where failure of room cooling was a critical failure mode for an important safety-related component. In these cases, it may be necessary to replace a particular piece of equipment with one that can be operated independently of HVAC and chilled water systems. Alternatively, a component of the HVAC or chilled water system, such as one or more of the room coolers, may be replaced with one of a different design that can be operated independently of the HVAC or chilled water systems.

The cost estimates for the procedural changes and hardware modifications were taken from NUREG/CR-4627.[961] It was assumed that each plant would implement 2 procedural changes and replace 8 room coolers. The procedural changes were anticipated to be relatively complex and, therefore, would require approximately $3,600/change or $7,200/plant. The proposed solution was somewhat similar to the removal and replacement of the containment spray heat exchangers because work would be performed in a radiation environment and in a relatively congested area.[961] It was also stated in NUREG/CR-4627[961] that these cost estimates should be applied only to plants that were operating or at the 70% or higher completion state of construction. The removal and replacement cost was therefore applied only to the assumed 71 operating plants. The proposed resolution was assumed to result in no incremental costs for plants that were under construction. The removal and replacement costs were summarized as follows for each operating plant:

(1) Purchase Cost (8 Room Coolers)	= $ 968,000
(2) Labor Cost (12,400 man-hrs @ $21.74/hr times labor productivity adjustment, removal, engineering, and QA factors)	= 356,000
TOTAL:	1,324,000

Therefore, the industry cost for implementation was estimated to be $100,000/plant for the engineering study, $1.324M/operating plant for the hardware upgrade, and $7,200/plant for the procedure changes. These upgrades and changes were anticipated to be one-time activities. No additional resources were expected for operation and maintenance of the upgraded equipment. Thus, the total industry cost for all affected plants was approximately $108.4M.

NRC Cost: The first step in the proposed solution would involve issuance of a generic letter to all licensees to evaluate the dependencies on adequate room cooling of the operation of HVAC and chilled water systems. Issuance of the generic letter was assumed to cost approximately the same as a simple TS change, as described in NUREG/CR-4550,[1318] including the necessary reviews and approvals; this cost was $13,000. The generic letter would include a description of the proposed resolution and guidance on acceptable procedures for licensees to use to evaluate the potential dependencies in the design of these systems and alternative solutions to improving the independence of systems that are critical to plant risk. It was assumed that a research project would form the basis for a more fully-developed solution and for the guidance in the generic letter. This research project was assumed to be performed by a contractor and was estimated to require 6 man-months at a cost of $50,000.

Review and approval of the proposed modifications were estimated to require approximately 1 man-week/plant or $2,270/plant. No incremental resources were foreseen for review of the operation and maintenance of the upgraded equipment. Thus, the total estimated NRC cost for all plants was approximately $370,000.

Total Cost: The total industry and NRC cost for implementing the possible solution was estimated to be $(108.4 + 0.37)M or approximately $109M for the 71 affected plants.

Value/Impact Assessment

Based on an estimated public risk reduction of 1.9×10^5 man-rem and a cost of $109M for the possible solution, the value/impact score was given by:

$$S = \frac{1.9 \times 10^5 \text{ man-rem}}{\$109M}$$

$$= 1.7 \times 10^3 \text{ man-rem/\$M}$$

Other Considerations

(1) The analysis for estimating core-melt frequency reduction was performed for BWRs and scaled for PWRs using the scaling relationships given in NUREG/CR-2800.[64] This assumption may have introduced considerable additional uncertainty to the estimated core-melt frequency reduction for PWRs. Nevertheless, the contribution due to BWRs alone approached the high priority threshold value, even if the contribution from PWRs were smaller.

(2) Labor for removal and replacement of 8 heat exchangers within containment was estimated in NUREG/CR-4627[961] to be approximately 4,000 man-hours. A productivity factor of 3.1 was used to adjust the labor estimate to account for inefficiencies caused by work in radiation zones, congested areas, and difficult access areas. The total labor in radiation zones was estimated to be 12,400 man-hours/operating plant. Assuming a radiation field of 25 millirem/hour inside containment where the room coolers are located, implementation of the possible solution was estimated to result in an ORE increase of 310 man-rem/plant.

CONCLUSION

Because the estimated risk reduction from eliminating (or decreasing) the dependence of safety systems on HVAC and room cooling could be quite significant, the issue was given a high priority ranking (See Appendix C). In resolving the issue, the staff found that, although there might be some plant-specific accident sequences involving loss of HVAC/room cooling that could contribute significantly to core damage, any vulnerabilities that might exist were expected to be identified by licensees as part of the IPE process; a study of the issue was published in NUREG/CR-6084.[1550] The staff's regulatory analysis was documented in NUREG-1427[1549] and the issue was RESOLVED with no new requirements.[1551] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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ISSUE 144: SCRAM WITHOUT A TURBINE/GENERATOR TRIP

DESCRIPTION

Historical Background

Prior to 1989, there were several reported occurrences of the failure of turbine/generators to trip after a reactor scram. These events were caused either by mechanical or electrical problems in the turbine electro-hydraulic control system. In particular, one occurrence at Crystal River Unit 3 was caused by both a defective solenoid spring in the turbine trip circuitry and corrosion in a fuse holder, which produced a reduced DC voltage to the solenoid (LER 88-006). However, in this instance, the turbine also could not be tripped manually. Therefore, the turbine/generator breakers were opened, thereby tripping the turbine on overspeed 14 seconds after the reactor scram. Because of the reported occurrences, the staff recommended that a scram without a turbine/generator trip (SWATT) be evaluated as a new issue to address the potential for a SWATT and its associated effects.[1378]

One of the possible effects of a SWATT is the overcooling of the primary system which can cause recriticality, pressurized thermal shock (PTS), or both. PTS, which is caused by an overcooling transient followed by or concurrent with high reactor vessel pressure, was previously addressed in Issue A-49. This led to the PTS rule which established new requirements for all PWRs.

Besides possibly causing vessel failure from PTS, an overcooling transient can induce recriticality in the reactor. Recriticality may be caused by an overcooling transient that occurs towards core end-of-life when the boron concentration is low, and thus the moderator temperature reactivity coefficient is most negative. With a rare combination of operating conditions, this could produce a pressure spike in the primary system and lead to the same conditions of a PTS event.

Another possible effect of a SWATT is overspeed of the turbine which can cause turbine missiles and damage the integrity of the onsite power distribution systems by large fluctuations in generator voltage and frequency. Turbine missiles were addressed in Issue A-37 which was determined to have little safety significance. Because of its close relationship with Issue A-37, this issue was used to reexamine the analysis of Issue A-37.

Safety Significance

A SWATT is significant to the safety for LWRs because the possible effects from this event can lead to a core-melt. These effects include the following: (1) recriticality and PTS, due to a primary system overcooling event; (2) turbine missiles, from overspeed of the turbine; and (3) loss of core cooling and inventory makeup, due to other events caused by the SWATT, such as SGTRs. In addition, plants without MSIVs do not have the capability to quickly stop the supply of steam to the turbine. MSIVs provide increased protection from the consequences of a SWATT and, thus, plants without them are potentially more vulnerable.

Possible Solutions

The possible solution involves three activities designed to improve the reliability that a turbine/generator trip occurs following a reactor trip: (1) installation of redundant and diverse emergency trip systems; (2) improved periodic inspection, testing and maintenance of turbine/generator trip systems; and (3) clarification of operating procedures and training for operating personnel.

PRIORITY DETERMINATION

Assumptions

It was assumed that 71 operating plants would be affected by this issue: 47 PWRs and 24 BWRs with average remaining lives of 27.7 and 25.2 years, respectively. Of these 71 plants, only the three PWRs at Oconee with average remaining lives of 26, 27, and 27 years do not have MSIVs.

Frequency Estimate

The core-melt frequency from a SWATT is related to the failure to isolate the steam supply to the turbine. Isolation of the turbine helps to either prevent or mitigate the consequences of the following: (1) primary system overcooling, which could directly cause core damage through either PTS or recriticality; (2) turbine overspeed, which could indirectly cause core damage through turbine missiles and electrical power fluctuations; and (3) SGTRs, which could directly cause core damage through the effects of a small break LOCA at the steam generator. The events that lead to these consequences and their associated failure probabilities are described below.

The initiating event for the SWATT is a reactor transient, which causes the reactor to trip. The event that leads to this issue, however, is the subsequent turbine trip failure. Using data from the 1990 AEOD Report (NUREG-1272,[1472] Vol.5, No. 1), the average frequency of a reactor trip from 1986 to 1990 was calculated to be 2.8/RY and 2.5/RY for PWRs and BWRs, respectively. The probability of turbine trip failure, given a reactor trip and including contributions from operator error and equipment failure, was estimated[1376] to be 1.7×10^{-3} per demand.

Possible responses[1377] to a SWATT are as follows: (1) the generator can be tripped, which causes the turbine to trip on an overspeed condition; (2) the turbine can be isolated by closing the MSIVs in those plants that have them; and (3) the turbine can be locally tripped by manual operator action. Each of these responses has failure probabilities due to equipment faults and operator actions. Because of insufficient data, the following conservative assumptions were made:

(1) All equipment faults were assigned a failure probability of 0.05/demand;

(2) The failure probability for an operator to perform a corrective manual action for both the generator trip and the MSIV closure was assigned a value of 0.03/demand;

(3) The failure probability for locally tripping the turbine was assigned a value of 0.1/demand, because this trip is located in the turbine building.

The resulting conditional probabilities for failure to isolate the steam supply to the turbine were calculated by summing each plant state resulting in a non-isolable condition.[1378] The resulting event sequences for turbine trip failure, feedwater availability, and core cooling and inventory makeup were then used to investigate the possible effects of a SWATT. These effects include PTS, turbine missiles, and SGTRs. The effects of a SWATT for those reactors without MSIVs (the three units at Oconee) were investigated using the same models by assuming the failure probability for MSIV closure is equal to 1.

An important assumption regarding the previous calculation of the core-melt frequency from PTS was that a SWATT is functionally similar to a large steam line break (LSLB) occurring downstream of the MSIVs. A study[1376] by INEL showed that, for B&W reactors, a graph of the reactor vessel downcomer temperature as a function of time for the failed turbine trip scenario was very close to that calculated for a LSLB in developing the PTS rule. The same conclusion would be expected for other reactor types. Therefore, the probability of reactor vessel failure due to a SWATT was estimated to be equal to that calculated for a LSLB. Even if it were assumed that this probability was an order of magnitude higher for a SWATT than for the most limiting steam line break (which is not the largest size break), the core-melt frequencies would still be extremely low.

In addition, to simplify the analysis, recriticality events were neglected from further study because these events were not likely to generate a pressure pulse significant enough to cause reactor vessel failure.[1379] In support of this conclusion, others have estimated that the heat addition to the primary coolant system after a recriticality would occur gradually, thus reducing the risk of PTS.[1376]

The base case core-melt frequencies for PTS, turbine missiles, and SGTRs are summarized as follows:

PWRs:	Event	With MSIVs	Without MSIVs
	PTS	8.8×10^{-12}/RY	2.9×10^{-10}/RY
	Turbine Missiles	1.1×10^{-9}/RY	3.5×10^{-8}/RY
	SGTR	1.4×10^{-8}/RY	4.5×10^{-7}/RY
	Total:	1.5×10^{-8}/RY	4.9×10^{-7}/RY

BWRs:	Event	With MSIVs
	PTS	8.1×10^{-12}/RY
	Turbine Missiles	9.4×10^{-10}/RY
	Total:	9.4×10^{-10}/RY

The effect of the possible solution would be to improve the reliability that the turbine will trip on demand after a reactor trip. The solution is also expected to result in reductions in the probabilities of other events in the turbine trip

failure event tree, because of enhanced training and awareness of operators to respond to a SWATT. To reflect the above, it was assumed that the solution will reduce the probability of a failure of the turbine to trip to one-half the base case value. In addition, human error probabilities were assumed to be reduced by 50% as a result of enhanced training and operator awareness. These values were substituted into the turbine trip event tree to calculate revised turbine trip failure frequencies and turbine overspeed trip failure frequencies. No changes were made to the feedwater and core cooling/makeup event trees. The adjusted case turbine and overspeed trip failure frequencies were then substituted into the calculations described previously to calculate the adjusted case core-melt frequencies. These are summarized as follows:

PWRs:	Event	With MSIVs	Without MSIVs
	PTS	2.0×10^{-12}/RY	1.4×10^{-10}/RY
	Turbine Missiles	2.7×10^{-10}/RY	1.8×10^{-8}/RY
	SGTR	3.2×10^{-9}/RY	2.2×10^{-7}/RY
	Total:	3.5×10^{-9}/RY	2.4×10^{-7}/RY

BWRs:	Event	With MSIVs
	PTS	1.9×10^{-12}/RY
	Turbine Missiles	2.4×10^{-10}/RY
	Total:	2.4×10^{-10}/RY

From the base case and adjusted case calculations above, the core-melt frequency reduction was estimated to be 1.2×10^{-8}/RY, 2.5×10^{-7}/RY, and 7×10^{-10}/RY for PWRs with MSIVs, PWRs without MSIVs, and BWRs, respectively.

Consequence Estimate

The next step in this analysis combined the accident sequence frequencies with their corresponding containment failure probabilities. These probabilities were taken from NUREG/CR-2800[64] for similar accident sequences, where possible. Thus, it was observed that the SGTR sequence is similar to sequence S_3H in the Oconee 3 PRA. It was more difficult to match sequences involving PTS and turbine missiles with those for Oconee 3 and Grand Gulf 1. Therefore, a conservative approach was taken that incorporated the most damaging (and highest offsite doses) containment failure modes. The most damaging containment failure mode sequence for Oconee 3 is S_3H; the most damaging containment failure mode sequence for Grand Gulf 1 is $T_{23}PQE$.

The base case and adjusted case affected public risk was determined by combining the accident sequence frequencies, containment failure probabilities, and dose consequences for the release categories corresponding to the appropriate containment failure modes. The dose consequence estimates developed by PNL[64] for each release category were used in this analysis. The following is a summary of the potential risk reduction:

PWRs With MSIVs:	3.2×10^{-2} man-rem/RY
PWRs Without MSIVs:	6.5×10^{-1} man-rem/RY
BWRs:	2.0×10^{-3}/RY

For the 68 affected plants with MSIVs, the total public risk reduction is $[(44)(27.7(3.2 \times 10^{-2}) + (24)(25.2)(2 \times 10^{-3})]$ man-rem or 40 man-rem. For the 3 affected plants without MSIVs, the potential risk reduction is $[(26 + 27 + 27)(6.5 \times 10^{-1})]$ man-rem or 52 man-rem.

Cost Estimate

Industry Cost: The total industry cost was estimated to be $24M and included $16M for implementation of the possible solution and $7.8M for operation and maintenance. For those plants without MSIVs, the total cost was estimated to be $1.2M.[1377]

NRC Cost: Development and implementation of the solution were estimated to cost $55,000 and $810,000, respectively. Review of operation and maintenance was estimated to cost another $2.6M. Thus, the total cost was estimated to be $3.5M.

Total Cost: For plants with MSIVs, the total cost associated with the possible solution is $(24 + 3.5)M or $27.5M. For plants without MSIVs, the estimated cost was $1.2M.

Value/Impact Assessment

(1) With MSIVs: Based on a public risk reduction of 40 man-rem and a cost of $27.5M, the value/impact score was given by:

$$S = \frac{40 \text{ man-rem}}{\$27.5M}$$

$$= 1.5 \text{ man-rem/\$M}$$

(2) Without MSIVs: Based on a public risk reduction of 52 man-rem and a cost of $1.2M, the value/impact score was given by:

$$S = \frac{52 \text{ man-rem}}{\$1.2M}$$

$$= 43 \text{ man-rem/\$M}$$

CONCLUSION

This issue had a greater impact on plants without MSIVs than those with MSIVs. In either case, the potential risk reduction was small and the issue was given a LOW priority ranking (See Appendix C). In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1376. Letter to D. Solberg (NRC) from T. Charlton (INEL), "Transmittal of Letter Report on Turbine Trip Failure Events - TRC-28-88," April 27, 1988.

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1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 145: ACTIONS TO REDUCE COMMON CAUSE FAILURES

DESCRIPTION

Historical Background

This issue was identified as an alternative approach to the Finding 15 recommendation[886] discussed in Issue 125.I.5, "Safety Systems Tested in All Conditions Required by DBA," which states that "[t]horough integrated system testing under various system configurations and plant conditions as near as practical to those for which the system is required to function during an accident is essential for timely detection and correction of common mode design deficiencies." In Issue 125.I.5, it was proposed that integrated systems and plant test programs be designed to detect and correct unforeseen common mode design deficiencies (CMDD). Issue 125.I.5 was evaluated and not pursued further primarily due to the narrow scope of the common cause trigger and the impracticality of the proposed solution. However, an alternative approach to resolving the Finding 15 recommendation that included a broader scope of common cause failures (CCF) and a more practical approach was identified during the evaluation of Issue 125.I.5 and formed the basis for Issue 145.

The identified alternative approach consisted of assessing the benefits of improvements in existing in-service, refueling, and surveillance testing programs in operating reactors and improved startup testing for future plants. Such an assessment would focus on improvements in testing components and systems under conditions more representative of operational and DBA expectations with emphasis directed toward detection of all types of CCFs. This alternative approach, however, would be more effective as a long-term program and could make use of results from the IPE program and other ongoing research and regulatory programs to provide guidance for the prevention and detection of CCFs. Such guidance would also be useful to new plants because it could be used in the development of system design and the procedures for operating, maintaining, and testing the plants.

Testing of equipment has its limitations; in fact, testing can be an important cause of CCFs which occur when the testing does not reflect true demands of the equipment under operating conditions. For example, MOVs may work during a test but not during a true demand when there exists a high delta pressure across them. Much design basis testing cannot be performed in situ. Prototypical testing, on the other hand, is expensive and the application of prototypical testing to equipment in plants is sometimes not practical. Thus, it was believed that measures were needed to identify CCF precursors before they occur so that corrective measures could be taken.

Prior to the evaluation of this issue in February 1992, RES had performed basic research on procedures for identifying CCFs, the results of which were documented in NUREG/CR-4780[1465] and NUREG/CR-5460.[1466] The basic emphasis of the latest concepts involved evaluating the CCFs from a historical and plant-specific basis and evaluating the defenses of the plant to reduce the threat of the cause or protect the equipment from such causes. At that time, RES was also completing research on data analysis methods for detecting potential CCFs.

Related issues included: A-17, "Systems Interactions," which identified internal flooding as a significant concern and was expected to be analyzed by each licensee as part of the IPE program; the maintenance rule (10 CFR 50.65) and regulatory guide; A-9, "ATWS"; A-30, "Adequacy of Safety-Related DC Power Supplies"; A-35, "Adequacy of Offsite Power Systems"; A-44, "Station Blackout"; B-57, "Station Blackout"; B-56, "Diesel Generator Reliability"; C-13, "Non-Random Failures"; and 123, "Deficiencies in the Regulations Governing DBA and Single-Failure Criteria as Suggested by the Davis-Besse Incident of June 9, 1985."

Other NRC projects related to this issue were the Technical Specifications Improvement Program in NRR and the AEOD operating feedback study of solenoid-operated valves (NUREG-1275)[1079] which addressed widespread deficiencies that were found in the design, application, manufacture, maintenance, surveillance testing, and feedback of failure data. Many of the solenoid valve problems involved components not modeled in a PRA. Such component failures can be important to plant operation and safety.

Safety Significance

Prevention of CCFs is very important to plant safety. For highly redundant systems, CCFs can be a major cause of system failure. The TMI-2 and Davis Besse incidents were examples of scenarios involving CCFs. AEOD studies have shown the importance of CCFs, and PRAs routinely identify CCFs as important contributors to CDF and risk.

Possible Solutions

The possible solutions to this issue were:

(1) Provide information about CCFs to licensees for use in performing their IPE, and encourage licensees to conduct an engineering analysis and to provide training to plant personnel so they are aware of the importance of CCFs and the types of actions which increase the frequency of occurrence of CCFs and the types of actions and situations which can decrease the frequency of CCFs. Licensees could then voluntarily make changes in maintenance programs, testing, procedures, etc., to help reduce the potential for CCFs. This would be implemented by the NRC issuing an information notice to licensees. A report would be prepared to contain useful information about CCFs occurring in operating histories, identified in PRAs and IPE, and insights from RES CCF projects.

(2) Request licensees to perform a systematic engineering examination of the important CCFs identified in their IPEs and updates as they are made. Such analyses would provide insights into plant practices which will prevent or defend against CCFs, including hardware and human interactions. An example of a detailed engineering analysis of a PRA common cause event is contained in Section 4.2 of NUREG/CR-4780.[1465] This analysis focused on a detailed examination of battery common mode failures at a plant. The commonality found from this plant-specific analysis was attributed to maintenance of the batteries.

(3) Have licensees monitor dates of failures to recognize increased potential for CCFs. Where dates of component failures are clustered or grouped in time, instead of being spread over time randomly, statistical analysis of

this clustering can indicate when failures are not independent of each other, i.e., that they are subject to a common cause. This would be incorporated into the regulatory guide associated with the maintenance rule. This should have a positive impact in reducing those CCFs which are the result of inadequate maintenance practices. However, this will be dependent upon the ability of individual licensees to recognize CCFs as part of the monitoring and root cause analyses performed to investigate equipment failures and/or malfunctions.

(4) For a select group of important, highly reliable components (e.g., batteries and scram breakers) have licensees perform a detailed review of actual and potential failures to determine the extent that the failure or its root cause may affect multiple components.

PRIORITY DETERMINATION

Frequency Estimate

Table 3.145-1 contains a summary of the CCF contribution from four NUREG-1150[1081] internal events PRAs and the LaSalle PRA. The common cause contributions were those contained in the dominant accident sequence cut sets. The common cause terms were set to zero and a reduced CDF was calculated. This value represented the maximum amount the CDF could be reduced by the possible solution.

Table 3.145-1

CCF Contributions from Selected PRAs

Plant	Mean CDF/RY	CDF/RY With CCF = 0	Difference (/RY)	Difference (% of CDF)
Surry	3.2×10^{-5}	2.1×10^{-5}	1.1×10^{-5}	33.6
Sequoyah	5.3×10^{-5}	4.2×10^{-5}	1.1×10^{-5}	19.9
Peach Bottom	3.6×10^{-6}	3.2×10^{-6}	4.1×10^{-7}	11.6
Grand Gulf	2.1×10^{-6}	1.2×10^{-6}	8.5×10^{-7}	41.2
LaSalle	3.2×10^{-5}	1.3×10^{-5}	1.9×10^{-5}	59.4
Average	2.4×10^{-5}	1.6×10^{-5}	8.3×10^{-6}	33.8

It is recognized that not all common causes modeled in the PRAs can be reduced to zero. However, not all common causes are modeled in the PRAs and not all systems are modeled, or modeled in detail. Thus, this reduced CDF may be regarded as being representative of the amount the core damage could be reduced. On the other hand, the possible solutions may not be effective in eliminating the specific CDFs modeled in the IPEs. Therefore, it was assumed that the CDF attributed to CCFs will be reduced by a factor of 2, i.e., the possible solutions will be 50% effective in reducing and preventing CCFs. Based on the above considerations, the CDF reduction by reactor type was 5.35×10^{-6}/RY for PWRs (based on 2 PRAs) and 3.33×10^{-6}/RY for BWRs (based on 3 PRAs).

Consequence Estimate

The conditional release doses used in this analysis were based on the fission product inventory of a 1120 MWe PWR and a 1000 MWe BWR. Additional assumptions common to both reactor types were meteorology typical of a midwest site, a surrounding uniform population density of 340 persons per square mile within a 50-mile radius of the plant, an exclusion radius of one-half mile from the plant, no evacuation, and no ingestion pathways. Therefore, the estimated change in risk was intended to be representative of hypothetical generic PWR and BWR plants and not representative of any specific plant. The assumption of no evacuation provided a degree of conservatism for this analysis.

Based on NUREG/CR-2800,[64] average releases are 2.5×10^6 man-rem and 6.7×10^6 man-rem for PWRs and BWRs, respectively. Based on an average remaining lifetime of 28.8 years for a PWR, the estimated risk reduction associated with this issue was $(5.35 \times 10^{-6}/RY)(2.5 \times 10^6$ man-rem)(28.8 years) or 385 man-rem/reactor. Based on an average remaining lifetime of 27.4 years for a BWR, the estimated risk reduction was $(3.3 \times 10^{-6}/RY)(6.7 \times 10^6$ man-rem)(27.4 years) or 606 man-rem/reactor.

Cost Estimate

Industry Cost: If a plant is systematically evaluated by a licensee for common failure (Solution 2) or has its more important systems assessed for the potential for CCF (Solution 4), it was estimated that the cost would be approximately $200,000 (one staff-year).

Solution 3 deals with monitoring and analysis of failure information and failure dates of components. It was assumed that this activity will require one person part-time at a cost of $25,000/RY. For the average remaining plant life of 28 years, this cost was approximately $700,000/reactor.

In addition to the above, licensees would incur costs to implement any actions to correct potential CCFs identified from the evaluations proposed.

NRC Cost: The cost associated with Solution Item 1 (preparation of an information notice and a CCF summary report) was estimated to be about $200,000.

Total Cost: The maximum cost associated with the possible solutions would be $1.1M/reactor and would depend upon the possible solutions pursued; implementation would increase this cost.

Value/Impact Assessment

PWRs: Based on a potential risk reduction of 385 man-rem/reactor and a cost of $1.1M/reactor, the value/impact score was given by:

$$S = \frac{385 \text{ man-rem/reactor}}{\$1.1M/\text{reactor}}$$

$$= 350 \text{ man-rem/\$M}$$

BWRs: Based on a potential risk reduction of 606 man-rem/reactor and a cost of $1.1M/reactor, the value/impact score was given by:

$$S = \frac{606 \text{ man-rem/reactor}}{\$1.1M/\text{reactor}}$$

$$= 551 \text{ man-rem/\$M}$$

Other Considerations

(1) Effective maintenance is important to ensure that design assumptions and margins in the original design basis are either maintained or are not unacceptably degraded.[1467] In the design of nuclear power plants, an important safety margin is the redundancy of equipment to perform safety functions. This redundancy, however, can be degraded by CCFs. Therefore, defense against CCFs over the life of a plant is an important part of each licensee's maintenance program. If properly performed, the CCF monitoring activity and the root cause analyses conducted by licensees to investigate equipment failures and/or malfunctions should reduce CCFs that result from inadequate maintenance. However, the effectiveness of some defenses may be reduced because of aging and may need to be taken into consideration during license renewal.

(2) Assuming a 20-year renewal period for operating reactors, the estimated risk reduction for a PWR was $(5.35 \times 10^{-6}/RY)(2.5 \times 10^{6}$ man-rem)(48.8 years) or 653 man-rem/reactor. For a BWR, the estimated risk reduction was $(3.3 \times 10^{-6}/RY)(6.7 \times 10^{6}$ man-rem)(47.4 years) or 1048 man-rem/reactor.

CONCLUSION

Based on the potential risk reduction, this issue was given a medium priority ranking (See Appendix C). However, as part of the IPE program, licensees were requested to consider CCFs. Additionally, the regulatory guide to implement the maintenance rule (10 CFR 50.65) was expected to include monitoring of failure rates to look for common cause. This action essentially addressed Solution Items 2 and 3. However, since much information regarding CCF had been generated over the years, it was likely to be beneficial to pursue Solution Item 1. This action did not require any additional research and could be accomplished in the near term. Thus, this issue was considered to be nearly-resolved, to be closed out with publication of a staff report summarizing experience and insights on CCFs. In accordance with the RES evaluation,[1564] the impact of a license renewal period of 20 years will be considered in the resolution of the issue.

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ISSUE 146: SUPPORT FLEXIBILITY OF EQUIPMENT AND COMPONENTS

DESCRIPTION

Historical Background

This issue was identified[1477] by NRR when concerns were expressed that the seismic loading on equipment and pipe-mounted components may have been underestimated. These concerns could be divided into two sub-issues:

> Sub-Issue 1: On-site tests from the Lotung soil-structure interaction study and dynamic tests performed on concrete expansion anchor bolts[1478,1480] indicated that, in certain cases, some of the existing regulatory guidelines and industry practice on seismic design regarding the stiffness of anchorage in equipment and piping might potentially lead to underestimation of their seismic loadings.
>
> Sub-Issue 2: Substantial relaxation of anchorage bolt torque could occur after years of operation causing reduction in equipment and piping natural frequency; this could lead to higher seismic loading on equipment and piping than originally estimated.

Safety Significance

Sub-Issue 1: SRP[11] Sections 3.7.2, 3.9.2, and 3.10 provide guidance and criteria for seismic analysis of seismic subsystems (equipment and piping) when connected to the supporting seismic systems (buildings and structures). In order to simplify analytical effort, the common industry practice is to assume rigid and fixed attachments between the seismic subsystems and the supporting seismic systems. This means that the anchorage of the seismic subsystems (anchor base plate, anchor bolts or through-bolts, concrete and reinforcement in the area) is assumed to have rigid body characteristics. Therefore, the influence of the stiffness of anchor base plate and anchor bolts on the dynamic response is neglected. For a large number of anchoring systems, especially for those seismic subsystems having only a small mass as compared to that of the supporting seismic systems, this assumption is appropriate. However, in some cases, particularly in heavy equipment, this assumption can potentially lead to underestimation of seismic loadings.

Sub-Issue 2: After years of operation, relaxation of anchorage bolt torque could occur, causing reduction in equipment and piping natural frequency. Since the seismic loading on equipment and piping is determined on the basis of the response spectrum curve, this shift of seismic subsystem natural frequency could potentially increase the seismic response of equipment and piping.

In both the above-mentioned cases, the possible underestimation of seismic loadings could result in malfunction or failure of safety-related equipment, especially the heavy ones, thereby potentially leading to increased CDF and risk to the public.

Possible Solution

Tests and collection of seismic data indicated that piping systems designed under existing Code provisions appeared to be quite rugged against seismic excitation. Therefore, the concern of this issue was limited to equipment anchorage only, especially those for heavy equipment. Possible solutions to the two sub-issues were as follows:

Sub-Issue 1

(1) Develop guidelines for the re-analysis of equipment anchorage.

(2) For safety-related seismic subsystems, especially heavy equipment, perform plant-specific re-analysis of anchorage considering the stiffness of anchor base plates and anchor bolts on the dynamic response, the local response of the supporting building structure, etc. A bounding study may be needed as this analysis most likely will involve some sort of detailed finite element analysis and could be very costly.

(3) Modify equipment hardware, if required as a result of re-analysis.

Sub-Issue 2

(1) The Seismic Qualification Utility Group (SQUG), with NRC participation, developed detailed plant-specific walk-down review guidelines (review of expansion anchor bolts being part of this) for the resolution of Issue A-46. The IPEEE will also utilize the SQUG review guidelines in its plant-specific walk-down reviews. Thus, this sub-issue was addressed in the resolution of Issue A-46 and the implementation of the IPEEE.

(2) For new designs, NRC was expected to conduct research on anchor bolt capacity and dynamic behavior for individual and groups of anchor bolts. When definitive recommendations were available, suitable changes to the SRP[11] were to be implemented.

PRIORITY DETERMINATION

Separate analyses were made for operating and future plants.

OPERATING PLANTS

Assumptions

As mentioned above, tests performed and collection of seismic data indicated that piping systems designed under existing Code provisions appeared to be quite rugged against seismic excitation. Therefore, the concern of this issue was limited to equipment anchorage only, especially those for heavy equipment. It was assumed that this issue affected all 111 nuclear plants in operation at the end of 1991 (74 PWRs and 37 BWRs). These plants were assumed to have an average remaining life of 24 years.

It was assumed that none of the 111 plants had done a re-analysis of the anchorage stiffness of seismic subsystems. Further, it was conservatively assumed that, as a result of re-analysis, half of the 111 plants would require some degree of hardware modification.

Frequency Estimate

The source of quantitative risk information was a study performed[1065] to identify seismic risk-sensitive components in nuclear power plants during and after a seismic event. This study used PRA methodology to expand seismic risk-sensitivity analyses by accounting for seismicity and component fragility data taken from existing nuclear power plant PRAs. This modified PRA analysis consisted of event trees with seismic-induced initiating events (such as seismic-induced small LOCA, transient, LOSP, etc.), and seismic as well as non-seismic related failures in the core damage sequences. It was estimated that for the base case, the affected annual CDF from seismic events was about 4.2×10^{-6}/RY for a hypothetical hybrid PWR plant and 9.1×10^{-5}/RY for a hypothetical hybrid BWR plant. However, based on the findings of the more up-to-date NUREG-1150,[1081] this estimation[1065] for a PWR plant was about one order of magnitude too low and, therefore, was revised to 4×10^{-5}/RY for this analysis. In addition, the estimated annual CDF from seismic events for the hypothetical hybrid BWR plant used in NUREG/CR-3357[1065] was atypical due to seismic inadequacy in the plant-specific building structures and, in view of NUREG-1150,[1081] was also reduced to 4×10^{-5}/RY. Therefore, applying these corrections resulted in an annual CDF estimate of about 4×10^{-5}/RY for both PWR and BWR plants.

Because of the above-mentioned atypical seismic inadequacy in building structures used for the hypothetical hybrid BWR plant in NUREG/CR-3357,[1065] it was assumed that the results of that study for a PWR will be applicable and representative of all operating plants. The rest of this evaluation was based on this assumption.

In NUREG/CR-3357,[1065] it was stated that, for the hypothetical hybrid PWR plant studied, building structural failures contributed 38% to the annual CDF from seismic events; the remaining 62% was contributed from failures of equipment (60%) and piping (2%).

To estimate the risk reduction achievable, the adjusted case of NUREG/CR-3357[1065] assumed upgrades ("hardening") to various equipment and piping systems such that there was a factor of 5 increase in the median peak ground acceleration (the level of peak ground acceleration at which a component has a 50% probability of failure) for these equipment and piping systems. It was assumed that all the upgrades to the equipment were done to the equipment anchorages where the anchorages were modified to be rigid.

To calculate the changes in CDF that could result from implementation of the possible solution, the contribution from equipment to base case seismic CDF (i.e., base case CDF from seismic events) needed to be calculated first. The contribution to the base case seismic CDF from equipment was $(4 \times 10^{-5}/\text{RY})(0.60) = 2.4 \times 10^{-5}/\text{RY}$.

The reductions in CDF that result from implementation of the solution were obtained by multiplying the above numbers by a reduction factor of 0.28 to CDF due to equipment upgrade.[1065] Therefore, the CDF reduction was given as follows:

ΔCDF = (contribution to base case seismic CDF from equipment) x (reduction factor to CDF due to equipment anchorage upgrade)
= $(2.4 \times 10^{-5}/RY)(0.28)$
= $6.8 \times 10^{-6}/RY$

Consequence Estimate

The public risk reduction associated with the solution was obtained from the product of the change in CDF and public dose consequences. Because the core damage sequences encompass all release categories, a weighted average consequence value was developed to approximate the consequences of a core damage accident. The weighted average consequence value of 4.9×10^6 man-rem/event was calculated for all affected release categories using the dose consequences from NUREG/CR-2800.[64] Thus, the potential public risk reduction was 34 man-rem/RY.

It was conservatively assumed that after evaluation, half of the 111 plants would need some sort of hardware modification to equipment anchorage. Thus, the total estimated public risk reduction resulting from implementation of the possible solution was (34)(55)(24) man-rem or 45,000 man-rem.

Cost Estimate

Industry Cost: Implementing the possible solution at each plant would be done in two parts: (1) perform an equipment anchorage evaluation to assess the effects of actual anchorage stiffness on equipment seismic response; and (2) modify the anchorage if needed.

It was assumed that 2 man-years at a cost of $2,270/man-week would be needed to perform the re-analysis at each plant. Further, it was assumed that other costs for re-analysis (computer costs for finite element analysis, retrieval of original equipment anchorage design information, etc.) would be $100,000. This resulted in a cost of $340,000/plant and a total of $38M for all 111 plants.

For the 55 plants that required some degree of anchorage hardware modifications, the cost/plant was based on the estimate of equipment support modification in Table 1 of NUREG/CR-3875.[1064] This cost of support modification included two parts: labor (including engineering time) and material. For heavy equipment such as large valves, large pumps (both horizontal and vertical), and diesel generators, the average cost ranged from $2,000 to $50,000. A total cost of $500,000/plant was assumed. A 10.08 adjustment factor was applied for labor productivity effects for work in radiation zones and congested areas, manageability, and access/handling difficulties.[961] Assuming ⅓ of the hardware modification would encounter these difficulties resulted in a cost of $2M/plant or $111M for the 55 affected plants.

Therefore, the total plant implementation costs were $149M and included $38M for the analyses and $111M for the hardware modifications and associated labor.

NRC Cost: NRC implementation of the solution could be quite extensive. The work scope needed to develop the equipment anchorage re-analysis screening criteria and/or re-analysis guidelines could include the following: (1) relevant literature search and evaluation of the potential impact; (2) actual study of major subsystems of selected plants, including reviewing the models, assumptions,

and calculations; (3) if needed, some small-scale experiments to confirm the results of the above studies; and (4) recommendations to improve the existing conditions in operating plants.

Items 1, 2, and 4 were estimated to require approximately 2 man-years of labor to develop, review, and approve. At a rate of $100,000/man-year, the estimated cost was $0.20M.

Item 3 was estimated to require 1 man-year of labor to prepare the test procedures, QA activities, and analysis of test results. Labor costs were estimated at $100,000/year, for a total program cost of $0.35M. A generic letter directed to all operating plants would be required. It was estimated[961] that the labor requirement to issue a generic letter was 6 man-weeks. At a rate of $2,270/man-week, this cost would be $0.01M.

NRC reviews of licensee submittals in response to the generic letter were assumed to be 5 man-weeks/plant. At $2,270/man-week, the total cost for 111 plants was $1.3M. Thus, the total NRC cost is $(0.20 + 0.35 + 0.01 + 1.3)M or $1.86M.

Total Cost: The total industry and NRC cost for implementation of the possible solution was estimated to be $(149 + 1.86)M or approximately $151M.

Impact/Value Assessment

Based on a potential public risk reduction of 45,000 man-rem and a cost of $151M, the impact/value ratio was given by:

$$R = \frac{\$151M}{45{,}000 \text{ man-rem}}$$

$$= \$3{,}355/\text{man-rem}$$

Other Considerations

(1) Using the assumptions in "Industry Cost," it was estimated that about 30,000 man-hours/plant would be required for hardware modification in radiation zones. Assuming a dose rate of 0.025 rem/hr,[64] the total occupational dose for 55 plants was estimated to be (55 plants x 0.025 rem/hr x 30,000 man-hour/plant) or 41,000 man-rem.

(2) The occupational dose reduction due to accident avoidance was calculated from the reduction in CDF multiplied by the assumed accident dose of 19,860 man-rem.[64] The possible solution would reduce the CDF in 55 plants that have an occupational dose rate reduction of (19,860 man-rem x 6.8 x 10^{-6}/RY) or 0.14 man-rem/RY. With the 55 plants having an average remaining life of 24 years, this resulted in a best estimate total occupational dose reduction due to accident avoidance of 185 man-rem.

(3) The accident avoidance cost savings were estimated to be the product of the CDF reduction (6.8 x 10^{-6}/RY), the estimated cost of a core-melt accident ($1.65 Billion), and 55 plants with an average remaining life of 24 years. This resulted in a total cost of $14.8M.

FUTURE PLANTS

Assumptions

It was assumed that there would be 10 future plants and half of them would need some sort of hardware modification; future plants were defined as plants seeking licenses (CP/OL) or combined licenses (per 10 CFR 52). Furthermore, the usual assumption of 40-year plant life was assumed for both types of plants.

Frequency/Consequence Estimates

Just as in the case of the backfit analysis for operating plants,

Reduction in CDF	=	6.8×10^{-6}/RY
Public Risk Reduction	=	34 man-rem/RY

For 5 plants with an average remaining life of 40 years, the total public risk reduction was (34)(5)(40)man-rem or 6,800 man-rem.

Cost Estimate

Industry Cost: Assuming that the cost/plant was the same ($340,000) to perform the seismic analysis during the design stage to consider the effects of equipment anchorage stiffness, the total cost for 10 plants was estimated to be $3.4M.

NRC Cost: It was assumed that the NRC costs would be $0.2M to develop evaluation guidelines, $0.35M for a test program, and $0.5M to update relevant Regulatory Guides and SRP[11] Sections. Thus, the total NRC cost was estimated to be $(0.2 + 0.35 + 0.5)M or $1.05M.

Total Cost: The total industry and NRC cost associated with the possible solution was $(3.4 + 1.05)M or approximately $4.45M.

Impact/Value Assessment

Based on a potential public risk reduction of 6,800 man-rem and a cost of $4.45M, the impact/value ratio was given by:

$$R = \frac{\$4.45M}{6{,}800 \text{ man-rem}}$$

$$= \$654/\text{man-rem}$$

Other Considerations

(1) The equipment seismic experience data base collected by SQUG in the resolution of Issue A-46 could provide some clue regarding the performance of equipment under seismic loadings. This data base ("Summary of the Seismic Adequacy of Twenty Classes of Equipment Required for the Safe Shutdown of Nuclear Plants," EQE, Inc., February 1987) was collected from over 100 industrial facilities (fossil and hydroelectric power plants, electric distribution stations, petrochemical plants, and other large industrial facilities) in the strong motion areas of 13 earthquakes that have occurred in the U.S. and Latin America since 1971. It indicated that

heavy equipment (e.g., large pumps, valves, large diesel generators, etc.) generally performed well under earthquake loadings, in spite of the fact that seismic loadings were not considered in the original designs for most of the plants in this data base.

(2) For U.S. nuclear power plants, seismic loadings were required by the NRC to be considered in the original design, even though the local anchorage stiffness effects on equipment were not routinely evaluated. Furthermore, for existing OL/CP plants, the accident avoidance cost savings and occupational dose reduction due to accident avoidance were not significant, when compared to the cost and doses used in the impact/value score, and the occupational dose increase (41,000 man-rem) due to implementation of the possible solution was nearly the same as the best estimate public risk (45,000 man-rem) that could be reduced.

(3) For future plants, the total reduction in public risk would be less than that for existing plants since it was assumed there would be fewer future plants than the existing plants. However, for future plants, the impact/value consideration would be more favorable since equipment anchorage stiffness effects could be evaluated in the design and analysis stage and backfit would not be required. In addition, the ORE to forward-fit future plants was limited to operation and maintenance and should be minimal.

CONCLUSION

Based on the impact/value assessment and total public risk reduction potential and using the revised guidelines of SECY-93-108,[1479] this issue had a borderline medium priority ranking for operating plants and a medium priority ranking for future plants. However, the seismic PRA model used in NUREG/CR-3357[1065] (which was issued in 1983 without the benefit of the SQUG equipment seismic experience data base) had inherent large uncertainties associated with it. Furthermore, as discussed above, other factors such as the large occupational dose increase due to implementation of the resolution needed to be considered. When all these factors were considered together with the impact/value assessment and total reduction in public risk, the priority ranking was judged to be low for operating plants and medium for future plants.

For operating plants, no further action was needed on Sub-Issue 1 and Sub-Issue 2 was covered in the implementation of the resolution of Issue A-46 as well as in the IPEEE Program.[1222] For future plants, the following recommendations were made:

(1) Sub-Issue 1: There was a need to reflect the uncertainty in anchorage stiffness assumption for heavy equipment. Pertinent sections of the SRP[11] should be revised to adequately treat anchorage stiffness assumptions.

(2) Sub-Issue 2: NRC was conducting research on anchor bolt capacity and dynamic behavior for individual and groups of anchor bolts. When definitive recommendations were available, appropriate changes to the SRP[11] should be made.

In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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ISSUE 149: ADEQUACY OF FIRE BARRIERS

DESCRIPTION

Historical Background

This issue was raised in SECY-89-170[1320] and addressed the effect of premature failure of fire barriers on CDF. Concern for fire barriers arose as a result of an NRC-sponsored Fire Risk Scoping Study[1211] which focused on existing fire protection practices for control rooms, remote shutdown areas, control transfer areas, and local control areas.

10 CFR 50 Appendix R and the SRP[11] contain requirements for the protection of safety-related equipment from fires and related fire-suppression activities. Tests on fire barrier components are conducted in accordance with industry standards ASTM-E119 (fire barriers in general), NFPA-251 (walls and columns), and NFPA-252 (doors and dampers). The tests assure a certain degree of fire barrier reliability; however, they do not simulate actual fire conditions. Test procedures do not include the requirement for component testing under a pressure gradient.

Fire barriers, typically walls or doors, are designed to ensure that a fire will be contained within its enclosure to the extent possible. Tests at SNL[1211] suggested that fire barriers in operating nuclear plants might not properly contain the spread of fires because: (1) barrier penetration seals, doors, and dampers may not be sufficiently reliable to prevent fire spread; and (2) deficiencies may exist in the methods used to rate fire barriers.

Safety Significance

A rapid energy release from a fire could generate a pressure differential across a fire barrier which could result in a premature failure of the barrier. Many variables such as compartment air tightness, materials, and geometry will affect the magnitude of the pressure gradient. Studies[1211] have shown that core-melt frequency is sensitive to fire barrier reliability. This issue affected all LWRs.

Possible Solution

A possible solution to this issue involves licensee searches for plant-specific vulnerabilities, an assessment of the reliability of fire barriers based on site-specific experience, and modifications, if necessary.

PRIORITY DETERMINATION

Assumptions

It was assumed that 90 PWRs and 44 BWRs with an average remaining operating life of 28.3 years were affected by this issue. It was also assumed that 25% of all plants would be required to make some modifications. Cost estimates were based on 1982 dollars.

Frequency Estimate

An estimate of the core-melt frequency due to fire barrier failure was calculated based on the operating history of nuclear power plants. At the time of this evaluation, there were approximately 1700 RY of nuclear power operation. Over this entire period, the only nuclear power plant fire that approached inducing a core-melt was the Browns Ferry fire of March 22, 1975. Thus, a crude but reasonable point estimate for the frequency of a fire with at least the potential core-melt impact of Browns Ferry is 1/(1,700 RY) or 6×10^{-4}/RY.

However, the Browns Ferry fire did not result in a core-melt. It was estimated[64] that the maximum probability for core damage, given the Browns Ferry fire, was 0.03, occurring 2.5 hours from the start of the fire and assuming all relief valves failed after 30 minutes and remained so for at least 12 hours. Applying this conservative estimate to the point estimate for a Browns-Ferry-type fire, a conservative point estimate for the frequency of core damage from fire was calculated to be $(0.03)(6 \times 10^{-4}/RY) = 1.8 \times 10^{-5}/RY$.

Since the Browns Ferry fire represented one in which a fire barrier "failed" (the barrier had previously been breached by non-fire-related activities), this estimate would be a conservative one for core-melt frequency due to fire barrier failure. It lies within the range 10^{-5}/RY to 10^{-4}/RY estimated in NUREG/CR-5088,[1211] comparing well with the geometric mean (3×10^{-5}/RY) over that range.

Nuclear power plants have made numerous improvements since the Browns Ferry fire to reduce the likelihood of a fire-induced core-melt. Moreover, increased pressures leading to barrier failure resulting from a fire within a compartment in a U.S. nuclear power plant is highly unlikely and is not considered credible. This is based on the fact that compartments are sufficiently ventilated (not fully air-tight), have low and not easily ignitable combustible contents, are provided with early warning fire/smoke detection capability, and, in areas where fire hazards exist that could affect safe shutdown capability, automatic suppression capability is provided.[1365] Therefore, it would be reasonable to lower the above conditional probability for core damage from 0.03 to 0.0003 (i.e., a factor of 100 reduction). This resulted in a point estimate for the core-melt frequency due to fire barrier failure of 1.8×10^{-7}/RY. Assuming that a 90% reduction in the failure probability of a fire barrier is attainable,[1211] the adjusted case core-melt frequency was estimated to be 1.8×10^{-8}/RY.

Consequence Estimate

Based on PNL calculations,[64] the average LWR dose factor is 3.3×10^{6} man-rem. Using this value, the base case risk was estimated to be $(1.8 \times 10^{-7}/RY)(3.3 \times 10^{6}$ man-rem) or 0.594 man-rem/RY; the adjusted case risk was $(1.8 \times 10^{-8}/RY)(3.3 \times 10^{6}$ man-rem) or 0.0594 man-rem/RY. Thus, the potential risk reduction is (0.59 - 0.0594) man-rem/RY or 0.53 man-rem/RY. For 25% of the 134 affected plants with an average remaining life of 28.3 years, the total public risk reduction was estimated to be (0.53)(0.25)(134)(28.3) man-rem or approximately 500 man-rem.

Cost Estimate

Industry Cost: It was estimated[64] that 6 man-months will be required to search all 112 operating plants for the potential vulnerabilities identified in this issue. This effort would include a review of plant drawings and existing fire

hazards analyses and a walk-through inspection of potentially susceptible areas. Assessment of the reliability of fire barriers, based on site-specific experience, was estimated to require 6 man-months. This effort will involve reviewing the existing fire hazards analyses, estimating the conditions likely to be experienced in an actual fire, and performing sensitivity studies. Based on a cost of $100,000/man-year, the industry cost for the above 12 months of effort will be $100,000/plant. For the 112 operating plants, this cost will be $11.2M.

Following licensee review and assessment of existing fire barriers, some modifications at 25% of the 112 operating plants was conservatively estimated to require $50,000/plant for a total cost of $1.4M. Operation and maintenance of improvements would not incur any additional costs. The cost for future plants was considered to be negligible in comparison to that for OLs.

NRC Cost: It was assumed that the staff will have to issue an information notice or a generic letter with a possible TS change. Based on NUREG/CR-4627,[961] this cost was estimated to be $11,000/plant. For 112 plants, this cost will be $1.23M. Review and approval of licensee proposals was estimated to require 2 man-weeks/plant for the 28 operating plants that will require modifications. At $2,270/man-week, this cost was estimated to be approximately $127,000.

Total Cost: The total industry and NRC cost associated with the possible solution to this issue was approximately $14M.

Value/Impact Assessment

Based on an estimated public risk reduction of 500 man-rem and a cost of $14M, the value/impact score was given by:

$$S = \frac{500 \text{ man-rem}}{\$14M}$$

$$= 36 \text{ man-rem/\$M}$$

Other Considerations

Plant TS require compensatory measures to be taken in the event that a fire barrier is made inoperable. Generally, a fire watch is established for the affected barrier and for the areas which it provides fire separation. In addition, since the Browns Ferry fire, there has not been a case where a fire in a nuclear power plant has challenged the integrity of a fire barrier or has contributed to its failure as a result of differential pressure. In response to the IPEEE program,[1354] licensees will have to justify their fire barrier maintenance programs in support of justifying the adequacy of their fire barriers.[1365]

CONCLUSION

Based on the potential public risk reduction, this issue was given a LOW priority ranking (See Appendix C). In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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ISSUE 150: OVERPRESSURIZATION OF CONTAINMENT PENETRATIONS

DESCRIPTION

Historical Background

This issue was identified[1330] by DSIR/RES and addressed the concern for overpressurization of containment piping penetrations following a containment isolation and subsequent heat-up.

Containment isolation at all nuclear power plants ensures that radioactive materials are contained if an accident or inadvertent release of such materials occurs. Isolation is provided for all piping systems that penetrate the containment. Double barriers are provided to ensure that no single failure of an active component can result in a loss of this isolation function. Typically, this double barrier system is provided by isolation valves inside and outside containment. When containment isolation is required because of an accident or inadvertent release of radioactive materials, these valves are closed to prevent leakage of radioactive materials to the environment.

Safety Significance

Overpressurization of the containment piping penetrations could potentially occur during an accident involving a significant increase in the containment temperature. This might occur when water that is trapped between the inner and outer containment isolation valves is heated and expands. Theoretically, heating a constant volume of water from 100°F and 100 psia to 200°F would increase the pressure to 3000 psia. This pressure increase could fail the penetration or the isolation valves and could provide a direct flow path to the environment from the potentially contaminated containment atmosphere. The pressure increase is mitigated somewhat by the penetration itself expanding because of the temperature increase, as well as the possibility that the isolation valves will not be leak-tight and thus will not pressurize fully.

Possible Solution

A possible solution to this issue was to provide a mechanism for preventing water from becoming trapped or for relieving the pressure that could build up in the piping systems between the inner and outer containment isolation valves. Licensees would need to perform thermal and structural analyses of the penetration systems to determine which penetrations, if any, were susceptible to such failure. A pressure relief system would be needed to prevent the pressure increase from failing the penetration. This pressure relief system could consist of the following:

(a) Check valves inside the reactor building instead of the inner containment isolation valves. These valves would prevent water from becoming trapped between the two isolation valves but is only viable for penetrations with flow into containment.

(b) A method to provide pressure relief, such as a rupture disk or safety valve. A storage tank might be needed to contain blowdown liquid or vapor that would be forced through the pressure relief equipment when the equipment is operated.

PRIORITY DETERMINATION

Assumptions

This issue does not directly impact the potential for a core damage accident but addresses a plant's ability to contain radioactive materials that might be released during a core damage accident. Thus, the only concern was the probability of containment failure resulting from the failure of containment isolation. Therefore, to estimate the potential public risk reduction, the effect of the possible solution on the probability of containment failure, assuming a core damage event has occurred, was evaluated.

It was assumed that 90 PWRs and 44 BWRs with average remaining lives of 28.8 and 27.4 years, respectively, were affected by this issue. Oconee 3 and Grand Gulf 1 were used as the reference PWR and BWR, respectively.

Frequency Estimate

The Oconee 3 PRA[54] addressed failure of, or leakage through, containment penetrations as a potential failure mode of the containment. For Oconee 3, the probability of containment penetration leakage (β), given the occurrence of a core damage accident, was estimated to be 7.3×10^{-3}. This probability was used as the base case value for Oconee 3.

The Grand Gulf 1 PRA[54] did not explicitly evaluate containment penetration leakage because none of the accident sequences involving containment isolation failure were found to be among the dominant sequences from a public risk perspective. However, the Grand Gulf 1 PRA was based on WASH-1400[16] which did assess the conditional probability of containment isolation failure (β). Therefore, the base case value used in this analysis was based on the WASH-1400[16] analysis.

The probability of containment isolation failure is dependent upon the specific core damage sequence that occurs before containment failure.[16] As a result, the containment isolation failure probability depends on the prior success or failure of the various engineered safeguards functions. Based on information in Appendix V of WASH-1400,[16] a value of 4×10^{-2} was selected as a representative probability for containment isolation failure. This value represented the weighted average of the range of possible values based on the number of observations in WASH-1400.[16]

The release categories associated with containment isolation failure for Oconee 3 are PWR-4 and PWR-5. For Grand Gulf 1, the affected release categories were not explicitly stated in NUREG/CR-2800[64] or NUREG/CR-1659.[54] It was noted in WASH-1400[16] and a PRA[889] of Oconee 3 that relatively high containment leakage, attainable from failure of containment isolation, would prevent failure of the containment building from potential overpressure caused by H_2 gas explosions. Consideration of the containment isolation failure mode was therefore incorporated into accident sequences involving containment overpressure events

caused by gas generation, as shown in Appendix B of NUREG/CR-2800.[64] A new base case risk value was developed for all BWR accident sequences that involve containment overpressure events. To accomplish this, the core damage sequences presented in NUREG/CR-2800[64] that could result in containment overpressure were modified to incorporate the base case containment isolation failure probability, rather than the containment overpressure probability. This had the effect of creating a set of new accident sequences that included containment isolation failure events.

The adjusted case values of the affected parameters were estimated by adding to the base case values the probability of failure of the penetration system (failure of one or more penetrations) that would arise from overpressurization. A conservative approach was taken to develop a new containment leakage sequence of events that incorporated the potential for overpressurization. This sequence consisted of the following events: (1) containment isolation is successful; (2) water becomes trapped between inner and outer isolation valves; (3) containment heating causes heating and expansion of the water between the isolation valves; and (4) the water expansion causes the penetration to fail, such that a leakage path occurs between the containment atmosphere and the environment. Based on this sequence of events and using the rare event approximation, the additional probability of containment system failure was obtained from the product of the following terms:

N	=	number of penetrations that are susceptible to overpressurization
P[1]	=	probability water becomes trapped between isolation valves
P[2]	=	probability inboard and outboard isolation valves are leak-tight
P[3]	=	probability penetration overpressurizes to rupture, given that the penetration is leak-tight and full of water.
P[N]	=	probability that the penetration fails in a manner that results in a leakage path from the containment atmosphere to the environment, given that the penetration ruptures due to overpressurization.

N depends on the types of penetrations and isolation valves at each plant. Only liquid penetrations are susceptible to this type of failure and penetrations provided with check valves are not. To determine the value for N, the description of containment penetrations given in NSAC-60[889] was assumed to represent both PWRs and BWRs. A total of 62 penetrations were listed, of which, 36 were provided with check valves or were not liquid-carrying lines and were not susceptible to this containment failure sequence. Therefore, the value of N was 26.

No information was available to calculate P[1]. Containment isolation valve closures are timed such that one valve closes slightly sooner than the other to prevent water from becoming trapped between the valves. Therefore, this event could be caused by failure of the containment isolation system control logic or

circuitry to function as intended, or by failure of the valve to close when intended. P[1] was assigned a value of 0.5.

In this analysis, P[2] was set equal to unity. Thus, no credit was taken for the fact that penetration overpressurization would not occur if one of the isolation valves were not leak-tight. It was estimated that there was approximately a 30% chance that one of these valves would not be leak-tight.[1331]

To assist in estimating P[3], a simplified engineering analysis was performed by DSIR/RES to determine the stress and strain that a penetration would experience, assuming that it is leak-tight and full of water. For the purposes of the analysis, a typical penetration was approximated as a 2" diameter, 12" long cylinder fabricated of steel and having a yield point of 30 ksi. Assuming that the water was initially at 100°F and its temperature increased to 200°F as a result of an accident, it was calculated that the hoop stress would exceed the yield point. However, the volume of the cylinder would only have to increase 2.6% to accommodate the expansion of the water. This corresponded to a plastic strain of 1.3% in the diameter of the penetration, conservatively assuming no plastic strain in the axial direction. If the water were heated to 300°F, the diametric plastic strain needed to accommodate the expansion of the water would be 3.8%, again conservatively assuming no plastic strain in the axial direction. These values of strain were far below the values that would be expected to cause rupture of the penetration. Also, as expansion of the penetration volume occurs due to plastic deformation, the pressure of the trapped water decreases, further decreasing the likelihood of rupture. Using the above information, but considering that there is some probability that the material used to fabricate the penetration has an undetected flaw, the value of P[3] was estimated to be 10^{-4}.

For there to be a leak path that satisfies the definition of P[4], there must be a failure inside and outside the containment. One possibility is that the penetration rupture "runs" past the containment vessel. The other possibilities involve failures of both containment isolation valves, or the containment penetration and one isolation valve. Such failures must be simultaneous since the failure of one component relieves the pressure and eliminates the possibility of sequential failures. It was estimated that the value of P[4] was 0.1.

Based on the above estimates, the additional probability of containment system isolation failure was the product of N, P[1], P[2], P[3], and P[4], and was approximately $(26)(0.5)(1)(10^{-4})(0.1) = 1.3 \times 10^{-4}$.

Consequence Estimate

Incorporating the values into the Oconee 3 and Grand Gulf 1 PRAs resulted in a potential public risk reduction of 1.3×10^{-2} man-rem/RY and 3×10^{-3} man-rem/RY, respectively. Thus, the total potential public risk reduction was about 40 man-rem for all 134 affected plants.

Cost Estimate

Industry Cost: To implement the possible solution, licensees would be required to perform analyses to determine if certain penetrations were vulnerable to overpressurization following containment heat-up. These analyses were estimated to require 4 man-weeks/plant. In addition, safety analyses and QA-related

activities would be needed because of the installation of hardware inside containment that requires considerable attention to QA in designing the penetrations' pressure relief systems. Two man-weeks of labor per penetration were estimated for the design and safety analyses. The number of vulnerable penetrations was assumed to be 20% of the total penetrations without check valves, or 7 penetrations. Therefore, at 2 man-weeks/penetration, 14 man-weeks/plant would be required.

Installing new hardware within containment at operating plants (i.e., backfit) would require about 1 man-week of labor in radiation zones; plants under construction (i.e., forward-fit) would not require labor in radiation zones. The material costs were estimated to be $900/penetration and $6,300/plant, including labor for pipefitters, welders, radiation monitoring staff, and instrument technicians. For forward-fit plants, the hardware costs remained the same, but labor costs would be reduced because personnel would not be working in radiation zones. Therefore, a 50% reduction in labor requirements was estimated, i.e., 0.5 man-week/plant.

Based on the above estimates, the total labor required was 19 man-weeks/plant for backfit plants and 18.5 man-weeks/plant for forward-fit plants. Therefore, at $2,270/man-week, the estimated industry labor cost was $43,000/backfit-plant and $42,000/forward-fit plant. With a total of 71 backfit plants and 63 forward-fit plants, the total estimated industry implementation cost was $6.5M.

It was estimated that 28 man-hours/RY would be required to conduct periodic (monthly) testing of the pressure relief system. At $2,270/man-week, this cost was $1,589/RY. For the 134 plants, the total estimated cost for operation and maintenance was $6M. Using a 5% discount rate, the present worth of the recurring costs associated with plant maintenance and operation was $3.3M.

NRC Cost: It was estimated that 6 man-months would be required for the staff to develop acceptable methods, data, and acceptance criteria for licensees to use when evaluating the vulnerability of penetrations to the overpressure phenomenon analyzed in this issue. At $2,270/man-week, the total cost for this development was $54,000.

About 2 man-weeks/plant were estimated for reviewing and evaluating licensee calculations of the stresses within the penetrations and for reviewing the design, safety analyses, and QA documentation for the penetration pressure relief systems. At a cost of $4,500/plant, the total cost for this effort was estimated to be $600,000.

After implementation, the NRC would have to inspect the operation and maintenance of the penetration isolation systems; 1 man-hour/RY was estimated as sufficient for NRC review of each system. Therefore, the annual labor requirement was 0.18 man-week/RY for seven such systems. At $2,270/man-week, the total cost for the inspection of the 134 affected plants was $1.5M. Assuming a 5% discount rate, this cost was $880,000.

Total Cost: The total estimated industry and NRC cost associated with the possible solution to this issue was estimated to be $11.3M.

Value/Impact Assessment

Based on an estimated public risk reduction of 40 man-rem and a cost of $11.3M for the possible solution, the value/impact score was given by:

$$S = \frac{40 \text{ man-rem}}{\$11.3M}$$

$$= 3.5 \text{ man-rem/\$M}$$

Other Considerations

(1) For backfit plants, an estimated 5 man-hours/penetration of labor in a radiation zone would be required and, assuming 7 penetrations/plant, the total ORE would be 35 man-hours/plant. The dose rate was assumed to be 25 millirem/hour, which was representative of the dose rate inside containment during reactor shutdowns. The implementation dose was therefore estimated to be about 0.9 man-rem/plant. For the 71 backfit plants, the ORE was greater than the total averted public dose.

(2) Routine testing and inspection of the penetration pressure relief systems were assumed to occur once every 30 days, similar to testing of the containment isolation valves. The testing was assumed to be performed by a 2-man team and to last about 10 minutes. Assuming 7 penetrations to be tested, the total operation and maintenance dose was estimated to be about 0.7 man-rem/RY.

(3) The public risk reduction estimated for this issue was overestimated for several reasons. First, no credit was taken for the protection from overpressure that would be provided if one of the isolation valves were not leak-tight. Investigation of a previous containment issue indicated that there was approximately a 30% chance that one of the valves would not be leak-tight.

(4) The costs were estimated assuming that the containment isolation systems were located away from the containment building wall. This is not the case for many of the isolation valves which are located adjacent to the containment walls. This assumption tended to minimize the costs because they would be clearly higher with modification of the containment structure to accommodate the pressure relief system. As a result, the cost estimates provided above were believed to be low.

CONCLUSION

The estimated public risk associated with overpressurization of containment penetrations was not significant. Based on the value/impact assessment and the staff's simplified engineering analysis, this issue was placed in the DROP category (See Appendix C). In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1331. NUREG/CR-4220, "Reliability Analysis of Containment Isolation Systems," U.S. Nuclear Regulatory Commission, June 1985.

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ISSUE 151: RELIABILITY OF ANTICIPATED TRANSIENT WITHOUT SCRAM RECIRCULATION PUMP TRIP IN BWRs

DESCRIPTION

Historical Background

This issue was identified in a DSIR/RES memorandum[1329] which addressed the concern for the reliability of breakers used to trip the recirculation pumps at high pressure or low water level signals during ATWS mitigation in BWRs. A staff review of BWRs that experienced failures of breakers in the recirculation pump trip (RPT) system was documented in AEOD/E804.[1328]

If a plant transient requiring a reactor scram occurs and the scram function does not occur, then an ATWS event exists. To lessen the effects of an ATWS event, negative reactivity must be added to the reactor core by tripping the recirculation pumps. Negative reactivity is added as a result of the ensuing steam voiding in the core area as the core flow decreases, thereby decreasing the power generation and limiting the power or pressure disturbance.

Plants equipped with GE AKF-25 circuit breakers have experienced failures of the field breakers in the RPT system which were caused by binding of the trip latch mechanism and misadjustment of the breakers' mechanical linkage. GE issued a service information letter which attributed the circuit breaker failures to misadjustment or lubrication problems and suggested corrective actions and maintenance practices to improve the breakers' performance. In addition, Information Notice No. 87-12[1322] was issued by the NRC to all BWR licensees to alert them of potential problems with these circuit breakers.

Safety Significance

A RPT breaker is included in the design of plants to automatically trip the recirculation pump on high vessel pressure or low reactor water level during an ATWS event. If the RPT breaker fails to trip on demand, the reactor could experience continued power generation resulting in high suppression pool temperature. This issue affected BWRs only.

Possible Solution

A possible solution was based on the corrective actions implemented at Pilgrim 1 and involved installing a redundant ATWS trip signal that would interrupt current to the recirculation pumps. Specifically, a new trip coil initiated by an ATWS signal was installed in each recirculation pump motor-generator set drive motor. During an ATWS event, both the recirculation pump field breaker and the motor-generator set supply breaker would receive trip signals, if either high vessel pressure or low reactor water level was reached. Thus, the reliability of the RPT system would be increased and the potential for reaching an unacceptable suppression pool temperature during an ATWS event would be diminished.

PRIORITY DETERMINATION

Frequency Estimate

Several designs are used in accomplishing the RPT function; however, the GE AKF-25 breaker is used primarily in BWR/3 and BWR/4 designs. There were 6 BWR/3 and 19 BWR/4 plants affected by this issue with average remaining lives of 15.4 and 30 years, respectively. Pilgrim 1 (BWR/3) was excluded as an affected plant because it had already implemented the proposed solution.

The issue affected a plant's ability to render the reactor subcritical following an ATWS event. Since the reactor subcriticality analysis[64] of Grand Gulf 1 (BWR/6) is analogous to the WASH-1400[16] analysis of Peach Bottom (BWR/3), the Grand Gulf 1 analysis was used to quantify the influence of the solution on accident frequency and consequence. Thus, the accident sequence affected by this issue was a scram followed by a failure to render the reactor subcritical and was depicted as $T_{23}C$; the transient-initiating event (T_{23}) had a frequency of 7 events/RY.[64]

Failure of reactor subcriticality (Event C) has been probabilistically modelled as the product of the following: (1) failure of the RPS; and (2) failure of the RPT or failure of the operator to take the appropriate actions to shut down the reactor, given RPS failure.[64] From WASH-1400,[16] the failure rate of the RPS was given as 7.7×10^{-6}/demand. The operator error, which was estimated to be 0.1, dominated Item 2 above. The RPT circuit breaker failure rate was given as 3×10^{-3}/demand.

To derive the base case value for event C, the RPT failure rate was modified to 5×10^{-2}/demand, which reflected the lower reliability of the GE AKF-25 circuit breaker.[1328] Therefore, the base case value for event C was approximately $(7.7 \times 10^{-6})[0.1 + (5 \times 10^{-2})]$/demand or 1.16×10^{-6}/demand.

Installation of a redundant ATWS RPT signal was assumed for the adjusted case value of Event C. Therefore, the event (recirculation pump fails to trip) required failure of both RPT subsystems. Assuming that the RPT subsystems are independent and using the GE AKF-25 circuit breaker reliability value, the RPT failure frequency was $(5 \times 10^{-2})(5 \times 10^{-2})$/demand or 2.5×10^{-3}/demand. This value did not take credit for potential increases in reliability that could result from improved test and maintenance programs, or from changing to a more reliable RPT circuit breaker. The estimate also did not consider the potential decrease in RPT system reliability due to common cause failure mechanisms. Thus, the adjusted case value of Event C was about $(7.7 \times 10^{-6})[0.1 + (2.5 \times 10^{-3})]$/demand or 7.9×10^{-7}/demand.

Therefore, the $T_{23}C$ accident sequence frequency was 8.1×10^{-6}/RY for the base case and 5.5×10^{-6}/RY for the adjusted case. The total reduction in accident frequency was 2.6×10^{-6}/RY.

Consequence Estimate

Accident sequence $T_{23}C$ falls into the BWR-2 release category (7.1×10^{6} man-rem/event).[64] The total public dose associated with the base case and adjusted case was 57.4 man-rem/RY and 39.2 man-rem/RY, respectively. Thus, the estimated public dose reduction from implementing the possible solution was 18.2 man-rem/RY

and the total risk reduction for 25 reactors with an average remaining life of 26.5 years was 12,000 man-rem.

Cost Estimate

Industry Cost: The cost to implement the possible solution would vary from plant to plant. The following Pilgrim 1 actual costs were used to estimate the industry cost: (1) engineering = $390,000; (2) labor = $66,000; (3) hardware = $10,000. Thus, the implementation cost was estimated to be about $466,000/plant for a total industry cost of about $11M (excluding Pilgrim).

It was expected that the installed redundant RPT subsystem would only be operated for testing purposes and operation costs were thus negligible. In addition, the testing and maintenance procedures for the redundant RPT subsystem would be very similar to existing RPT subsystems and, therefore, should require very little additional development time. Thus, testing and maintenance were each estimated to require 0.5 man-week/RY, resulting in a plant cost of $2,270/RY and a total industry cost of about $1.5M. Thus, the total industry implementation, operation, and maintenance cost was $12.5M.

NRC Cost: Development of the solution was estimated to require one man-year of contractor labor, at a cost of $100,000/man-year, to complete an evaluation of the solution and any potential alternatives (e.g., enhanced test/maintenance or replacing the degraded RPT breakers with more reliable models). This study would also need to include a preliminary review of plant designs to determine the technical feasibility of the proposed modifications. Development of the solution would also include issuing an NRC generic letter to the affected plants, which was estimated to cost about $11,000.[961]

Review of the proposed plant modifications was estimated to take 5 man-weeks/plant for a total NRC review cost of $280,000 for the 25 affected plants. Thus, the total NRC cost for development and review was $390,000.

Total Cost: The total industry and NRC cost associated with the possible solution was approximately $13M.

Value/Impact Assessment

Based on an estimated public risk reduction of 12,000 man-rem and a cost of $13M associated with the possible solution, the value/impact score was given by:

$$S = \frac{12{,}000 \text{ man-rem}}{\$13M}$$

$$= 923 \text{ man-rem/\$M}$$

Other Considerations

The scram frequency estimate used in the above calculations was considerably greater than that reflected in performance indicator reports published prior to the above evaluation which was completed in August 1991. In addition, the RPS failure rate was originally developed for WASH-1400[16] prior to the ATWS rulemaking and was also quite outdated. As a result, the RPS reliability goal from the ATWS rulemaking proceedings was utilized as a conservative value and the

risk reduction calculations were repeated using: (1) a scram frequency of 3.1/RY, derived from data in the 1988 AEOD Annual Report and Part 1 of the Third Quarter 1990 AEOD report, "Performance Indicators for Operating Commercial Nuclear Power Reactors"; and (2) an RPS failure rate of 3×10^{-5}/demand from the ATWS rulemaking proceeding.[704] These estimates resulted in a potential risk reduction of 20,800 man-rem and a value/impact score of 1,600 man-rem/$M.

CONCLUSION

Based on the potential public risk reduction associated with the possible solution and the other considerations above, the issue was given a medium priority ranking (See Appendix C) and resolution was pursued.

Following identification of this issue, NRC Information Notice No. 92-06[1453] was issued to alert licensees to the importance of maintaining the reliability of equipment required by regulations but not addressed in plant TS. In resolving the issue, the staff conducted a more detailed calculation of the risk reduction potential and concluded that the issue posed a low risk. Thus, the issue was RESOLVED and no new requirements were established.[1439] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

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1328. AEOD/E804, "Reliability of Non-Safety Related Field Breakers During ATWS Events," Office for Analysis and Evaluation of Operational Data, U.S. Nuclear Regulatory Commission, July 26, 1988.

1329. Memorandum for T. King from K. Kniel, "Request for Prioritization of New Generic Safety Issue 'Reliability of Recirculation Pump Trip (RPT) During an ATWS,'" March 17, 1989.

1439. Memorandum for J. Taylor from E. Beckjord, "Resolution of Generic Issue 151, 'Reliability of ATWS Recirculation Pump Trip in BWRs,'" September 29, 1992.

1453. NRC Information Notice 92-06, "Reliability of ATWS Mitigation System and Other NRC Required Equipment Not Controlled by Plant Technical Specifications," January 15, 1992.

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ISSUE 152: DESIGN BASIS FOR VALVES THAT MIGHT BE SUBJECTED TO SIGNIFICANT BLOWDOWN LOADS

DESCRIPTION

Historical Background

This issue was identified[1416] by DSIR/RES following ACRS concerns raised during the review of the resolution of Issue 87, "Failure of HPCI Steam Line Without Isolation," which addressed the design bases for those MOVs that isolate the HPCI, RCIC, and RWCU systems in BWRs. These design bases required that the MOVs close against loads imposed by a double-ended pipe break at design basis flow conditions.

In resolving Issue 87, the staff issued Generic Letter No. 89-10[1217] which required licensees to identify safety-related valves that might not perform adequately under design basis conditions. However, the ACRS believed that the design basis for the HPCI steam line valves and other valves in some plants might not specify the type of heavy duty. Thus, it was possible that heavy duty loads might not be considered for these valves by licensees in response to Generic Letter No. 89-10.[1217] The ACRS recommended that the staff amend the generic letter to require licensees to examine their design bases to determine if safety-related valves, including but not limited to MOVs, were capable of operating against blowdown loads that might not have been considered (by licensees) in their original designs.

Safety Significance

The inability of valves that might be subjected to significant blowdown loads to meet their design bases is a compliance concern. Therefore, the safety significance of this issue lies in the environmental conditions that could result from the inability of containment isolation valves to close under accident conditions. The resulting environmental conditions could cause the malfunction of equipment required to cool the reactor. This issue affects all operating and future plants.

Possible Solution

A possible solution to this issue would include the following: (1) amendment of Generic Letter No. 89-10[1217] to ensure complete compliance with the original design bases; (2) licensee review of design bases for compliance; (3) licensee analyses to assess operability of valves; and (4) hardware modification of isolation valves and additional licensee analyses to bring the valves into compliance with the original design bases.

PRIORITY DETERMINATION

Assumptions

It was assumed that 50% of all 112 operating plants will find that they are in compliance with the amended generic letter. Of the remaining 50% that will have

to perform analyses, 80% will demonstrate compliance. Thus, only 10% of all operating plants will make hardware modifications and perform additional analyses to comply with the amended generic letter. Therefore, the potential exists for a reduction in public risk and occupational dose at approximately 11 plants: 7 PWRs and 4 BWRs. Future plants would not require any modifications since their design would be based on the requirements of the amended generic letter. Oconee 3 and Grand Gulf 1 were selected as the representative PWR and BWR, respectively.

Frequency Estimate

For PWRs, a steam line break was assumed to correspond to an S_3 LOCA. If this LOCA is not isolated, the potential exists for introducing a harsh environment into the containment which may affect the operation of certain components needed to mitigate the LOCA. These components were assumed to be MOVs and pumps, specifically for failure modes designated as hardware or control circuitry, found in accident sequences initiated by an S_3 LOCA.

It was assumed[64] that the potential for increased failure under harsh environmental conditions was not factored into the failure probabilities of the affected parameters in the original plant evaluations. Therefore, the base case failure probabilities were assumed to be 10% higher than their original values. For Oconee 3, this resulted in a base case core-melt frequency of 1.18×10^{-6} /RY.[64]

For BWRs, a steam line break was assumed to correspond to an S LOCA. Assuming the same accident scenario and resultant effects described above for PWRs, the base case core-melt frequency for Grand Gulf 1 was estimated[64] to be 2.48×10^{-7}/RY.

It was assumed that resolution of the issue would return the failure probabilities to their original values in both PWRs and BWRs; this represented a 10% reduction in the base case values. Thus, the adjusted case core-melt frequencies were estimated to be 1.01×10^{-6}/RY and 2.09×10^{-7} for Oconee 3 and Grand Gulf 1, respectively. The potential core-melt frequency reduction associated with the possible solution was calculated to be 1.7×10^{-7}/RY and 3.9×10^{-8}/RY for the affected PWRs and BWRs, respectively.

Consequence Estimate

The affected release categories for Oconee 3 were PWR-2, -3, -4, -5, -6, and -7 and the base case and adjusted case public risk were estimated to be 3.14 man-rem/RY and 2.68 man-rem/RY, respectively, with a potential reduction of 0.46 man-rem/RY. For the 7 affected PWRS with an average remaining life of 25.8 years, the public risk reduction was estimated to be (0.46)(7)(25.8) man-rem or 83 man-rem.

Affected release categories for Grand Gulf 1 were BWR-1 and -2 and the base case and adjusted case public risk were estimated to be 1.76 man-rem/RY and 1.48 man-rem/RY, respectively, with a potential reduction of 0.28 man-rem/RY. For the 4 affected BWRs with an average remaining life of 24.1 years, the estimated public risk reduction was (0.28)(4)(24.1) man-rem or 27 man-rem.

Therefore, the total public risk reduction associated with the possible solution was estimated to be 110 man-rem.[64]

Cost Estimate

Industry Cost: The review of design bases was estimated to require 6 man-weeks/plant at all 112 operating plants affected by the amended generic letter. At $2,270/man-week, this cost was estimated to be $1.525M.

Additional analyses at 56 plants (50% of all affected plants) were estimated to require 12 man-weeks/plant for a total cost of $1.525M. Equipment costs were estimated to be $20,000/plant (10% of all affected plants) that will have to make valve modifications. These modifications were estimated to require 8 man-weeks of skilled labor and 16 man-weeks for additional engineering analyses. Thus, the total estimated cost for 11 plants that require modifications was $0.82M and the total industry cost associated with the possible solution was $3.87M.

NRC Cost: It was estimated that 8 man-weeks would be required to amend Generic Letter No. 89-10[1217] at a cost of $18,000. Review of licensee responses from all 112 plants was estimated to require 2 man-weeks/plant. Responding to the half of these plants that would have to submit analyses was estimated to require 6 man-weeks/plant. For the 11 plants that would have to be modified, NRC review of the additional analyses was estimated to require 12 man-weeks/plant. Thus, the total NRC review time was estimated to be 692 man-weeks. At $2,270 man-week, this translated to a cost of $1.57M.

Total Cost: The total industry and NRC cost associated with the possible solution was $(3.87 + 1.57)M or $5.44M.

Value/Impact Assessment

Based on a potential public risk reduction of 110 man-rem and an estimated cost of $5.44M for a possible solution, the value/impact score was given by:

$$S = \frac{110 \text{ man-rem}}{\$5.44M}$$

$$\sim 20 \text{ man-rem/\$M}$$

CONCLUSION

Based on the potential public risk reduction, this issue was given a LOW priority ranking (See Appendix C). Additional concerns raised[1509] by the ACRS on the ability of safety-related MOVs to close under pipe break conditions were addressed[1510] by the staff but did not affect the priority ranking of the issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1217. NRC Letter to All Licensees of Operating Power Plants and Holders of Construction Permits for Nuclear Power Plants, "Safety-Related Motor-Operated Valve Testing and Surveillance (Generic Letter No. 89-10) - 10 CFR 50.54(f)," June 28, 1989, (Supplement 1) June 13, 1990, (Supplement 2) August 3, 1990, (Supplement 3) October 25, 1990, (Supplement 4) February 12, 1992.

1416. Memorandum for B. Morris from W. Minners, "Prioritization of Proposed New Generic Issue," December 4, 1989.

1509. Letter to J. Taylor from P. Shewmon, "Prioritization of Generic Issue 152, 'Design Basis for Valves that Might Be Subjected to Significant Blowdown Loads,'" April 23, 1993.

1510. Letter to J. Wilkins (ACRS) from J. Taylor(EDO), June 8, 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 154: ADEQUACY OF EMERGENCY AND ESSENTIAL LIGHTING

DESCRIPTION

Historical Background

This issue arose as the result of an event at the Palo Verde Nuclear Generating Station (PVNGS) Unit 3 in which inadequate lighting conditions exacerbated an unrelated reactor trip.[1468] During this event, half of the steam bypass control system malfunctioned, the ADVs failed to operate from both the control room and the remote shutdown panel, and both the normal and the emergency lighting for the main steam support structure failed where the ADVs are located.

One of the principal functions of backup lighting systems at nuclear power plants is the provision of sufficient illumination at the instruments and controls needed by the operators to bring the reactor to a safe (usually shutdown) condition following a plant transient or accident, if normal lighting systems should fail. Due to the necessity of reading posted instructions (and locating and operating controls) while relying only on hand-held flashlights for illumination, initiation of plant depressurization and cooldown through use of the ADVs was delayed at PVNGS-3.[1468]

Safety Significance

During the interval the operators were attempting to open the ADVs, the plant was in a stable, steady-state condition with feedwater supplied to the steam generators by the AFW pumps and steam removed from the steam generators to the atmosphere through the secondary system safety valves. The plant could have been sustained in that stable condition for as long as water could be supplied to the AFW pumps. That safe time period would have been a minimum of several hours but more likely would have been several days, considering the small amounts of water needed (in comparison to that needed during power operation) and the multiple backup sources of water that were available. Thus, the plant was in no imminent danger and could have been maintained in the described stable condition for an indefinite period barring additional equipment failures or operator errors. However, during that time period, the risk from such potential additional failures was greater since the plant was not under full control by the operators; they wanted to (but could not) cool it below the saturation temperature corresponding to the pressure setpoint of the secondary system safety valves.

Possible Solution

The corrective action considered involved NRC development of guidance on appropriate areas to be provided with emergency lighting, adequate illumination levels, and preventive maintenance criteria. Licensees could be required to install additional emergency lighting and upgrade existing lighting systems in compliance with any new requirements that might be developed.

PRIORITY DETERMINATION

Assumptions

It was assumed that 90 PWRs and 44 BWRs with average remaining lives of 28.8 27.4 years, respectively, were affected by this issue. Since emergency and essential lighting failures and their effects were not explicitly addressed in existing PRAs, the method described below was used.[64]

Frequency Estimate

In the Oconee 3 PRA, seven sequences resulted in core damage and involved operator recovery action outside the control room. These seven sequences together accounted for a CDF of 2.54×10^{-5}/RY. It was assumed[64] that the relatively high Human Error Probability (HEP) of 0.1/demand for an operator failing to recover a failed component, used in the Oconee 3 PRA,[889] was appropriate for plants with emergency and essential lighting systems as they existed before any improvements associated with the possible solution. The HEP for the adjusted case following resolution of the issue was assigned a value of 0.003, based on the HEP for selecting an incorrect valve from the control console that is clearly and unambiguously marked.[889] These HEP values were used by PNL[64] to calculate a failure probability for the recovery action P(NR), the probability of an operator either failing to diagnose the appropriate action, P(ND), or failing to perform the recovery action successfully, P(NA).

$$P(NR) = P(ND) + P(NA) - P(ND).P(NA)$$

The probability P(ND) was estimated[64] to be 0.039, assuming 15 minutes are allowed. Since the possible solution does not affect the control room operator's ability to diagnose the need for the recovery action, this parameter is common to both cases, i.e., before and after implementation of the possible solution. The probability P(NA) was derived by constructing a Human Reliability Analysis (HRA) event tree using the techniques described in NUREG/CR-1278[339] that considers the probability that the technician sent into the plant will fail to perform the desired action, and that the control room operator will fail to monitor the feedback on his instrumentation (i.e., the control room operator will fail to detect that the technician has failed to perform the action). The resulting expression is:

$$P(NA) = X_1 + (A \times B) + (C \times D) + (E \times F)$$

where X_1 = Mechanical, physical failure prevents control room operator from getting message to technician (Negligible)

A = Error in message from control room operator to technician (0.001)

B = Control room operator fails to monitor feedback (0.003)

C = Technician fails to understand message from control room operator (0.001)

D = Control room operator fails to monitor feedback (0.003)

E = Technician fails to perform action [this is the previously-discussed HEP] (0.1)

F = Control room operator fails to monitor feedback (0.003)

It was assumed that all the above values remained the same after implementation of the possible solution, except E = 0.003. Thus, the base case and adjusted case values of P(NR) were calculated as follows:

Base Case: $P(NR) = 0.039 + (3.06 \times 10^{-4}) - (0.039)(3.06 \times 10^{-4})$
$= 3.92940 \times 10^{-2}$

Adjusted Case: $P(NR) = 0.039 + (1.5 \times 10^{-5}) - (0.039)(1.5 \times 10^{-5})$
$= 3.90144 \times 10^{-2}$

The ratio of the P(NR) values for the base and adjusted cases was assumed to be approximately equal to the ratio of the CDF values before and after resolution of the issue, i.e., values for the affected sequences involving credit for operator recovery actions outside the control room. Thus, the following ratio was used: $(3.92940 \times 10^{-2})/(3.90144 \times 10^{-2}) = 1.0071666$. Therefore, the change in the affected core-melt frequency was $(1.0071666 - 1)(2.54 \times 10^{-5})$/RY or 1.82×10^{-7}/RY.

Consequence Estimate

For PWRs, the consequence estimate of 207 man-rem/RY associated with the core-melt frequency of 8.2×10^{-5}/RY obtained from the Oconee 3 PRA analysis was used to calculate the potential public risk reduction.[1469] Thus, the public risk reduction was estimated to be $[(207 \text{ man-rem/RY})/(8.2 \times 10^{-5}/\text{RY})][1.82 \times 10^{-7}/\text{RY}]$ or 0.459 man-rem/RY. For BWRs, the scaling relationship developed by PNL[64] showed the public risk reduction to be greater than that for PWRs by a factor of 1.2. Thus, for all 134 affected plants, the total risk reduction associated with the solution to this issue was $(0.459)[(90)(28.8) + (1.2)(44)(27.4)]$ man-rem or 1,854 man-rem.

Cost Estimate

Industry Cost: The cost estimate took into account the implementation of new guidance and/or requirements regarding appropriate areas to be provided with emergency lighting, adequate illumination levels, preventive maintenance criteria, any required installation of additional emergency lighting, and/or upgrading of existing lighting systems to comply with new requirements, if necessary. These activities were estimated[64] to cost $13.37M.

NRC Cost: Development of a solution, support for its implementation, and review of associated operation and maintenance was estimated[64] to cost $5.38M.

Total Cost: The total industry and NRC cost associated with this issue was estimated to be $(13.37 + 5.38)M or $18.75M.

Value/Impact Assessment

Based on a potential public risk reduction of 1,854 man-rem and a cost of $18.75M, the value/impact score was given by:

$$S = \frac{1{,}854 \text{ man-rem}}{\$18.75M}$$

$$= 99 \text{ man-rem/\$M}$$

Other Considerations

(1) All seven events considered in this analysis represented recovery actions performed in the Standby Shutdown Facility (SSF); recovery actions in the remainder of the plant should have some significance. The event[1468] at PVNGS-3 involved just such a recovery action (outside the SSF).

(2) Nuclear plants have multiple redundant safety systems and PRA analyses reflect the very small residual risk from all of them failing at the same time. For example, in the PVNGS-3 event, even given the problems with emergency lighting, the core was not damaged because, while the operators were attempting to open the ADVs without benefit of emergency lighting, the plant was in a stable, steady-state condition with feedwater supplied to the steam generators by the AFW pumps and steam removed from the steam generators to the atmosphere through the secondary system safety valves. The AFW system and steam generator safety valves both have redundancy and their total failure is extremely unlikely. This qualitative argument was quantitatively verified for the PVNGS-3 event by an analysis in NUREG/CR-4674,[1470] Volume 12 (pp. B-420 to B-461). Given occurrence of all of the failures in the PVNGS-3 event, because of the multiple redundancy of the systems that remained operational and would have had to fail in order for core damage to occur, the analysis in NUREG/CR-4674[1470] showed the conditional core damage probability (CCDP) for the event was 4.9×10^{-5}. This compared to a CCDP for a normal reactor trip, with no failures, of approximately 5×10^{-6}. Thus, the PVNGS-3 event was shown by this type of analysis to be no more risky than approximately 10 normal reactor SCRAMs.

(3) This evaluation did not address the risk that might result from possible errors of commission by the auxiliary operators who were sent into the plant with instructions to open the ADVs, i.e., to change the status of the plant. When they arrived in the ADVs area incidentally equipped with a 24" pipe wrench, they found themselves in total darkness, without adequate instructions, confused by their unfamiliarity with the operation they were to carry out, and unable to easily find the posted instructions (and the equipment they were to operate) in the darkness. Their level of stress was not reduced by a nearby safety valve that was periodically opening to relieve pressure in the steam generator; such openings create an unexpected and terrifying loud noise.

CONCLUSION

Much of the problem at PVNGS-3 could have been avoided by better compliance with existing criteria and guidance regarding emergency lighting: 10 CFR 50 Appendix R, Section III.J, "Emergency Lighting"; 10 CFR 50 Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities"; SRP[11] Sections 9.5.1, "Fire Protection Program," and 9.5.3, "Lighting Systems"; and Information Notice 90-69.[1471] Therefore, there was no need to pursue new requirements. Based on the potential public risk reduction, this issue was given

a LOW priority ranking (See Appendix C). In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1468. Memorandum for E. Beckjord from F. Gillespie, "Potential Generic Issue - Adequacy of Emergency and Essential Lighting - (RES Office Letter No. 1, Rev. 1)," September 14, 1990.

1469. NUREG/CR-4834, "Recovery Actions in PRA for the Risk Methods Integration and Evaluation Program (RMIEP)," U.S. Nuclear Regulatory Commission, (Vol. 1) June 1987.

1470. NUREG/CR-4674, "Precursors to Potential Severe Core Damage Accidents," U.S. Nuclear Regulatory Commission, September 1992.

1471. NRC Information Notice No. 90-69, "Adequacy of Emergency and Essential Lighting," U.S. Nuclear Regulatory Commission, October 31, 1990.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 155: GENERIC CONCERNS ARISING FROM TMI-2 CLEANUP

The TMI-2 Safety Advisory Board was established to provide the licensee, General Public Utilities Nuclear Corporation, with a qualified, independent appraisal of the cleanup of TMI-2, with particular emphasis on the assurance of public and worker health and safety. As a result of this appraisal, seven recommendations[1362] were forwarded to the NRC for evaluation. These recommendations were treated as separate generic issues as outlined below.

ISSUE 155.1: MORE REALISTIC SOURCE TERM ASSUMPTIONS

DESCRIPTION

During the TMI-2 accident, fission products did not behave as predicted with the analytical methods and assumptions used in the licensing process at that time and delineated in Regulatory Guides 1.3[213] and 1.4[214] and TID-14844.[73] The earliest expert predictions were that major core damage had occurred. However, the NRC and the licensee believed that core damage was minimal and calculations were redone to confirm this view. Approximately 50% of the core was in a molten state, but there is evidence that only about 55% of the highly volatile fission products and noble gases were released from the reactor vessel with a major portion retained in the reactor building. There is also evidence that less than 5% of the medium and low volatile fission products were released from the reactor vessel.[1362] These observations were based on research conducted since the TMI-2 accident.

It is now generally accepted that the chemical conditions in the reactor vessel were "reducing" in nature as opposed to "oxidizing." The elemental iodine was driven (or converted) to the iodide ion which very readily combined with available metallic ions. The water-soluble character of these chemical forms prevented a major release of iodine to the atmosphere of the containment or auxiliary buildings and only a few Curies were released to the environment. Throughout the TMI-2 accident sequence, the chemical state was maintained such that the water-soluble character was preserved.

With the completion of a large number of PRAs since the TMI-2 event, the Advisory Board believed that it should be possible to list accident sequences with chemical conditions similar to TMI-2. Such a listing could provide a guide as to which accidents might be regarded as hazardous, or less hazardous, relative to the possible escape of iodine and could be useful in the future design of safety features. Since some of the assumptions used for source term considerations at TMI-2 were flawed in this respect, the Board recommended that the source term be restated using current scientific knowledge.[1362]

CONCLUSION

At the time this issue was evaluated in February 1992, comprehensive revisions to 10 CFR Parts 50 and 100 were being pursued by the staff to reflect a better understanding of accident source terms and severe accident insights, as well as evaluate the impact of these phenomena on plant engineered safety features. A replacement for TID-14844[73] was being formulated, based on previous severe

accident research findings, to reflect the existing understanding of fission product release timing, iodine chemistry, and source term magnitude and composition. Thus, a solution to this issue had been identified and the issue was considered nearly-resolved.

In resolving the issue, the staff issued NUREG-1465[1465] which provided more realistic estimates of the fission product source term release into containment, in terms of timing, nuclide types, quantities, and chemical form, given a severe core-melt accident. Thus, the issue was RESOLVED with new requirements for future plants.[1530] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period would not affect the resolution.

ISSUE 155.2: ESTABLISH LICENSING REQUIREMENTS FOR NON-OPERATING FACILITIES

DESCRIPTION

At the time the TMI-2 event occurred, 10 CFR 50 contained regulations primarily for the design, construction, and operation of nuclear facilities but did not provide adequate guidance for the post-accident condition. Much was learned while the unit was being defueled and prepared for the post-defueling, monitored storage phase. The decommissioning rule[1364] issued in 1988 addressed the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits release of the property for unrestricted use and termination of the operating license. The options for compliance with this rule are described in NUREG-0586[173] and include DECON, SAFSTOR, and ENTOMB. Decommissioning activities do not include the removal and disposal of spent fuel; these are considered to be operational activities.

Once a reactor is permanently shut down and defueled, it enters a storage phase until the licensee begins implementation of a decommissioning plan approved by the NRC. During the storage phase, requirements for security plans, operator licensing, emergency planning, etc., that were in effect while the plant was operational, may become unnecessary and burdensome to the licensee. Once all nuclear fuel is removed from the reactor site, the risk of an extraordinary accident, as defined in 10 CFR 50.54(w) and 10 CFR 140.11, is essentially eliminated. The Board recommended that regulatory guidance be developed for use by non-operating and defueled facilities during the storage phase prior to decommissioning.[1362]

CONCLUSION

This issue addressed changes in existing regulatory guidance that could significantly reduce licensee costs without any substantial change in public risk. Thus, it was classified as a Regulatory Impact issue. Revisions to 10 CFR 50.54(w) and 10 CFR 140.11(a)(4) may be necessary to address insurance coverage for non-operating and defueled facilities during the storage phase prior to decommissioning.[1363]

ISSUE 155.3: IMPROVE DESIGN REQUIREMENTS FOR NUCLEAR FACILITIES

DESCRIPTION

The Board recommended[1362] that the NRC undertake an effort to evaluate lessons learned at TMI-2 and incorporate them into the design of future nuclear plants. The recommendations suggested by the Board focused on recovery from a severe accident and were as follows:

(1) Prohibit the use of cinder blocks inside the reactor building (because they absorb so much contamination and become a radiological hazard) or designing the facility to be "robot friendly."

(2) Utilize higher range radiation instrumentation in order to monitor the environment inside the reactor building during a severe reactor accident.

(3) Based on design criteria and clear evidence that the TMI-2 containment building was not challenged, a reduction in criteria might be prudent based upon actual accident conditions. The NRC had reviewed in some detail the capability of reactor containment structures to withstand accident environments, including significant pressure increases; a review of these studies might be helpful and may lead to a reduction in design criteria. A similar effort for reactor vessels has not been undertaken and should be, considering the condition of the lower head of the TMI-2 reactor vessel with the severity of the accident.

(4) TMI-2 has also demonstrated the need to provide access to the underside of a reactor vessel for remote inspections to determine the extent of possible damage in the aftermath of a severe reactor accident. The 52 instrument penetrations in the lower head of the TMI-2 reactor vessel have been a concern since the discovery of once-molten material on the lower head of the reactor vessel and thus lower head integrity has been a major concern during the recovery efforts. For future reactor vessel design, it was recommended that in-core instrumentation penetrate the head instead of the bottom.

PRIORITY DETERMINATION

The four concerns outlined in this issue were evaluated separately below:

(1) In accordance with 10 CFR 50, Appendix I, nuclear power plants are required to keep occupational risk exposure (ORE) as low as is reasonably achievable (ALARA). Cinder blocks constitute one of the materials that are used inside the reactor building of some operating plants as local shielding to meet this ALARA criterion. Prohibiting the use of cinder blocks inside the reactor building would have no impact on public risk in the event of a severe accident. The use of other shielding materials that do not absorb as much contamination has the potential for decreasing the decontamination time (and ORE) following a severe accident.

Designing future nuclear plants to be robot-friendly will require spatial considerations for the mobility of robots that could drastically increase design, engineering, and construction costs. However, as is the case above, the use of robots would have no impact on public risk in the event of a severe accident; only occupational risk would be affected.

From NUREG/CR-2800,[64] the occupational dose from cleanup, repair, and refurbishment following a severe accident was estimated to be 19,860 man-rem. Even assuming that 50% of this dose can be reduced with either the elimination of cinder blocks or the use of a robot for cleanup and assuming a core-melt frequency of 10^{-5}/RY and an average remaining reactor life of 28 years, the potential dose reduction is approximately 3 man-rem/reactor. Thus, this concern had negligible risk reduction potential and consideration of costs would only lower its priority ranking.

(2) The recommendation to utilize higher range radiation instrumentation in order to monitor the environment inside the reactor building during a severe accident was addressed by TMI Action Plan Item II.F.1. This item was clarified in NUREG-0737[98] and required implementation at all plants. Thus, this concern was previously addressed by the staff.

(3) For future plants, the Commission's Severe Accident Policy Statement established the criteria and procedural steps under which new designs for nuclear power plants could be acceptable for meeting severe accident concerns. Rather than a reduction of criteria, it is expected that future plants would have to achieve a higher standard of severe accident safety performance, including clarification of containment performance. The staff's plan of action in this area was presented to the Commission in SECY-92-292.[1427] Operating plants were assessed under the Containment Performance Improvement Program (see Issue 157).

The mode of vessel failure, including investigation of the TMI-2 vessel, was being pursued by the staff as part of its severe accident research program.[1382] The results of this research was expected to determine whether changes to future vessel design would be warranted. Thus, this concern was being addressed by the staff.

(4) The relocation of in-core instrumentation was expected to be addressed by NSSS vendors in the design of future plants which was subject to review and approval by the staff. For example, the bottom-mounted instrumentation penetrations were eliminated in the Westinghouse AP600 design to reduce building volume and costs significantly. Thus, this concern was being addressed by the staff.

CONCLUSION

Of the four recommendations contained in this issue, two were addressed in other ongoing programs and one had been previously addressed by the staff. The remaining recommendation had negligible risk reduction potential and, therefore, was not considered to be safety-significant. Thus, this issue was DROPPED from

further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 155.4: IMPROVE CRITICALITY CALCULATIONS

DESCRIPTION

The Board believed that doubts still remained as to whether the TMI-2 core became critical, or was very close to critical, during the TMI-2 accident and recommended that the NRC establish guidelines that deal with criticality following a severe reactor accident.[1362] These guidelines should take into account abnormal geometries and possible core conditions that could result from the accident. The Board believed that the accident scenario developed by the TMI-2 licensee was sufficiently detailed that a series of geometric configurations could be simulated for criticality calculations. Variables that could be estimated reasonably well included the presence of water, oxidation of cladding, melting and movement of fuel, melting of poison rods, and movement of poison.

CONCLUSION

The safety concern was addressed by DSR/RES in SARP Task 4.3: Investigate the Possibility and Consequences of Recriticality in Degraded BWR Cores.[1382] The staff's study was documented in NUREG/CR-5653[1379] in which it was concluded that there was the potential for recriticality in BWRs, if core reflood occurs after control blade melting has begun but prior to significant fuel rod melting. However, a recriticality event would most likely not generate a pressure pulse significant enough to fail the vessel. Two strategies were identified that would aid in regaining control of the reactor and terminate the recriticality event before containment failure pressures are reached: (1) initiation of boron injection at or before the time of core reflood, if the potential for control blade melting exists; and (2) initiation of RHR suppression pool cooling to remove the heat load generated by the recriticality event and extend the time available for boration.

The issue was not considered to be a major concern for PWRs because of their design that includes a safety injection system for supplying borated water to the core. Furthermore, it was concluded in NUREG/CR-5856[1417] that, during a severe accident, an unmoderated recriticality of the molten, consolidated portion of a degrading core cannot occur at U_{235} enrichments characteristic of a PWR. Based on the staff's efforts in addressing the safety concerns in the SARP, this issue was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 155.5: MORE REALISTIC SEVERE REACTOR ACCIDENT SCENARIO

DESCRIPTION

The TMI-2 event was a severe accident in which approximately 50% of the core was in a molten state at some point during the accident. Approximately 20 tons of the once-molten debris poured through the core support structure into the

water-filled lower plenum and onto the lower head of the reactor vessel. Most codes in use at that time would have predicted a failure of the lower head under these conditions. The severity of the accident showed that the reactor vessel was more difficult to fail than was anticipated.

The Board recommended that in-vessel core-melt progression for severe accidents be studied further by the NRC and that the results be incorporated into existing codes and standards. The Board believed that codes should have the capability to reproduce the TMI-2 accident with reasonable accuracy before they can be accepted as predictive tools.[1362]

CONCLUSION

At the time this issue was evaluated in June 1992, the safety concern was being addressed by DSR/RES in SARP Issue L2: In-Vessel Core Melt Progression and Hydrogen Generation.[1382] In considering core-melt progression, the staff was expected to treat BWRs and PWRs separately because of their different fuel assembly, control element, and lower plenum structures. Concerns common to both BWRs and PWRs are: (1) the integrity of core structures; (2) the mode of core material relocation; (3) hydrogen generation; (4) the mode of bottom head failure; and (5) the effects of water injection. The answers to the above concerns will be different because of the physical differences of BWRs and PWRs. TMI-2 data and the results of new experiments and model development were to be examined by the staff in its research. Based on the staff's efforts on SARP Issue L2, Issue 155.5 was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 155.6: IMPROVE DECONTAMINATION REGULATIONS

DESCRIPTION

The Board believed that the decontamination techniques used throughout the nuclear industry for small activities were not applicable to large-scale activities and recommended that the NRC use the experience gained from the TMI-2 accident to prepare guidelines for decontamination and decommissioning of nuclear plants.[1362]

CONCLUSION

Traditionally, the NRC has not developed or approved decontamination techniques. Due to the many ways in which decontamination can be accomplished and the rapidly evolving technology in this area, it is not practical or beneficial for the NRC to establish guidelines for decontamination techniques. Rather, the NRC has focused on the development of criteria which set standards for exposure of workers and the public (e.g., 10 CFR 20), the levels of allowable residual contamination, and the handling and disposal of the radioactive waste generated. Efforts at establishing residual contamination criteria applicable to decommissioning were in progress as described below.

In June 1991, the Commission deferred[1412] implementation of the Below Regulatory Concern (BRC) policy but reaffirmed its intentions to carry out its responsibilities to address issues related to waste disposal, consumer products,

recycling of materials, and decontamination and decommissioning, as necessary, on a case-by-case basis in the manner in which these issues were considered, prior to the development of the BRC policy statement. In this regard, the staff was directed to continue its accelerated efforts in completing the technical basis for rulemaking on residual contamination criteria.

In accordance with SECY-92-045,[1413] the staff proceeded with an enhanced participative rulemaking process to develop radiological criteria for decommissioning; this effort was tracked in the NRC Regulatory Agenda (NUREG-0936). Based on the above considerations, Issue 155.6 was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 155.7: IMPROVE DECOMMISSIONING REGULATIONS

DESCRIPTION

The Board raised concerns over the requirements for the disposal of highly contaminated components from a nuclear plant during decommissioning and recommended that regulations be developed.[1362]

CONCLUSION

The TMI-2 experience was considered by the staff in the development of the decommissioning rule[1364] in 1988. Industry options for complying with this rule are described in NUREG-0586[173] and include DECON, SAFSTOR, and ENTOMB. As part of its resolution of Issue B-64, "Decommissioning of Reactors," the staff is currently developing an SRP[11] Section for use in its review of licensee decommissioning plans. Concurrent with this effort is the development of two Regulatory Guides: DG-1005, "Standard Format and Content for Decommissioning Plans for Nuclear Reactors"; and DG-1006, "Records Important for Decommissioning of Nuclear Reactors." Thus, Issue 155.7 was DROPPED from further consideration as a new and separate issue. The related concern of decommissioning prematurely shutdown plants was addressed in Issue 155.2. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

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1382. NUREG-1365, "Revised Severe Accident Research Program Plan," U.S. Nuclear Regulatory Commission, August 1989, (Rev. 1) December 1992.

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1413. SECY-92-045, "Enhanced Participatory Rulemaking Process," February 7, 1992.

1417. NUREG/CR-5856, "Identification and Evaluation of PWR In-Vessel Severe Accident Management Strategies," U.S. Nuclear Regulatory Commission, March 1992.

1427. SECY-92-392, "Advance Notice of Proposed Rulemaking on Severe Accident Plant Performance Criteria for Future LWRs," August 21, 1992.

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ISSUE 156: SYSTEMATIC EVALUATION PROGRAM

In 1977, the NRC initiated the Systematic Evaluation Program (SEP) to review the designs of 51 older, operating nuclear power plants. The SEP was divided into 2 phases. In Phase I, the staff defined 137 issues for which regulatory requirements had changed enough over time to warrant an evaluation of those plants licensed before the issuance of the SRP.[11] In Phase II, the staff compared the design of 10 of the 51 older plants to the SRP[11] issued in 1975. Based on these reviews, the staff identified 27 of the original 137 issues that required some corrective action at one or more of the 10 plants that were reviewed. The staff referred to the issues on this smaller list as the SEP "lessons learned" issues and concluded that they would generally apply to operating plants that received operating licenses before the SRP[11] was issued in 1975.

In SECY-84-133,[814] the staff presented the 27 SEP issues to the Commission as part of a proposal for an ISAP, the intent of which was to review safety issues for a specific plant in an integrated manner. Two SEP plants participated in the ISAP pilot efforts. Following the review of these two pilot plants, ISAP was discontinued.

In SECY-90-160,[1443] the staff forwarded for Commission approval a proposed license renewal rule and supporting regulatory documents. In this paper, the staff stated that certain unresolved safety issues could weaken the generic justification of the adequacy of the current licensing bases argument. These issues included SEP topics for 41 older plants that had not been explicitly reviewed under Phase II of the SEP. The Commission requested that the staff keep it informed of the status of the program to determine how the SEP "lessons learned" issues had been factored into the licensing bases of operating plants.

Resolution of the 27 SEP issues was deemed by the staff to be important to the development of the license renewal rulemaking. The key regulatory principle underlying the license renewal rule is that the current licensing bases (CLBs) at all operating nuclear power plants, with the exception of age-related degradation, provide adequate protection to the public health and safety. This principle is reflected in the provisions of the license renewal rule which limit the renewal decision to whether age-related degradation has been adequately addressed to assure continued compliance with a plant's CLB. In order to adopt this approach, the NRC must be able to provide a technical basis for the key principle of license renewal. Accordingly, the rulemaking included a technical discussion documenting the adequacy of the CLB for all nuclear power plants, in both the statement of considerations and in NUREG-1412.[1444] However, as discussed in SECY-90-160,[1443] the staff identified a potential weakness in the discussion of the adequacy of the CLB with regard to the 41 older, non-SEP plants. To address this potential weakness, the staff undertook an effort to determine whether or not each SEP issue either had been or was being addressed by other regulatory programs and activities.

The staff completed this effort and placed each SEP issue into one of the following categories: (1) issues that had been completely resolved (i.e., necessary corrective actions had been identified by the staff, transmitted to licensees, and implemented by licensees); (2) issues that were of such low safety

significance so as to require no further regulatory action; (3) issues that were unresolved, but for which the staff had identified existing regulatory programs that cover the scope of the technical concerns and whose implementation would resolve the specific SEP issue, such as the Individual Plant Examination (IPE) and the Individual Plant Examination of External Events (IPEEE); and (4) issues that were unresolved and regulatory actions to resolve the issues had not been identified. The 27 SEP issues and applicable regulatory programs were summarized and presented in SECY-90-343.[1351] The staff concluded that the 22 SEP issues in Categories 3 and 4 remained unresolved for purposes of justifying the adequacy of the CLB for some portion of the 41 older, non-SEP plants. The following is an evaluation of these 22 issues: nineteen from Category 3 and three from Category 4.

ISSUE 156.1.1: SETTLEMENT OF FOUNDATIONS AND BURIED EQUIPMENT

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The objective of this issue was to ensure that safety-related structures, systems, and components were adequately protected against excessive settlement. The scope included the review of subsurface materials (soils or geologic) and foundations to assess the potential static and seismically-induced settlement of all safety-related structures and buried equipment.

Excessive settlement or collapse of foundations and buried equipment for structures, systems, and components under either static or seismic loading could result in failure of structures, interconnecting piping, control systems or cables, or other equipment (tanks, etc.) such that the capability to safely shut down a plant, or mitigate the consequences of an accident, could be compromised.

There are two specific concerns in this issue: (1) the potential impact of static soil settlements on foundations and buried equipment where the soil may not have been properly prepared; and (2) seismically-induced differential settlement and potential soil liquefaction following a postulated seismic event. These two concerns are limited only to plants that have soil-supported, safety-related structures (including vertical, field-erected tanks) and soil-buried piping and components (including tanks) that have the potential for excessive settlement but were not reviewed to the pertinent SRP[11] Sections 2.5.4 and 2.5.5.

For the 41 older, non-SEP plants with OLs issued before 1975, any impact of static settlement on structural foundations (including the foundations of buried components) should become noticeable in the first 5 to 10 years. Thus, any significant settlement would have been revealed already and warranted corrective action. In addition, the ongoing IPEEE program[1354] has elements in its seismic task which requires that, for plants on soil sites, potential seismically-induced settlement and soil liquefaction should be assessed during its implementation.

CONCLUSION

This issue is being addressed by the SRP[11] for future plants as well as for operating plants with OLs issued after 1975. For the 51 older, operating plants, this issue was considered resolved for the 10 SEP plants. For the remaining 41 non-SEP, operating plants, any significant static settlement would have been

revealed already and warranted corrective action. The concern on the seismically-induced settlement and soil liquefaction for these 41 older, non-SEP operating plants will be addressed during the implementation of the IPEEE Program. Therefore, Issue 156.1.1 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.1.2: DAM INTEGRITY AND SITE FLOODING

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The safety concern was the ability of a dam to prevent site flooding and ensure a cooling water supply. The safety features of a dam would normally include remaining stable under all conditions of reservoir operation, controlling seepage to prevent excessive uplifting water pressure or erosion of soil materials, and providing sufficient freeboard and outlet capacity to prevent overtopping. The objective of this issue was to ensure that adequate margins of safety are available under all loading conditions and uncontrolled releases of retained water are prevented. Plants must provide the basis for ensuring that all safety-related structures, systems, and components are adequately protected against flooding that might result from dam failures. Further, review of licensee procedures would determine whether an adequate supply of cooling water exists in the ultimate heat sink during normal and emergency operations. The 41 non-SEP plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

If a dam exists in the vicinity of a nuclear power plant, it will have to meet one of the following criteria:

(1) If the dam provides impoundment for an UHS at a plant or provides flood protection, the dam is an essential part of the plant and the safety of the dam needs to be ensured throughout the life of the plant. The dam has to be designed and remain stable under both static and seismic conditions.[688,916]

(2) If the dam provides impoundment only for plant operation, but not as a part of the UHS, there are no regulatory requirements for dam design. However, the flood conditions that could be caused by dam failures should be considered in establishing the design basis flood.[687] When upstream dams or other features that provide flood protection are present, in addition to the analyses of the most severe floods that may be induced by either hydrometeorological or seismic mechanisms, reasonable combinations of less severe flood conditions and seismic events should be considered in establishing the design basis flood.

The IPEEE Program will address the safety and the flooding effects of dams. Under this program, the safety of dams will be assessed by all licensees in the process of searching for severe accident vulnerabilities due to external events.[1222,1354] If the failure of these dams would have significant consequences, i.e., a breach of an UHS which might lead to a severe accident, they would have to be evaluated and inspected to assess their existing condition and vulnerability to earthquakes. If the failure of an upstream dam could lead to significant flooding

at a site, i.e., the postulated flood exceeded the design basis flood and might lead to a severe accident, the effect of flooding will have to be addressed in the IPEEE.

CONCLUSION

The safety concerns of dam integrity and site flooding will be addressed in the implementation of the IPEEE Program at the 41 plants affected by this issue.[1575] Therefore, Issue 156.1.2 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.1.3: SITE HYDROLOGY AND ABILITY TO WITHSTAND FLOODS

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The concerns of this issue included identifying the site hydrologic characteristics, the capability of structures important to safety to withstand flooding, the determination of the adequacy of the cooling water supply, and the ISI of water control structures. Hydrologic considerations are the interface of the plant with the hydrosphere, the identification of hydrologic causal mechanisms that may require special plant design, or operating limitations with regard to floods, and water supply requirements. The specific items to be reviewed in this issue were:

(1) Hydrologic Description - To ensure that plant design reflects appropriate hydrologic conditions.

(2) Flooding Potential and Protection - To ensure that the plant is adequately protected against floods.

(3) Ultimate Heat Sink - To ensure an appropriate supply of cooling water is available during normal and emergency shutdowns.

(4) ISI of Water Control Structures - To ensure an adequate inspection program is in place to prevent water control structure deterioration or failure which could result in flooding or loss of the UHS.

The 41 non-SEP plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

At a nuclear plant, the safety-related structures, systems, and components, identified in accordance with Regulatory Guide 1.29,[916] must be designed to withstand the conditions resulting from the worst probable site-related flood and retain the capability for shutdown and maintenance.[687] Alternatively, NRC permits licensees not to design against the worst flood conditions for safety-related structures, systems, and components if sufficient warning time is shown to be available to shut down the plant and implement adequate emergency procedures. However, the safety-related structures, systems, and components must be designed to withstand the conditions resulting from a Standard Project Flood (with a flow-rate about 40% to 60% of the PMF).[687]

On June 28, 1991, the NRC requested all licensees to conduct an IPEEE to search for severe accident vulnerabilities due to external events[1222]; external flooding is one of the events that will be addressed in the IPEEE.[1354] All licensees will have to examine the flood designs and associated flood protection measures at their sites to determine if severe accident vulnerabilities due to external floods exist. Therefore, the above Items 1 and 2 have been addressed in the external flood portion of the IPEEE program.

Item 3 is related to maintaining the functioning of the SWS and the DHR system of a plant. The severe accident vulnerability resulting either from failure or unavailability of the UHS is one of the important items to be examined in the IPE and IPEEE programs.

The NRC will require the affected licensees to upgrade their ISI programs for water control structures where inspection findings and any subsequent analyses reveal inadequacies in meeting the intent of Item 4.

CONCLUSION

The safety concerns of site hydrologic characteristics and the capability of plants to withstand flooding will be addressed in the implementation of the IPE and IPEEE Programs at the 41 plants affected by this issue.[1575] Therefore, Issue 156.1.3 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.1.4: INDUSTRIAL HAZARDS

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The objective of this issue was to ensure that the integrity of safety-related structures, components, and systems will not be damaged by potential hazards from nearby transportation, storage, or industrial facilities. Such hazards include: (1) shock waves and thermal flux from nearby explosions of munitions or explosive gases or chemicals; (2) drifting toxic/explosive vapor clouds; (3) aircraft; and (4) missiles that can result from nearby explosions, such as a rocketing chemical tank car. In a few past licensing cases, reactor containment and intake structure hardening and pipeline relocation have been required to ensure safety of the plants. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

Regulatory Guide 4.7[1372] and SRP[11] Sections 2.2.1, 2.2.2, and 2.2.3 have been used since 1975 in the design of nuclear power plants for protection against industrial hazards. In addition, Regulatory Guides 1.78,[1373] 1.91,[1374] and 1.95[1375] were issued to provide further regulatory guidance in this area. Prior to the issuance of these criteria, offsite hazards had been an area of long-standing concern and were reviewed on a case-by-case basis.

Supplement 4 to Generic Letter No. 88-20[1222] required all licensees to conduct an IPEEE to search for severe accident vulnerabilities due to external events. Industrial hazards comprise one of the external events that will be addressed in the IPEEE.[1354]

CONCLUSION

Based on past staff reviews, existing review criteria and guidance, and the implementation of the IPEEE program for all plants, the concern for industrial hazards was adequately addressed. Therefore, Issue 156.1.4 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.1.5: TORNADO MISSILES

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] All plants licensed after 1972 were designed for protection against tornadoes. The concern existed, however, that plants constructed prior to 1972 may not be adequately protected, in particular, those reviewed before 1968 when criteria on tornado protection were first developed. The objective of this issue was to ensure that safety structures, systems, and components can withstand the impact of an appropriate postulated spectrum of tornado-generated missiles. The failure of safety-related structures, systems, or components due to a tornado-induced missile could compromise the ability of a plant to safely shut down. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

A plant must be designed to remain in a safe condition in the event that the most severe tornado that can be reasonably predicted occurs at the plant site as a result of severe meteorological conditions. All safety-related structures, systems, and components must be designed to withstand the effects of the design basis tornado, tornado-generated missiles, and other tornado-induced effects.[42,916]

Under the IPEEE program, all licensees are required to examine their plants to determine if severe accident vulnerabilities due to high winds/tornadoes exist.[1222,1354] The criteria used for plant design (such as the design basis wind speed, parameters of the design basis tornado along with missile spectrum, and the allowable stresses and load combinations) will be examined. The reporting criterion, 10^{-6}/year CDF, specified for the IPEEE, however, is considered to be less stringent compared to the CDF associated with tornado missiles design criteria (a product of combining the probability of exceedance associated with the design basis tornado and the conditional failure probability associated with engineering design and construction against tornado missiles). Therefore, meeting the objectives of the IPEEE does not mean, in this situation, that current NRC guidelines for tornado design have been met. Thus, the staff believes that any vulnerability associated with tornado missiles will be evaluated and reported in the IPEEE submittals.

CONCLUSION

The safety concern for tornado missiles will be addressed in the implementation of the IPEEE Program at the 41 plants affected by this issue. Therefore, Issue 156.1.5 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.1.6: TURBINE MISSILES

DESCRIPTION

This issue is one of the three Category 4 issues identified by NRR in SECY-90-343.[1351] The safety concern was the potential damage from turbine missiles in nuclear plants licensed before 1973.

As a result of turbine disc failures at two nuclear plants and a number of non-nuclear plants prior to 1973, the staff believed that high energy missiles could be generated from steam turbines with the potential for causing failures in safety-related systems. The two areas of concern were: (1) failures at design overspeed because of degraded disc material, poor ISI of flaws, or chemistry conditions leading to SCC; and (2) destructive overspeed failures that would bring into question the reliability of electrical overspeed protection systems, the reliability and testing programs for stop and control valves, and the ISI of valves. For plants licensed after 1973, the safety concerns of this issue were reviewed by the staff as part of its OL activities; turbine overspeed protection designs were found acceptable and the magnitude of the potential damage from turbine missiles was determined to be plant-specific.

CONCLUSION

The safety concerns of this issue were addressed in the evaluation of Issue A-37, which focused primarily on plants licensed prior to November 1976; SRP[11] requirements for turbine design were issued for use by CP applicants after this date. Based on the historical failure rate of turbines used in the evaluation, Issue A-37 was determined to have little safety significance. No new data were provided in SECY-90-343[1351] that changed this conclusion. Therefore, this issue was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.2.1: SEVERE WEATHER EFFECTS ON STRUCTURES

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] Safety-related structures, systems, and components should be designed to function under all severe weather conditions to which they may be exposed. Meteorological phenomena to be considered include straight winds, tornadoes, snow and ice loads, and other phenomena judged to be significant for a particular site. The objective of this issue was to identify those meteorological conditions which should be considered in the structural reviews to determine the ability of structures to withstand conditions such as flooding, wind, tornadoes, hurricanes, tsunamis, and seiches. The dynamic effects of waves, tornado pressure drop loading, and possible in-leakage due to floods were to be considered. The 41 non-SEP plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

A nuclear power plant must be designed to remain in a safe condition in the event that the most severe weather conditions that can reasonably be predicted at the site occurs. All the safety-related structures must be designed to withstand the

effects of the design basis flood, wind, hurricane, tornado, wind/tornado-generated missiles, and other wind/tornado-induced effects.[916]

Under the IPEEE Program, all licensees were requested to examine their plants to determine if severe accident vulnerabilities due to floods or high winds/tornadoes exist.[1222,1354] Licensees were expected to examine their design criteria (such as the design flood level, the hydrostatic pressures against the structures, the design basis wind speed, parameters of the design basis tornado along with missile spectrum, and the allowable stresses and load combinations) used for plant structures to determine if the 1975 SRP[11] criteria are satisfied. If a plant conforms to these criteria, it will be judged that the contribution to CDF from the effects of severe weather is less than 10^{-6}/year and the IPEEE screening criterion would be met. Otherwise, additional evaluation will have to be made to establish severe accident vulnerabilities due to the effects of severe weather. The reporting criterion of 10^{-6}/year CDF specified for the IPEEE will provide a means by which the ability of a nuclear power plant to withstand severe weather conditions can be reviewed and examined for severe weather-induced vulnerabilities.

Snow and ice loads, when accompanied by strong winds, have caused several complete and partial losses of offsite power and the potential of causing severe accidents at a particular site will be evaluated in the IPE program. Snow and ice loads alone, are judged, based on limited PRA experience, to be unlikely to cause significant structural failure that might lead to severe accidents at nuclear power plants.

CONCLUSION

The safety concern of severe weather effects on structures will be addressed in the implementation of the IPEEE program. Therefore, Issue 155.2.1 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.2.2: DESIGN CODES, CRITERIA, AND LOAD COMBINATIONS

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] With the development of nuclear power, provisions addressing nuclear power plants were progressively introduced into codes and standards to which plant buildings and structures are constructed. Because of this evolutionary development, older nuclear power plants conform to a number of different versions of codes and standards, some of which have since undergone considerable revision. There has likewise been a corresponding development of other licensing criteria, resulting in similar non-uniformity in many of the requirements to which plants have been licensed.

Individual SEP plant reviews identified specific areas of structural design code changes for which the previous codes used in the SEP review required greater safety margins than earlier versions of the codes, or for which no original code provision existed. Most plants demonstrated that safety margins in building structures were not significantly lower than those required by the codes and

standards used in the SEP review. A few SEP plants required certain modifications to plant structures.

The concern of this issue was to provide assurance that building structures that house systems and components important to safety are capable of withstanding the effects of natural phenomena such as earthquakes,[916] tornadoes (See Issue 156.1.5), hurricanes, and floods without loss of capability to perform their safety function. These events could cause walls or roofs to collapse damaging equipment that perform a safety function, thereby increasing the likelihood of a transient or LOCA.

CONCLUSION

On June 28, 1991, Supplement 4 to Generic Letter 88-20[1222] was issued requesting all licensees to perform an IPEEE to determine if vulnerabilities to severe accidents initiated by natural phenomena existed.[1354] The as-built structures, systems, and components in conjunction with operating plant conditions will be used to assess the adequacy of plant safety. Although this program does not directly address the effects of specific structural design code changes, it does in part focus on evaluating the capability of building structures to withstand natural phenomena and to search for cost-effective improvements that can be made to either prevent or reduce the impact of severe accidents. Thus, the staff believed that any severe accident vulnerabilities associated with the effects of natura phenomena on building structures will be evaluated and reported in the IPEEE submittals.

The safety concern with respect to the capability of building structures to withstand the effects of natural phenomena will be sufficiently addressed in the implementation of the IPEEE Program at the 53 operating plants (34 PWRs and 19 BWRs) affected by this issue. Therefore, Issue 156.2.2 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.2.3: CONTAINMENT DESIGN AND INSPECTION

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The objective of this issue was to review the inspection program for tendons in prestressed concrete containment structures to determine whether the inspection programs included testing of prestressed tendons, checking for corrosion or relaxation and possible deterioration of prestressed containments, and whether the concrete in the containment dome or walls degraded due to shrinkage or creep. The 41 non-SEP plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

The concerns about the tendons were addressed in Issue 118 which was identified when a dented and leaking tendon grease cap was found during inspection at Farley Unit 2. The generic implications of tendon anchor head failures were studied under Issue 118 and tendon inspection and surveillance programs were developed that could be followed by licensees to mitigate or reduce such problems. The

guidance for inspection and surveillance are contained in Regulatory Guides 1.35[481] and 1.35.1.[1360]

The containment dome or wall degradation due to shrinkage or creep is an age-related factor and is also addressed in Regulatory Guide 1.35.1.[1360] For license renewal applications, this concern was addressed in Draft Regulatory Guide DE-1009, "Standard Format and Content of Technical Information for Applications to Renew Nuclear Power Plant Operating Licenses," which will resolve the concern when issued in final form.

10 CFR 50 Appendix A (GDC 53), as implemented by Regulatory Guide 1.35,[481] requires that measured tendon forces (guidance provided in Regulatory Guide 1.35.1[1360]) be compared with acceptance criteria. This issue was reviewed by the staff for all SEP plants and accepted on a case-by-case basis, as documented in SERs; some of these plants also developed ISI programs.

CONCLUSION

The safety concerns of containment design and inspection at the 41 plants affected by this issue were addressed in the resolution of Issue 118. Beyond the normal life of the plants, the age-related concrete degradation concern will be addressed in the License Renewal Program. Therefore, 156.2.3 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.2.4: SEISMIC DESIGN OF STRUCTURES, SYSTEMS, AND COMPONENTS

DESCRIPTION

This issue is of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The objective of this issue was to review and evaluate the original seismic design (seismic input, analysis methods, design criteria, seismic instrumentation, seismic classification) of safety-related plant structures, systems, and components to ensure the capability of plants to withstand the effects of an earthquake. Further, this issue would verify whether the free field ground motion specified for plant design adequately represents the vibratory ground motion associated with a postulated SSE at each plant. The free field ground motion will be utilized as the input to analyses to verify the design adequacy of structures, piping, and equipment. This review and evaluation will address the SSE only, since it represents the most severe event that must be considered in plant design. The scope of the review includes three major areas: (1) the integrity of the reactor coolant pressure boundary; (2) the integrity of fluid and electrical distribution systems related to safe shutdown; and (3) the integrity of mechanical and electrical equipment and engineered safety features systems (including containment). This issue did not call for a detailed review of all safety-related structures, systems, and components; rather, a sampling approach supported by a set of confirmatory analyses were to be performed. The sample size and confirmatory analyses were to be increased, if necessary. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

GDC 2 of Appendix A to 10 CFR 50 requires that nuclear power plant structures, systems, and components important to safety be designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. An earthquake is one of the natural phenomena whose effects nuclear power plants must be designed to withstand and remain in a safe condition.

In Supplement 4 to Generic Letter No. 88-20,[1222] licensees were required to conduct an IPEEE to search for severe accident vulnerabilities due to external events. A seismic event is one of the external events that should be addressed in the IPEEE.[1371] All licensees will have to review and evaluate the seismic capabilities of their plants (the as-built, as-operated plants) to withstand the earthquake effects well beyond the design basis and to determine if severe accident vulnerabilities due to seismic events exist at their plants. The seismic input has been evaluated by the staff in the Eastern United States Probabilistic Seismic Hazard Program and the results have been factored into the process of determining the seismic review scope in the IPEEE.

The seismic qualification of mechanical and electrical equipment is being resolved by the implementation of the resolution of Issue A-46. A seismic IPEEE can be accomplished by performing either a seismic PRA with enhancements or a seismic evaluation using a seismic margins method with enhancements. The review scope may vary from plant to plant depending on the selected method and the prescribed seismic hazard condition at the site. Even with the minimum effort under the IPEEE seismic program, at least two success paths (a preferred and an alternative) to shut down and maintain a plant in a safe shutdown condition will be evaluated.[1371] This process, when using the seismic margins approach, might not provide a detailed review of all safety-related structures, systems, and components, but it will represent a sampling approach, thus fulfilling the objective of Issue 156.2.4. Furthermore, if warranted as a result of staff review, additional analyses on selected safety-related structures, systems, and components can be performed.

CONCLUSION

The safety concerns for the seismic design of structures, systems, and components will be addressed in the implementation of the IPEEE. Therefore, Issue 156.2.4 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.3.1.1: SHUTDOWN SYSTEMS

DESCRIPTION

Issues 156.3.1.1 and 156.3.1.2 were combined and evaluated together. These issues are two of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by these issues.

Issue 156.3.1.1 addressed the capability of plants to ensure reliable shutdown using safety-grade equipment. Systems and components important to safety should be designed, fabricated, installed, and tested to quality standards commensurate with the safety function to be performed. Also, systems and components that are

required to withstand the effects of an SSE and remain functional should be classified as Seismic Category I. Due to the evolutionary nature of design codes and standards, the staff believed that operating plants may have been designed to requirements that are not as conservative as those currently required. Systems needed to remove decay heat and reach safe shutdown should have sufficient redundancy to ensure that their function can be accomplished with a loss of offsite power and a single failure. Systems needed to shut down must also remain functional following external events. In addition, the plant operating procedures which direct the use of these systems during normal and abnormal events were to be evaluated.

Issue 156.3.1.2 addressed the review of electrical instrumentation and control features of systems required for safe shutdown, including support systems, to determine whether they met existing licensing requirements. This review was to include the capability and methods of bringing the plant from a high pressure to a low pressure cooling condition, assuming the use of only safety equipment.

The intent of these issues have been met by a number of NRC requirements and initiatives that are already in place to secure reliable plant shutdown capability. These are as follows:

(1) The fire protection rule (10 CFR 50, Appendix R) requires that the capability for shutdown be maintained, in the event of a fire in any location;

(2) The station blackout rule (10 CFR 50.63) requires the capability to cope with a complete loss of AC power and maintain safe shutdown at the same time;

(3) A number of initiatives under the TMI Action Plan[48] enhance auxiliary feedwater capability, including emergency power provisions;

(4) Improved capability for natural circulation cooldown was required by Generic Letter No. 81-21[1355] and improved TS that enhance RHR operability in all modes were required by Generic Letter Nos. 80-42 and 80-53[1356];

(5) TMI Action Plan[48] Item I.C.1 requires upgraded procedures for emergency conditions, including alternate means of providing a heat sink;

(6) The TMI Action Plan,[48] as clarified by NUREG-0737,[98] resulted in the issuance of requirements to licensees to implement Regulatory Guide 1.97[55] which specifies instrumentation for monitoring important parameters such as pressure, flow, and temperature (Continuing improvements in emergency procedures and training also address these issues);

(7) The resolution of Issue A-46 and the imposition of Generic Letter Nos. 87-02[1069] and 87-03[1387] required licensees to address the seismic adequacy of equipment needed to bring a plant to hot shutdown and maintain that condition for a minimum of 72 hours;

(8) The resolution of Issue 99 addressed corrective actions to reduce risk during shutdown with requirements issued in Generic Letter No. 88-17.[1145] The program described in this letter was included in a broader program

described in SECY-91-283[1370] to evaluate the risk associated with shutdown and low power.

The resolution of Issue A-45 spanned the period from March 1981 to September 1988 during which time, extensive, PRA-based determinations of the risk resulting from shutdown cooling system failures at 6 representative operating plants were made. These studies included (but were not limited to) the concerns of Issues 156.3.1.1 and 156.3.1.2. The technical resolution of Issue A-45 was described in SECY-88-260[1143] in which the following conclusions were presented:

(1) The risk due to loss of DHR systems could be unduly high for some plants;

(2) DHR failure vulnerabilities and the optimum corrective actions for those vulnerabilities are strongly plant-specific;

(3) Detailed plant-specific analyses under the IPE program, including extension of the IPE program to require consideration of externally-initiated events (anticipated at the time of the resolution of Issue A-45 but since accomplished), will be needed to impose and implement the resolution of this issue.

The staff concluded from the PRA studies that the risk from DHR-related failures might be too high at some plants, but a generic corrective action or a set of actions could not be identified that would both reduce that risk to an acceptable level and be cost-effective at all plants. It was believed, however, that cost-effective plant-specific actions might be possible that would reduce DHR-failure-related risk and it was concluded that the most efficient method to identify any such actions would be through the IPE program.

Appendix 5 of Generic Letter No. 88-20[1222] provided a specific description of those topics addressed in Issue A-45 and related to internally-initiated events (including those raised in Issues 156.3.1.1 and 156.3.1.2) that are to be considered in the IPE program. The IPE process was extended to include externally-initiated events (IPEEE) upon issuance of Supplement 4 to Generic Letter No. 88-20.[1222] Section 5 of this supplement specifically described how the IPEEE program was to be used to implement the technical resolution of those topics in Issue A-45 that are related to externally-initiated events.

The studies performed in the resolution of Issue A-45 included the analysis of events that initiate at full power conditions. Although the final results (total risk resulting from DHR-related failures) were increased by 20% for PWRs and 30% for BWRs to account for risk from DHR-related failures, during events that initiate when a plant is not at full power (such as hot standby and cold shutdown), such events were not investigated in detail. The IPE process was consistent with the analyses completed for Issue A-45 in that it only required consideration of events that initiate at full power conditions.

However, detailed attention is currently being paid to DHR failure-related events that initiate at conditions other than full power by an extensive NRC program initiated with the issuance of Generic Letter No. 88-17[1145] which resulted from an Augmented Inspection Team (AIT) investigation of a 1987 loss-of-DHR event at Diablo Canyon.[1369] This letter required licensees to investigate and, if necessary, improve procedures involving containment isolation and cooling and DHR-related equipment operation methods and training during non-power operations,

when the reactor primary coolant inventory is reduced. This work received additional impetus since the issuance of Generic Letter No. 88-17[1145] by a loss-of-DHR event at the Vogtle nuclear plant. The Vogtle event resulted in the issuance of SECY-91-283[1370] which described all aspects of the extensive program including, but not limited to, the program outlined in Generic Letter No. 88-17.[1145] Some aspects of the program described in SECY-91-283[1370] will contribute to the imposition and implementation of the resolution of Issue A-45. This program now includes the NRC-sponsored Low Power and Shutdown (LP&S) Program which was originally formulated as part of the NRC response to the Chernobyl event.[1195] The LP&S work is being performed by BNL and SNL with additional work regarding seismicallyinitiated events being performed by Future Resources Associates (FRA), Inc. The objectives of the LP&S program were to: (1) assess the frequency and risk of accidents initiated during LP&S modes of operation for two nuclear power plants; (2) compare the assessed frequency and risk with those of accidents initiated during full power operations; and (3) develop new methods for assessing LP&S accident frequency and risk, as necessary.

CONCLUSION

The safety concerns of Issues 156.3.1.1 and 156.3.1.2 were addressed in the resolution of Issue A-45 and in the IPE and IPEEE programs which were supplemented by the Evaluation of Shutdown and Low Power Risk Issues Program described in SECY-91-283.[1370] Therefore, Issues 156.3.1.1 and 156.3.1.2 were DROPPED from further consideration as new and separate issues. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issues.

ISSUE 156.3.1.2: ELECTRICAL INSTRUMENTATION AND CONTROLS

This issue was evaluated with Issue 156.3.1.1 above and DROPPED from further consideration as a new and separate issue.

ISSUE 156.3.2: SERVICE AND COOLING WATER SYSTEMS

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The safety concern was the capability of service and cooling water systems to meet their design objective with adequate margin. This issue was raised to provide assurance that service and cooling water systems are: (1) capable of transferring heat from structures, systems, and components important to safety to the ultimate heat sink; (2) provided with adequate physical separation such that there are no adverse interactions among the systems under any mode of operation; and (3) provided with sufficient cooling water inventory or that adequate provisions for makeup are available. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

Concerns for the potential unavailability of SWS were addressed in Issues 51, 130, and 153. Issue 51 was resolved and implemented at operating plants in accordance with Generic Letter No. 89-13.[1259] The resolution identified a recommended improvement in the reliability of open cycle SWS that could result from reducing the potential for flow blockage in safety-related components caused

by bivalves, sediment, and corrosion products. This improvement was in the form of an integrated, baseline fouling surveillance and control program for all nuclear power plant open cycle SWS.

Issue 130 was resolved and is being implemented at certain specific plants in accordance with Generic Letter 91-13.[1368] This issue addressed the concerns regarding the SWS reliability of 14 PWRs at multi-unit sites with two SWS trains per unit and a crosstie capability. The resolution identified several cost-effective options that were considered for reducing the risk from loss of SWS (due to causes other than fouling), including a backup means of RCP seal cooling plus additional SWS TS and emergency procedures.

Issue 153 affected all LWRs except those that were addressed in Issue 130. All potential causes of SWS unavailability were to be considered, except those that were resolved and implemented in accordance with Generic Letter No. 89-13.[1259] The resolution plan for Issue 153 was divided into two phases: Phase I, a pilot study; and Phase II, a generic evaluation. The results of Phase I were to be used to determine if an interim resolution was viable and how to proceed with Phase II; Issue B-32 was also addressed in the resolution of Issue 153.

Concerns for the availability of cooling water systems were addressed in the resolution of Issue 143. This issue addressed the potential unavailability of chilled water systems which provide room cooling to maintain adequate environmental temperature for non-safety-related and safety-related equipment. The potential loss of room cooling could affect the operability of the safety-related systems including the SWS system.

CONCLUSION

All of the concerns regarding the performance capability and reliability of service and cooling water systems at the 41 affected plants either have been addressed or are being addressed in the issues discussed above. Additionally, a staff action plan was developed that established NRR as the focal point to ensure that all existing and future SWS issues are adequately addressed.[1367] Therefore, Issue 156.3.2 was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.3.3: VENTILATION SYSTEMS

DESCRIPTION

This issue is one of nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] At issue was the adequacy of ventilation systems to provide a safe environment for plant personnel and ESF systems under normal, anticipated transient, and design basis operational conditions. A safe environment is one that is effectively controlled with respect to radiation, heat, humidity, smoke, and toxic gases. Five ventilation systems were identified in SRP[11] Section 9.4 to effect ESF equipment and plant personnel: the control room area, spent fuel area, auxiliary and radwaste area, turbine area, and ESF area.

With respect to plant personnel, the concerns about ventilation are grouped under radiation exposure as the first, and exposure to excessive levels of

environmental pollutants such as smoke, toxic gases, heat, and humidity as the second. These concerns may be considered for both normal operating and abnormal conditions. For normal conditions, the first concern is addressed by existing regulations in 10 CFR 20 which is quite clear and comprehensive concerning monitoring of restricted and unrestricted areas and radiation limits in each. In particular, 10 CFR 20.106 applies to radioactivity in effluent between restricted and unrestricted areas. Coverage includes limits of concentrations of radioactive material in air as well as water. For applications filed after January 2, 1971, 10 CFR 50.34a requires ALARA programs which are elaborated upon in 10 CFR 50, Appendix I. In addition, 10 CFR 50.34a requires design and installation of equipment "to maintain control over radioactive materials in gaseous and liquid effluent" not only during normal operations but also during expected operational occurrences. 10 CFR 50.36a requires TS on effluent from nuclear power reactors.

For normal operating conditions, the second concern is the responsibility of OSHA whenever the safety of licensed radioactive materials is not involved. This responsibility was outlined in an MOU between OSHA and the NRC issued on October 25, 1988. For abnormal conditions, the second concern comprises potentially unpleasant plant nuisance factors with the exception of the control room and turbine area. One potentially serious atmospheric contaminant in the turbine building and the auxiliary building of PWRs is H_2 with its potential for deflagration or detonation. Issue 106 addressed the role of ventilation systems in the prevention of H_2 deflagration from leaks in the H_2 distribution piping.

Issue 136 addressed the issue of vapor clouds from liquified combustible gases drifting into safety-related air intakes.

Abnormal control room environmental conditions could exist that adversely affect operator performance to a degree sufficient to cause operator-initiated transients. These conditions are within the NRC scope as defined in the above MOU. Conditions affecting mitigation of accidents are also clearly NRC responsibility. The resolution of Issue 83 will address the limits of plant personnel functioning from radiation and toxic gas exposure. The scope of Issue 83 includes "provisions for personnel to remain in the control room as needed to manage accidents which have the potential for offsite and onsite radiological consequences, and protection of control room occupants to the degree necessary to prevent an accident occurring as a result of operator incapacitation." SRP[11] Section 6.4, Rev. 2, describes review of the control room ventilation system with the objective of assuring protection for plant operators from the effects of accidental releases of toxic and radioactive gases. A third revision draft is under consideration as part of the resolution of Issue 83. Thus, accident initiation and mitigation capabilities of control room personnel are being addressed with respect to radiation and toxic gas exposure. Control room concerns remaining are high temperature and humidity and smoke.

With respect to high temperature and humidity, the ACRS recommended that "[t]emperature limits should be revised taking into account low air exchange rate, operation of ESF filter system heaters and perspiration." The ACRS considers a temperature limit of 120°F for the control room as unacceptable; this is a TS limit derived for control room equipment.[678] Under accident conditions, no NRC requirement exists for temperature limits for reliable performance of control room personnel. However, documentation exists that supports a maximum effective temperature of 85°F for reliable human performance. (A defined effective temperature includes some combination of dry bulb temperature, relative

humidity, and air velocity). Although no accident condition temperature limit has been formalized, SRP[11] Section 9.4.1, "Control Room Area Ventilation System," concerns itself in part with "...the comfort of control room personnel during normal operating, anticipated operational transient, and design basis accident conditions." The control room area ventilation system (CRAVS) is reviewed, among other things, with respect to ability to maintain a suitable ambient temperature for control room personnel. The single failure criterion is applied in the CRAVS review. In addition, the CRAVS must function unaffected by loss of equipment that is not seismic Category 1 and the integrated system design must satisfy GDC 2 with respect to earthquakes. The designs are reviewed for protection from floods, hurricanes, tornadoes, internally- or externally-generated missiles, fires, and loss of offsite power. At some plants, the CRAVS is capable of functioning in an internal-filtered recirculation mode of operation.

A survey of 12 plants reported some problems with adequacy and demonstration of adequacy of control room cooling for a postulated 30-day accident period.[1371] The plants surveyed were a mix of ages, ranging from some of the oldest to some of the newest. While the problems identified produced no added industry requirements, a recommendation was made for more [staff] attention to detail in evaluations of control room cooling systems design and operations that rely on two separate cooling systems, i.e., a non-safety-related system for normal operations and a safety-related system for emergency operations only. In sum, no additional regulatory requirements or guidance are warranted for investigation with respect to high temperature and humidity vis-a-vis control room personnel under accident conditions.

Issue 143 is to be resolved and will address the importance of ventilation systems on cooling for the operation of ESF equipment. Activities in support of the resolution of Issue 143 will identify the vulnerabilities of safety-related systems and their support systems to the effects of HVAC and chilled water system failures and adverse temperature fluctuations. An evaluation will be made of equipment environmental qualification, equipment room heat load and heat-up rate to identify areas in which a reduction in the dependence of equipment operability on HVAC and room cooling may be required. The control of smoke in plants is being addressed in Issue 148.

CONCLUSION

The safety concerns of Issue 156.3.3 were either being addressed in ongoing staff actions on Issues 83, 106, 136, 143, and 148, or were covered by existing regulations. Therefore, Issue 156.3.3 was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.3.4: ISOLATION OF HIGH AND LOW PRESSURE SYSTEMS

DESCRIPTION

This issue is one of nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] At issue were low pressure systems (such as the RHR systems) that interface with the reactor coolant system through isolation valves. The concern was that systems with low design pressure, in comparison with reactor coolant pressure, will incur damage due to valve failure or inadvertent valve opening.

Issue 105 addressed the possible breach of those interfacing boundaries that are created by a series of PIVs and the consequences of failure of a boundary by mechanical failure, human error, or external event. Thus, Issue 105 covered all interfacing systems, including those identified in Issue 156.3.4. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

CONCLUSION

The safety concern of Issue 156.3.4 was addressed in the resolution of Issue 105. Therefore, Issue 156.3.4 was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.3.5: AUTOMATIC ECCS SWITCHOVER

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] Most PWRs require operator action to realign the ECCS for the recirculation mode following a LOCA. Existing guidelines state that automatic transfer to the recirculation mode is preferable to manual transfer. However, a design that provides manual switchover is sufficient provided that adequate instrumentation and information displays are available for the operator to manually transfer from the injection mode to the recirculation mode at the correct time. Automatic in lieu of manual switchover could possibly provide an improvement of ECCS reliability at a cost that could result in a worthwhile safety enhancement. This issue addressed the procedures for manual switchover, the adequacy of available instrumentation, and the possible operator errors associated with the switchover process. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

CONCLUSION

All 41 plants affected by this issue were to be considered in the resolution of Issue 24 which was directed at studying the merits of manual, automatic, and semi-automatic ECCS switchover to recirculation. Thus, Issue 156.3.5 was covered in the resolution of Issue 24. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change this conclusion.

ISSUE 156.3.6.1: EMERGENCY AC POWER

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The electrical independence and redundancy of safety-related onsite power sources must meet the single failure criterion. Diesel generators, which provide emergency standby power for safe reactor shutdown in the event of total loss of offsite power, have experienced a significant number of failures over the years that have been attributed to a variety of causes, including failure of the air startup, fuel oil, and combustion air system. The objective of this issue was to review the reliability of protection interlocks and testing of diesel generators

to assure that diesel generator systems meet the availability requirements for providing emergency standby power to the engineered safety features, as well as the independence of onsite power distribution systems and features, such as automatic bus transfers and breaker connections, that could affect the independence of redundant trains. The 41 non-SEP plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

CONCLUSION

The safety concern of this issue was addressed in the resolution of Issues A-44, 128, and B-56. The requirements that resulted from the resolution of these three issues will affect the 41 non-SEP plants. In addition, MPAs B-23, "Degraded Grid Voltage," and B-48, "Adequacy of Station Electric Distribution Voltage," have been implemented at several of the 41 plants affected by this issue and will not have to be repeated in the implementation of the resolution of Issue A-44.[1108] Based on the above considerations, Issue 156.3.6.1 was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.3.6.2: EMERGENCY DC POWER

DESCRIPTION

Historical Background

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343[1351] following its study of how the lessons learned from the SEP have been factored into the licensing bases of operating plants. The issue addresses the concern that safety-related DC power system bus voltage monitoring and annunciation may not adequately notify operators of DC bus status. Responses to Generic Letter 91-06[1399] indicated that a significant number of licensees could be affected by the concerns of this issue. Based upon a PRA analysis of the DC power system at six plants, it was concluded that additional DC power system bus voltage monitoring and annunciation for licensed facilities would not have a significant impact on safety and would not be a cost-effective means of increasing plant safety.

This issue addressed the criteria in 10 CFR 50.55a(h) and 10 CFR 50 (GDC 2, 4, 5, 17, 18, and 19) which require that the control room operator be given timely indication of the status of the safety-related DC power system batteries and their availability. The current staff position is that the following separate and independent control room indications and alarms for the Class 1E DC power system status are recommended in order to meet these criteria:

(1) battery disconnect or circuit breaker open alarm
(2) battery charger disconnect or circuit breaker open alarm (both input AC and output DC)
(3) DC system ground alarm
(4) DC bus undervoltage alarm
(5) DC bus overvoltage alarm
(6) battery charger failure alarm
(7) battery discharge alarm

(8) battery float charge current ammeter
(9) battery circuit output current ammeter
(10) battery discharge indicator
(11) bus voltage voltmeter

These annunciators and alarms are needed in order to ensure that the control room operators are alerted in the event of DC power system or battery failure. If a less extensive configuration of equipment is used, it is possible that a DC power system or battery failure mode could exist which would not result in the actuation of any alarms or annunciators. In this event, the DC power supply would remain in the degraded condition until a periodic surveillance test or maintenance was performed to identify the condition of the batteries.

Safety Significance

Based upon the SEP reviews, it was apparent that some licensees had received operating licenses without providing the above recommended alarms and annunciators. However, in most cases the licensees in the SEP reviews were able to demonstrate to the staff that modifications were unnecessary. The concern in this issue is that some licensees that were not reviewed in the SEP program might have insufficient annunciators and alarms in the control room to alert the operators to some safety-related DC power supply or battery failure modes, which would increase the likelihood that a DC power supply is unavailable when needed.

PRIORITY DETERMINATION

The issue of control room annunciation and alarms for the safety-related DC power supplies was also addressed in Issue A-30 which was combined with other generic issues involving safety-related power supplies to form Issue 128. Generic Letters 91-06[1399] and 91-11[1400] were issued in the resolution of Issue 128; Generic Letter 91-06 addressed the concerns of Issue A-30. Industry organizations such as NUMARC and INPO asserted that most licensees already had alarm and annunciator configurations that were equivalent to the existing staff recommendations which were based in part on industry standards. Therefore, the questions in Generic Letter 91-06[1399] which addressed available alarms and annunciators did not represent a minimum acceptable configuration, but were formulated to provide sufficient information to the staff to determine if licensees had met or adequately addressed the current recommendations.

An INEL review[1457] of the responses to Generic Letter 91-06[1399] showed that 42 licensees do not have any separate and independent alarms in the control room for their DC power system. However, these licensees typically had local alarms which were separate and independent, and a single battery condition monitor which alarms in the control room in the event that one or more of the local battery alarms actuate. In addition, the INEL review indicated that 15 licensees have not performed a human factors review of their testing and maintenance procedures, and 5 licensees do not have procedures that specifically prevent simultaneous testing or maintenance of redundant safety-related DC power sources. In most cases, the licensees supplied justification for the discrepancies between their licensed configuration and the current staff position. INEL did not evaluate licensee responses to determine what modifications would be required to adequately resolve the concerns of Issue A-30, and recommended that the staff perform a PRA study to determine the impact on plant safety of existing configurations of safety-related DC power supply annunciation and alarms.

Frequency Estimate

The concern in this issue was that the safety-related DC power supplies might be unavailable because of inadequate control room annunciators and alarms. This concern correlates with the results of NUREG-0666,[164] which included a FMEA and a PRA of a model DC power system. This model system consisted of two independent DC buses each of which were supplied by a single battery charger and had a single battery back-up. In addition, this system had the following alarms and annunciators in the control room: (1) battery charger ground alarm; (2) battery charger AC power supply failure alarm; (3) DC bus undervoltage alarm; (4) battery charger DC ammeter; and (5) battery charger DC voltmeter.

NUREG-0666[164] concluded that battery unavailability is dominated by inadequate maintenance practices and failure to detect battery unavailability due to bus connection faults. By improving battery surveillance, DC power system unreliability could be decreased by a factor of two, and improving maintenance and testing practices could decrease DC power system unavailability by a factor of 10. The report does not quantify a safety benefit which would result from additional alarms or annunciators in the control room, but additional alarms and annunciators would result in the enhancement of surveillance, maintenance and testing capabilities. Additional recommendations were made in NUREG-0666,[164] but these relate to aspects of the DC system which would not be enhanced by the addition of alarms or annunciators, such as the addition of a third DC power train.

In addition to the concerns relating to alarms and annunciators, the responses to Generic Letter 91-06[1399] also identified concerns with the probability of CCF of the DC power supplies. In order to evaluate these two concerns, the PRAs for 6 licensees were reviewed and found to include basic events which modeled the probability of battery unavailability and common cause battery failure. A study was performed to determine the effect on the CDF of decreasing battery unavailability and common cause battery failure probability. This study was performed by the staff using the SARA[1456] software. The results are described below.

The assumption was made that improved alarms and annunciators would result in continuous battery condition indication and would essentially result in an undetected battery failure probability of zero, since the operators would be notified of a DC power system failure immediately. However, this approximation would give a greater estimate of the effectiveness of modifications of alarms and annunciators than could actually be obtained. A better estimate of the effect on DC power system reliability resulting from an increase in the number of alarms and annunciators in the control room was obtained by decreasing the battery unavailability from the base case value to a test case value of 10^{-6}. For the plants considered in this analysis, the base case values ranged from 6.12×10^{-3} to 7.2×10^{-4}, which reflects an hourly failure rate of approximately 10^{-6}/hour, and an interval between tests which are capable of detecting a failed battery ranging from 6,120 to 720 hours.

This modification in battery unavailability will also account for any decrease in the battery charger unavailability resulting from the additional hardware. Because the battery must be instantaneously available to supply power if the battery charger fails, the battery unavailability terms in a PRA model are always multiplied by the battery charger unavailability terms. This analysis is

conservative because it overestimates the effectiveness of additional alarms and annunciators, which will improve DC power system reliability by a much smaller factor. In addition, this approximation is made under the assumption that the DC power systems have been accurately modelled by PRA analysts for the existing PRAs and is only valid if the configuration of alarms and annunciators modelled by the existing PRAs is less effective than the currently recommended configuration.

CCF of the DC power system can be caused by maintenance activity, the most significant of which is inadvertent connection of redundant trains. Generic Letter 91-11[1400] addressed the use of interconnections between Class 1E vital instrument buses and LCOs for Class 1E vital instrument buses. The purpose of this generic letter was to decrease the probability and sources of CCF of redundant Class 1E AC and DC buses and inverters. It was assumed that CCF of the Class 1E buses and inverters has been adequately addressed and the scope of this issue was limited to the batteries and battery chargers.

The SARA[1456] software was used to model the effect of decreasing battery unavailability. There are currently nine operating plants which have PRA models which can be used with SARA. These are listed below, in addition to the configuration of the DC power system at the plant.

Plant	Number of 125 V DC Batteries	Number of Battery Chargers
Grand Gulf 1[1318]	3	6
Brunswick 1 & 2*	4 (each)	4 (each)
Peach Bottom 2*	4	4
Surry 1[1318]	2 + diesel	2
Sequoyah 1[1318]	2 + diesel + 1 common	2 + 1 common
Oconee 3[889]	2	3
Zion[1318]	2 + 1 common	2 + 1 common
Indian Point 2*	4	4

* Based on IPE Submittal

Peach Bottom Unit 2: This unit has two independent divisions of safety-related 125V DC power, one of which is required to safely shut down the plant. Each division is comprised of two batteries, each with it's own charger. The control room has 3 of 7 recommended alarms and 1 of 4 recommended annunciators. The Peach Bottom PRA included probability terms for battery unavailability due to common mode failure and unavailability of the individual Unit 2B and 3C battery banks. The terms for the remaining battery banks (2A, 2C, 2D, and 3D) were not included in any significant minimal cutsets, and decreasing these basic event probabilities would have a negligible effect on the CDF. The probability of battery unavailability was estimated in the original PRA to be 0.001.

Peach Bottom 2 - Common Mode Battery Failure

Probability	CDF/RY	Change/RY
0.001	3.6×10^{-6}	base case
0.000001	3.4×10^{-6}	-2.0×10^{-7}

Peach Bottom 2 - Battery 2B and 3C Failure

Probability	CDF/RY	Change/RY
0.001	3.6×10^{-6}	base case
0.000001	3.6×10^{-6}	-

Decreasing the probability of common mode battery unavailability by three orders of magnitude would result in a decrease in CDF of 2.0×10^{-7}/year, whereas decreasing the probability of the unavailability of batteries 2B and 3C would result in less than a 10^{-7} decrease in CDF.

Grand Gulf Unit 1: This unit has three independent divisions of safety-related 125V DC power, two of which are required to safely shut down the plant. The control room has 1 of 7 recommended alarms and 1 of 4 recommended annunciators. The Grand Gulf PRA included terms for the probability of battery common mode failure and failure of the individual Unit 1A3, 1B3, and 1C3 battery banks. All battery banks were included in significant minimal cutsets.

Grand Gulf 1 - Common Mode Battery Failure

Probability	CDF/RY	Change/RY
0.001	2.1×10^{-6}	base case
0.000001	1.6×10^{-6}	-5.0×10^{-7}

Grand Gulf 1 - Loss of Power from Batteries 1A3, 1B3, 1C3

Probability	CDF/RY	Change/RY
0.001	2.1×10^{-6}	base case
0.000001	1.9×10^{-6}	-2.0×10^{-7}

Decreasing common mode battery unavailability by three orders of magnitude would result in a decrease in CDF of 5×10^{-7}/RY, whereas decreasing the unavailability of battery 1A3, 1B3 and 1C3 would result in a decrease of 2×10^{-7} in CDF.

Brunswick Units 1 and 2: These units each have two independent divisions of safety-related 125V DC power, one of which is required to safely shut down the plant. Each division is comprised of two independent batteries, each with its own charger. The control room has 5 of 7 recommended alarms and 2 of 4 recommended annunciators. The Brunswick Units 1 and 2 PRAs included terms for the probability of individual battery bank unavailability but not for common cause unavailability. The terms for failure of three of the four batteries were included in some minimal cutsets.

Brunswick 1 - Battery Bank 1A1, 1A2, and 1B1 Fault

Probability	CDF/RY	Change/RY
0.00033	2.47×10^{-5}	base case
0.000001	2.46×10^{-5}	-1.0×10^{-7}

Brunswick 2 - Battery Bank 2A1, 2A2, and 2B1 Fault

Probability	CDF/RY	Change/RY
0.00033	2.08×10^{-5}	base case
0.000001	2.06×10^{-5}	-2.0×10^{-7}

Units 1 and 2 differed slightly in their response to battery failure rate changes. However, decreasing the unavailability of battery 2A1, 2A2, and 2B1 would result in a decrease of 10^{-7}/RY and 2 x 10^{-7}/RY in CDF for Unit 1 and 2, respectively.

Surry Unit 1: This unit has two independent divisions of safety-related 125V DC power, one of which is required to safely shut down the plant. The unit also has dedicated batteries for starting the diesel generators. The control room has 4 of 7 recommended alarms and 1 of 4 recommended annunciators. The Surry PRA included terms for the probability of battery common mode failure and failure of the individual I and II battery banks. Neither the common mode battery failure term or individual battery failure terms were included in any significant minimal cutsets. The assumed battery unavailability was 7.2 x 10^{-4}, which suggests a 2-month interval between tests that would detect battery problems for the typical failure rate. Because the CDF magnitude cutoff for exclusion of core damage sequences from the group of minimal cutsets is usually less than 10^{-8}, decreasing battery unavailability or common mode failure probability would result in a negligible decrease in CDF.

Sequoyah Unit 1: This unit has two independent divisions of safety-related 125V DC power, one of which is required to safely shut down the plant. The unit also has dedicated batteries for starting the diesel generators. The control room has zero of 7 recommended alarms and 3 of 4 recommended annunciators. The Sequoyah PRA included probabilities for battery common mode unavailability and unavailability of the individual I and II battery banks. Battery unavailability was initially estimated to be 7.2 x 10^{-4}, which suggests a two-month surveillance test or maintenance interval for a failure rate of 10^{-6}/hour. The common mode unavailability was estimated to be 5.8 x 10^{-6}. Neither the common mode unavailability or individual battery unavailability were included in any significant minimal cutsets. The unavailabilities used in this analysis were slightly lower than those used in other analyses. However, the CDF magnitude cutoff for exclusion of core damage sequences from the group of minimal cutsets is usually less than 10^{-8} or less. Therefore, decreasing battery unavailability or common mode failure probability would result in a negligible decrease in CDF.

Oconee Unit 3: This unit has two independent divisions of safety-related DC power, one of which is required to safely shut down the plant. The control room has 1 of 7 recommended alarms and none of 4 recommended annunciators. The Oconee PRA[889] included terms for unavailability of the individual 1CA, 1CB, 3CA, and 3CB battery banks. The probability of battery unavailability was estimated to be 6.12 x 10^{-3}, which is based on a one-year surveillance test or maintenance interval and a failure rate of 1.4 x 10^{-6}/hour. Common mode unavailability was not included in the PRA model. The individual battery unavailability terms were not included in any significant minimal cutsets. The probabilities used in this analysis were significantly greater than those used in other analyses. However, the CDF magnitude cutoff for exclusion of core damage sequences from the group of minimal cutsets is usually less than 10^{-8} or less. Therefore, decreasing battery unavailability or common mode failure probability would result in a negligible decrease in CDF.

The average decrease in CDF from the proposed modifications was estimated to be approximately 10^{-7}/RY.

Consequence Estimate

It was assumed that all affected operating plants had an average remaining life of 20 years, based on their original licenses. It was also assumed that each of these plants would be granted a life extension of 20 years. Thus, the average remaining life for all affected plants was 40 years.

The public risk associated with the event considered in this issue was estimated[64] to be 6.76×10^6 man-rem and 2.52×10^6 man-rem for BWRs and PWRs, respectively. For BWRs, the total potential risk reduction was estimated to be $(6.76 \times 10^6)(10^{-7})(40)$ man-rem/reactor or 27 man-rem/reactor. For PWRs, the total potential risk reduction was estimated to be $(2.52 \times 10^6)(10^{-7})(40)$ man-rem/reactor or 10 man-rem/reactor.

Cost Estimate

Improving the control room annunciators and alarms for all safety-related DC power systems at each plant would involve a different amount of effort for each licensee, depending upon the amount of instrumentation currently installed, available space for additional annunciators and alarms, and whether existing raceway could hold additional cables. In addition, new procedures and operator training would be required. This additional hardware would include the following:

(1)	Data transmitters at each battery room. Design, installation and testing assumed to be \$100,000/battery room, with 3 battery rooms per facility	\$300,000
(2)	Raceway and cable from each battery room to the control room. Design, installation and testing costs assumed to be \$100 per linear foot, with 1000 linear feet of raceway per battery room and 3 battery rooms per facility	\$300,000
(3)	Control room modifications to add annunciators and alarms. Design, installation and testing assumed to be \$100,000/battery, 3 batteries per facility	\$300,000
(4)	Procedure changes, drawing changes, training, and administrative costs	\$100,000
	TOTAL:	\$1,000,000

Value/Impact Assessment

Separate value/impact scores were calculated for PWRs and BWRs.

BWRs: Based on a potential public risk reduction of 27 man-rem/reactor and a cost of \$1M/reactor, the value/impact score was given by:

$$S = \frac{27 \text{ man-rem/reactor}}{\$1M/\text{plant}}$$

$$= 27 \text{ man-rem/\$M}$$

PWRs: Based on a potential public risk reduction of 10 man-rem/reactor and a cost of $1M/reactor, the value/impact score was given by;

$$S = \frac{10 \text{ man-rem/reactor}}{\$1M/\text{reactor}}$$

$$= 10 \text{ man-rem/}\$M$$

Other Considerations

(1) It is important to monitor the condition of the safety-related DC power system, including the condition of batteries which may be needed in the event of a station blackout. In addition, it is also necessary to have procedures which minimize the probability of a common cause fault of the safety-related DC power systems. Operating experience so far does not indicate that significant problems exist in this area.

(2) Based upon the results of this study, it could be asserted that the control room alarms and annunciators recommended by the staff in current licensing guidelines do not result in a significant increase in plant safety beyond that realized by existing alarm and annunciator configurations and weekly or quarterly maintenance programs. It should be noted that the empirical battery failure rate of approximately 10^{-6}/hour, which is used to determine battery unavailability, is dependent upon the frequency of battery failures for systems with existing configurations of control room annunciators and alarms. Therefore, it might not be accurate to conclude that the existing recommendations for annunciators and alarms should be relaxed.

(3) Battery unavailability and CCF are recognized by some licensees to be sufficiently probable so as to require modelling in PRAs. Based upon these PRA models, decreasing the unavailability of the batteries and safety-related DC power supplies by several orders of magnitude over that used in the base case does not result in a significant decrease in CDF for these licensees. This observation must be tempered with the knowledge that licensees currently monitor important DC bus parameters, and that other DC power system design features, such as the number of batteries, have a greater impact on DC power system reliability than the number of alarms and annunciators.

CONCLUSION

Based on the potential public risk reduction, this issue had a low priority ranking for BWRs and was in the drop category for PWRs (See Appendix C). Overall, the issue was given a LOW priority ranking. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.3.8: SHARED SYSTEMS

DESCRIPTION

This issue is one of the nineteen category 3 issues identified by NRR in SECY-90-343.[1351] The sharing of the ESFS for a multi-unit plant, including onsite emergency power systems and service systems, can result in a reduction of the number and capacity of onsite systems to below that which is needed to bring either unit to a safe shutdown condition, or to mitigate the consequences of an accident. Shared systems for multiple unit stations should include equipment powered from each of the units involved. There were 13 multi-unit sites that could be affected by this issue among the 41 non-SEP plants identified in SECY-90-343[1351] that received OLs before 1976.

CONCLUSION

The safety concerns associated with systems that are shared by two or more units at multi-unit sites have been previously identified by the staff. The most important contributors to core damage probability at these sites have been determined to be air, cooling water, and electric power systems. These systems have been adequately addressed in Issues 43, 130, 153, and A-44. Based on these considerations, this issue was DROPPED from further pursuit as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

ISSUE 156.4.1: RPS AND ESFS ISOLATION

DESCRIPTION

This issue is one of the three Category 4 issues identified by NRR in SECY-90-343.[1351] The safety concern was that, in the event of non-safety system failures, the lack of isolation devices could result in the propagation of faults to safety systems and common cause failures may result. In its study, the staff found that approximately 39 plants at 28 sites were not required to meet IEEE 279-1971[397] and have not been reviewed for this safety concern since the time of their licensing.

Non-safety systems generally receive control signals from the RPS and ESF sensor current loops. The non-safety circuits are required to be isolated to ensure the independence of the RPS and ESF channels. Requirements for the design and qualification of isolation devices are quite specific. Evaluation of the quality of isolation devices is not the safety issue of concern; rather, the issue is the existence of isolation devices which will preclude the propagation of non-safety system faults to safety systems.

CONCLUSION

The safety concerns of leakage through electrical isolators in instrumentation circuits and electrical isolation in plants not required to meet IEEE 279-1971[397] were addressed in the resolution of Issue 142. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change this conclusion.

ISSUE 156.4.2: TESTING OF THE RPS AND ESFS

DESCRIPTION

This issue is one of the nineteen Category 3 issues identified by NRR in SECY-90-343.[1351] The objective of this issue was to review plant designs to ensure that: (1) all ECCS components, including the pumps and valves, are included in the component and system test; (2) the frequency and scope of periodic testing are identified; and (3) the test programs will provide adequate assurance that the systems will function when needed. The 41 plants identified in SECY-90-343[1351] that received OLs before 1976 were affected by this issue.

CONCLUSION

A portion of this issue was covered by existing requirements; specifically, ECCS pumps and valves are required to be tested quarterly by the ASME Code in accordance with 10 CFR 50.55(a), unless the NRC grants relief to defer testing until refueling outages. The remainder of this issue was covered in the resolution of Issue 120 which addressed the concern regarding on-line (at-power) testability af protection systems (both the RPS and the ESFS) and the possibility that some plants may not provide complete testing capability at power. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change this conclusion.

ISSUE 156.6.1: PIPE BREAK EFFECTS ON SYSTEMS AND COMPONENTS

This issue is being prioritized.

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ISSUE 157: CONTAINMENT PERFORMANCE

The results of ongoing staff-sponsored research which culminated in the assessment of risk at five U.S. nuclear reactors (NUREG-1150[1081]) indicated that, for the Peach Bottom MARK I containment, the core-melt probability was relatively low. However, it also indicated that the containment could be severely challenged if a large core-melt occurred. Therefore, it was decided to examine MARK I plants for potential plant and containment modifications to improve containment performance. Subsequently, this examination was expanded to include all other types of containment: MARK II, MARK III, Ice Condenser, and Dry. These studies were conducted under the Containment Performance Improvement (CPI) program, the results of which are documented by containment type below. Thus, based on the staff's evaluations of each of the five types of containments, this issue was RESOLVED. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

(1) MARK I CONTAINMENTS

DESCRIPTION

Historical Background

At the time of this evaluation in February 1992, there were 24 BWRs with MARK I containments at 17 sites. The staff issued a plan in December 1987 to address the performance of MARK I containments (SECY-87-297).[1458] This plan involved identification and narrowing of issues, focusing related research, and assessing whether improvements were justified.

Safety Significance

The containment represents the final barrier to the release of radioactive material to the environment. GDC 16 requires a leaktight containment and its failure, especially early in a severe accident, has the potential for a significant release of radioactivity to the environment.

Possible Solutions

Potential containment and plant improvements in the following six areas were evaluated to determine potential benefits in terms of reducing the core-melt frequency, containment failure probability, and offsite consequences: (1) hydrogen control; (2) alternate water supply for reactor vessel injection and containment drywell sprays; (3) containment pressure relief capability (venting); (4) enhanced RPV depressurization system reliability; (5) core debris controls; and (6) emergency procedures and training.

Hydrogen Control: Although MARK I containments are required to be operated with an inerted atmosphere, plant TS permit deinerting to commence 24 hours prior to shutdown and do not require inerting to be completed until 24 hours after startup, in order to permit personnel access. Also, in the event of a severe accident such as a long-term station blackout, a concern was expressed that loss

of control of the valves and containment leakage could eventually lead to containment deinerting.

Two potential improvements with regard to H_2 control were evaluated: elimination of the the 24-hour deinerted periods and providing a backup supply of nitrogen. Since the probability of a severe accident occurring during either of the two 24-hour deinerted periods is small compared to the probability of accident occurrence during normal operations, eliminating this time of deinerting would not significantly reduce risk.

Reactor pressure is anticipated to increase during a severe accident, releasing steam and non-condensible gases into containment. This will increase containment pressure, preventing ingress of air. Therefore, the containment atmosphere would not become deinerted for an extended period of time. Since offsite supplies of nitrogen could be readily obtained during this period, an onsite backup supply of nitrogen would not significantly reduce risk.

Alternate Water Supply for Reactor Vessel Injection and Containment Drywell Sprays: An important proposed improvement was to employ a backup or alternate supply of water and a pumping capability independent of normal and emergency AC power. By connecting this source to the low pressure residual heat removal system as well as to the existing drywell sprays, water could be delivered either into the reactor vessel or to the drywell by use of an appropriate valve arrangement. An alternate source of water injection into the reactor vessel would reduce the likelihood of core-melt due to station blackout or loss of long-term decay heat removal, as well as provide significant accident management capability.

Water for the drywell sprays would also provide significant mitigative capability to cool the containment steel shell to delay or prevent its failure and either to cool core debris or, if the debris configuration is not coolable, to scrub particulate fission products through an overlying water pool.

A review of some MARK I facilities indicated that most plants have one or more diesel-driven pumps which could be used to provide an alternate water supply. The flow rate using this backup water system may be significantly less than the design flow rate for the drywell sprays. The potential benefits of modifying the spray headers to ensure a spray were compared to having the water run out of the spray nozzles. The result of this comparison was that removal of airborne fission products in the small crowded volume in which the sprays would be effective did not change sufficiently to warrant modifications to the spray nozzles.

Containment Pressure Relief Capability (Venting): Venting of the containment is currently included in BWR emergency operating procedures. The vent path external to existing containment penetrations typically consists of a ductwork system which has a low design pressure of only a few pounds per square inch gauge (psig). Venting under high pressure severe accident conditions would fail the ductwork, release the containment atmosphere into the reactor building, and potentially contaminate or damage equipment needed for accident recovery. In addition, with the existing hardware and procedures at some plants, it may not be possible to open or close the vent valves for some severe accident scenarios.

The staff concluded that venting, if properly implemented, could have a significant benefit on plant risk. However, venting via a sheet metal ductwork path, as currently implemented at some MARK I plants, would be likely to greatly

hamper or complicate post-accident recovery activities, and was therefore viewed by the staff as yielding reduced improvements in safety. The capability to vent has been recognized as important in reducing risk from operation of MARK I plants for loss of long-term decay heat removal (TW) events, provided the potential downsides of using existing hardware are corrected. Controlled venting can prevent the failure of ECCS pumps from both inadequate NPSH and re-closure of the ADS valves.

A hard pipe vent and vent valves capable of withstanding the anticipated severe accident pressure loadings would eliminate the problems with operating the vent system during a severe accident. The vent isolation valves should be remotely operable from the control room and should be provided with a power supply independent of normal or emergency AC power. Other changes, such as raising the RCIC turbine back-pressure setpoint, may also be desirable and could be considered. Venting capability, in conjunction with proper operating procedures and other improvements discussed in this item, would greatly reduce the probability of core-melt due to TW and station blackout sequences.

Given a core-melt accident, venting of the wetwell would provide a scrubbed vent path to reduce release of particulate fission products to the environment. Venting has been estimated to reduce the likelihood of late containment overpressure failure and to reduce offsite consequences for severe accident scenarios in which the containment shell does not fail for other reasons. Failure of the shell due to core debris attack (shell melt-through) would reduce the benefits from venting in that it would release fission products directly into the reactor building.

Inadvertent venting could result in the release of normal coolant radioactivity to the environment even when core degradation is averted or vessel integrity maintained. Measures to reduce the probability of inadvertent venting should be considered in the vent design.

Enhanced RPV Depressurization System Reliability: The ADS consists of safety relief valves which can be remotely operated to depressurize the RCS. Actuation of the ADS valves requires DC power. In an extended station blackout after station batteries have been depleted, the ADS would not be available and the reactor would re-pressurize. With enhanced RPV depressurization system reliability, depressurization of the RCS would have a greater degree of assurance. A major benefit of enhanced RPV depressurization reliability would be to significantly reduce the likelihood of high pressure severe accidents, such as from short-term station blackout. Together with a low pressure alternate source of water injection into the reactor vessel, another benefit would be to reduce the likelihood of low pressure severe accidents such as from long-term station blackout.

An additional benefit is in the area of accident mitigation. Reduced reactor pressure would reduce the possibility of core debris being expelled under high pressure, given a core-melt and failure of the RPV. Enhanced RPV depressurization system reliability would also delay containment failure and could reduce the quantity and type of fission products ultimately released to the environment.

In order to increase reliability of the RPV depressurization system, assurance of electrical power beyond the requirements of existing regulations may be

necessary. In addition, performance of the cables needs to be reviewed for temperature capability during a severe accident.

Core Debris Controls: Core debris controls, in the form of curbs in the drywell or curbs or weir walls in the torus room under the wetwell, have been proposed in the past to prevent containment shell melt-through or to retain sufficient water to permit fission product scrubbing. However, the technical feasibility of such controls has not been established and the design and installation costs as well as ORE during installation could be significant. There is a growing consensus that water in the containment (from an alternate supply to the drywell sprays) may help mitigate risk by fission product scrubbing and possibly by preventing or delaying containment shell melt-through by core debris. Research is continuing under the SARP[1382,1461] to confirm and help quantify these initial conclusions.

Emergency Procedures and Training: A major element of the MARK I containment performance improvement evaluation involves emergency procedures and training. Current EOPs are symptom-based procedures that originated from requirements of TMI Action Plan Item I.C.1. Plant-specific EOPs are generally implemented based on generic Emergency Procedure Guidelines (EPG) developed by the BWR Owners' Group. As part of the balanced approach to examining potential MARK I plant improvements, both the generic EPGs and the plant-specific implementation of EOPs and training have been examined.

NRC reviewed and approved Revision 4 of the BWR Owners' Group EPGs (NEDO-31331, Rev. 4, March 1987) which represented a significant improvement over earlier versions in that they continued to be based on symptoms, were simplified, and all open items from previous versions were resolved. The BWR EPGs extend well beyond the design bases and include many actions appropriate for severe accident management.

The improvement to EPGs is only as good as the plant-specific EOP implementation and the training that operators receive on use of the improved procedures. The staff's SER[1462] encouraged licensees to implement Revision 4 of the EPGs and reiterated the need for proper implementation and training of operators. Implementation of the EPGs has been voluntary, but was strongly recommended in the SER.

Accelerated Rule Implementation (ARI) for Station Blackout: In addition to the above six areas examined by the staff for containment and plant improvements, the staff evaluated accelerated implementation of the Station Blackout Rule (10 CFR 50.63). As indicated below, the staff's cost-benefit analysis found accelerated implementation to be cost-effective.

PRIORITY DETERMINATION

Table 3.157-1 gives a summary of the staff's cost-benefit analysis. The ranges for Alternatives 3 through 6 are due to the effects of TW frequency and two installation cost estimates. The detailed cost-benefit analysis is given in the enclosures to SECY-89-017.[1459]

Based on the cost-benefit analysis, the staff recommended that the Commission issue an order to accomplish Alternative 6. In response to the staff's recommendation, the Commission requested[1460] that the staff do the following: (1)

expedite rule implementation for Station Blackout; (2) request licensees to consider the ADS and alternate water supply modifications as part of their IPEs; and (3) approve hardened vents for licensees who propose to install them and perform a backfit analysis for licensees who do not propose to install them.

TABLE 3.157-1

Cost-Benefit of Alternatives

Alternative	Action	Man-Rem/$M
1	Do Nothing	0
2	ARI	990
3	ARI and Venting	4,060 to 9,630
4	ARI and ADS	72 to 290
5	ARI and Alternate Water Supply	62 to 190
6	ARI, Venting, ADS, and Alternate Water Supply	1,810 to 14,400

CONCLUSION

The staff issued Supplement 1 to Generic Letter 88-20[1222] to request that licensees with MARK I containments consider the ADS and alternate water supply modifications as part of their IPEs. Also, the staff issued Generic Letter 89-16[1463] to indicate that the staff would approve hardened vents for MARK I licensees who proposed to install them. Thus, this item was RESOLVED.

(2) MARK II CONTAINMENTS

DESCRIPTION

Historical Background

At the time of this evaluation in February 1992, there were 9 BWRs with MARK II containments located at 6 sites. The geometry of the reactor pedestal support and downcomers has a major impact on the performance of the containment, if the reactor vessel fails in a severe accident. Three major variations in geometry exist.

Safety Significance

The containment represents the final barrier to the release of radioactive material to the environment. GDC 16 requires a leak-tight containment and its failure, especially early in a severe accident, has the potential for a significant release of radioactivity to the environment.

Possible Solutions

Based on PRA insights, MARK II containment vulnerabilities and potential improvements that have been investigated are similar to those investigated for MARK I containments.

Staff-recommended MARK I improvements, other than the hardened vent, are being investigated under the IPE Program for MARK I plants. It is appropriate that MARK II licensees also investigate these same improvements on a plant-specific basis under the IPE Program, since they may also be generally applicable to these plants. However, less definitive conclusions have been reached regarding the need for improved venting of MARK II containments. The primary benefit from venting remains the same as for MARK I plants,i.e., the prevention of core-melt for loss of long-term decay heat removal (TW) sequence. However, some additional considerations come into play for MARK II plants. Some MARK II plants may already have the capability to vent through a hardened pipe. In addition, due to the larger volume of the MARK II containments, the time available for operator recovery actions during a TW sequence may be longer. Thus, the likelihood that venting will be required is expected to be less in a MARK II plant compared with a MARK I plant. For these reasons, the risk reduction to be gained from improvements to the vent system for MARK II plants may be less than for MARK I plants.

For less probable cases in which venting is initiated after core-melt has occurred, there is uncertainty in the incremental benefit of scrubbing the fission products by the suppression pool during venting at a Mark II. This is because molten core material on the floor of the Mark II containment may fail downcomers or drain lines and result in suppression pool bypass. Performing analysis of severe accidents for Mark II plants required use of Revision 4 of the EPG entitled "Steam Cooling." The analysis indicated that using Revision 4 could result in less operator response time (up to 30 minutes less) until the onset of core degradation as compared with using Revision 3. The staff's findings were presented to the BWR Owners Group. Subsequently, the BWR Owners' Group issued an interim change to Revision 4 to provide additional operator response time.

CONCLUSION

Aside from a change to Revision 4 of the EPGs, the staff did not identify any generic improvements that would be applicable to all Mark II containments. Therefore, the staff issued Supplement 3 to Generic Letter 88-20[1222] which requested that each licensee with a MARK II containment consider, as part of its IPE, the insights and improvements identified in the CPI Program. Thus, this item was RESOLVED.

(3) MARK III CONTAINMENTS

DESCRIPTION

Historical Background

At the time of this evaluation in February 1992, there were 4 operating BWRs with MARK III containments located at 4 sites. The MARK III containment is approximately five times the volume of the MARK I containment and 65% to 85% of

the volume of a large, dry PWR containment. The containment design pressure is 15 psig (25% of a MARK I, 30% of a large dry).

Unlike MARK I and II containments, the MARK III containment is not inerted and has igniters for H_2 control. The only PRA performed on a BWR with a MARK III containment was for Grand Gulf as part of the NUREG-1150[1081] studies.

The low core-melt frequency (on the order of 10^{-6}/year) estimated by the NUREG-1150[1081] studies was primarily due to the fact that Grand Gulf was a modern BWR design with a diversity of ways to provide water to the core. Grand Gulf uses a motor-driven High Pressure Core Spray with a dedicated diesel generator which improves the reliability of this system for mitigation of transients and small LOCAs. In addition, Grand Gulf has a number of low pressure coolant injection systems. Thus, Grand Gulf already has a number of diverse systems such as those studied for other BWR plants (e.g., diverse alternative supplies of water to the reactor). At least one such system (fire water connection) was implemented by the licensee as a direct result of the NUREG-1150[1081] studies.

Safety Significance

The containment represents the final barrier to the release of radioactive material to the environment. GDC 16 requires a leak-tight containment and its failure, especially early in a severe accident, has the potential for a significant release of radioactivity to the environment.

Possible Solutions

Based on PRA insights, potential plant improvements that were investigated are similar to those investigated for MARK I plants and thus would also be appropriate for evaluation on a plant-specific basis. Because of the relatively large volume of the MARK III containment, the need for venting may also be less likely than for the MARK I containment. Also, some MARK III plants may already have the capability to vent through a hardened system. In addition, the staff's analysis indicates that if the containment is vented the following could occur: (1) more radioactive material may be released to the environment than if the containment is not vented; (2) there is a potential increase in the probability of an H_2 deflagration or detonation; and (3) a vented containment will not prevent containment failure if an H_2 detonation were to occur. The analysis further indicates that for a short-term station blackout there is a very small amount of time when an H_2 deflagration or detonation could occur in the drywell and, in the absence of an H_2 deflagration or detonation, there is a high probability that there will be no containment failure during the accident. Thus, no generic conclusion could be reached regarding the need for venting for MARK III plants.

A potential vulnerability for MARK III plants involves station blackout, during which the igniters would be inoperable. Under these conditions, a detonable mixture of H_2 could develop which could be ignited upon restoration of power. A potential improvement considered for MARK III containments is a backup power supply in order to be able to use igniters during a station blackout. However, no generic conclusions could be reached. (At least one licensee has taken the position that use of igniters is not necessary during a station blackout.)

CONCLUSION

The staff did not identify any generic improvements that would be applicable to all MARK III containments. Therefore, the staff issued Supplement 3 to Generic Letter 88-20[1222] which requested that each licensee with a MARK III containment consider, as part of its IPE, the insights and improvements identified in the CPI program. Thus, this item was RESOLVED.

(4) ICE CONDENSER CONTAINMENTS

DESCRIPTION

Historical Background

At the time of this evaluation in February 1992, there were 10 reactors with ice condenser containments located at 5 sites. The ice condenser/containment houses a four-loop W PWR, is typically about 1.2 million cubic feet in volume, and has a design pressure of 12 to 15 psig. The NUREG-1150[1081] evaluation of the Sequoyah plant provided the most up-to-date insights into the important contributors to core damage and containment challenges that face an ice condenser plant. In using these results care must be taken, however, to ensure that they are representative of other ice condenser containment plants. For instance, the loss of offsite power initiating event frequency is lower for Sequoyah than for other ice condenser plants because of the offsite grid reliability. Also, because of design differences, significant variation has been reported in calculations of the ultimate failure capability of containments. Estimates have ranged from 60 psig for Sequoyah to 120 psig for Watts Bar.

Safety Significance

The containment represents the final barrier to the release of radioactive material to the environment. GDC 16 requires a leak-tight containment and its failure, especially early in a severe accident, has the potential for a significant release of radioactivity to the environment.

Possible Solutions

The Sequoyah risk analysis indicated that containment bypass sequences dominate early fatality risk. Timing is a key factor in these sequences as is a lack of any mitigating systems to scrub the release. The CPI Program did not address this area, because there was a joint NRR/RES program on interfacing system LOCAs that was underway to develop guidance and possible additional requirements for interfacing system LOCAs, including those that could bypass the containment. In addition, interfacing system LOCAs were to be considered as part of the IPE.

Direct containment heating (DCH) is a phenomenon that has a great deal of uncertainty associated with it. Risk assessments have varied considerably in their characterizations of its contribution to containment failure by overpressurization. Because of this uncertainty, research is being performed under the SARP[1382] to reduce the uncertainty in risk due to DCH. In addition, the staff is investigating, as part of the Accident Management Program, possible means to prevent or decrease the severity of DCH events. The principal strategy being investigated was that of full or partial depressurization of the RCS. The

CPI Program made use of the ongoing Accident Management Program work on depressurization and evaluated the impact of depressurization on the ice condenser containment. An important finding was that depressurization to prevent DCH for ice condenser plants is not sufficient to prevent containment failure unless the igniters are operating to control the large amount of H_2 that may be produced.

Containment failure resulting from uncontrolled H_2 burns or detonations is a potentially important failure mode for ice condenser containments. This could occur in station blackout events if power to the H_2 igniter system is lost, high concentrations of H_2 are produced as a result of core degradation, and power is then restored at a later time.

CONCLUSION

The staff did not identify any generic improvements that would be applicable to all ice condenser containments. Therefore, the staff issued Supplement 3 to Generic Letter 88-20[1222] which requested each licensee with an ice condenser containment consider, as part of its IPE, the insights and improvements identified in the CPI Program. Thus, this item was RESOLVED.

(5) DRY CONTAINMENTS

DESCRIPTION

Historical Background

At the time of this evaluation in February 1992, there were 63 PWR plants with large, dry containments located at 40 sites. There were also 7 PWRs located at 4 sites that used subatmospheric containments. The volume and design pressure of a large, dry containment are typically about 2.5 million cubic feet and 60 psig, respectively. The containment volume and design pressure of a subatmospheric containment are typically about 2 million cubic feet and 45 psig, respectively.

Safety Significance

The containment represents the final barrier to the release of radioactive material to the environment. GDC 16 requires a leak-tight containment and its failure, especially early in a severe accident, has the potential for a significant release of radioactivity to the environment.

Possible Solutions

NUREG-1150[1081] indicated that, given a core-melt, the conditional probability of early containment failure for a large, dry containment is low. For the Surry plant, containment bypass was found to be the dominant contributor to risk. However, containment bypass was not investigated further under the CPI Program because of the ongoing activities in this area discussed under Ice Condenser Containments above.

DCH was not important for the dry containments studied in NUREG-1150.[1081] However, as noted above, this is an area of large uncertainty and the importance of DCH to risk may vary for plants with dry containments other than those studied in

NUREG-1150.[1081] Research is ongoing to reduce the uncertainty in risk due to DCH. Depressurization to avoid DCH is being investigated as part of the Accident Management Program.

NUREG-1150[1081] did not identify H_2 combustion as a significant threat to the containment for the two PWR plants investigated. However, the staff does not know whether this conclusion can be extended to all PWR containments.

H_2 combustion on a global basis is not believed to be a significant threat to large, dry containments. However, less firm conclusions have been reached for the smaller subatmospheric containments. It may also be possible for detonable mixtures of H_2 to buildup in localized compartments of both types of dry containments and damage equipment. Therefore, the potential and effects of local H_2 burns should be evaluated on a plant-specific basis.

CONCLUSION

The staff did not identify any generic improvements that would be applicable to all dry containments. Therefore, the staff issued Supplement 3 to Generic Letter 88-20[1222] which requested each licensee with a dry containment to consider, as part of its IPE, the insights and improvements identified in the CPI Program. Thus, this item was RESOLVED.

REFERENCES

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1081. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Vol. 1) December 1990, (Vol. 2) December 1990, (Vol. 3) January 1991.

1382. NUREG-1365, "Revised Severe Accident Research Program Plan," U.S. Nuclear Regulatory Commission, August 1989, (Rev. 1) December 1992.

1458. SECY-87-297, "MARK I Containment Performance Program Plan," December 8, 1987.

1459. SECY-89-017, "MARK I Containment Performance Improvement Program," January 23, 1989.

1460. Memorandum for V. Stello from S. Chilk, "SECY-89-017 - MARK I Containment Performance Improvement Program," July 11, 1989.

1461. SECY-91-316, "Status of Severe Accident Research," October 7, 1991.

1462. Letter to D. Grace (BWR Owners' Group) from A.Thadani (NRC), "Safety Evaluation of 'BWR Owners' Group - Emergency Procedure Guidelines, Revision 4,' NEDO-31331, March 1987," September 12, 1988.

1463. NRC Letter to All Holders of Operating Licenses for Nuclear Power Reactors With Mark I Containments, "Installation of a Hardened Wetwell Vent (Generic Letter No. 89-16)," September 1, 1989.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 158: PERFORMANCE OF SAFETY-RELATED POWER-OPERATED VALVES UNDER DESIGN BASIS CONDITIONS

DESCRIPTION

Historical Background

This issue was identified[1481] by NRR after reactor operating experience and research results on MOVs, SOVs, AOVs, and HOVs indicated that testing under static conditions did not always reveal how these valves would perform under design basis conditions. A number of failures of power-operated valves had occurred as a result of inadequate design, installation, and maintenance. Operating events involving observed or potential common mode failures of AOVs, SOVs, and MOVs were documented in NUREG-1275,[1079] NUREG/CP-0123, and AEOD/C603. Events that specifically involved AOVs and SOVs were identified in Volumes 2 and 6 of NUREG-1275.[1079]

Concerns regarding the performance of MOVs were resolved in Issue II.E.6.1 and resulted in the issuance of Generic Letter 89-10[1217] which required licensees to establish programs to ensure the operability of MOVs in safety-related systems. In addition, the reliability of PORVs and SVs was addressed in the resolution of Issue 70. Although no study was available on HOVs that highlighted significant events involving observed or potential common mode failures or degradation, HOVs are used in many plants as MSIVs and in the AFWS at PWRs and SWS at BWRs. The use of power-operated valves in safety systems is sufficiently widespread to raise concerns similar to those on MOVs addressed in the implementation of Generic Letter No. 89-10.[1217] Therefore, this analysis focused on power-operated valves other than MOVs.

Safety Significance

Appendix A to 10 CFR 50 requires that components important to safety be designed and tested to quality standards commensurate with the importance of the safety function to be performed. Based on the experience gained by the staff in the resolution of issues concerning MOVs, malfunctioning of other power-operated valves could create unacceptable results on overall reliability of these valves or failure to operate under design basis conditions, such as blowdown to vital areas or pump failure due to deadheading or loss of NPSH. Such failures could jeopardize other systems required to cool the core.

Possible Solution

A possible solution involved a combination of design reviews, improved surveillance/maintenance programs, valve testing, and actuation setpoint adjustments, with particular emphasis on the design basis of each power-operated valve.

PRIORITY DETERMINATION

Assumptions

The Surry, Oconee, and Sequoyah PRAs were used to model PWR AOVs and SOVs in SARA 4.0.[1456] The Grand Gulf and Peach Bottom PRAs were used to model BWR AOVs and SOVs.

Frequency Estimate

The NPRDS was used to obtain values of AOV and SOV unreliability. The results for SOVs were documented in NUREG-1275,[1079] Vol. 6, where a demand failure probability for SOVs of either 7.1×10^{-3} or 8.7×10^{-3} was given compared to a NUREG-1150[1081] value of 10^{-3}; 8.7×10^{-3} was chosen for conservatism. An AEOD analysis of NPRDS data for AOVs determined a demand failure probability of 1.1×10^{-2} for AOVs in risk significant systems and 4.2×10^{-2} for all AOVs, compared to a NUREG-1150[1081] value of 10^{-3} to 2×10^{-3}. Because of the ambiguity in the modifier "risk significant," 4.2×10^{-2} was chosen as the preferred value.

If a valve did not appear in one of the dominant cutsets for its PRA, it was assumed for these small changes in valve demand failure probability that the change in core-melt frequency would be negligible. This followed from the previous work done in the above-mentioned PRAs in which the dominant cutsets were calculated.

The intended effect of the solution was to improve the reliability of the valves to operate as designed. To reflect this, it was assumed that the solution would reduce the probability for failure of an AOV or SOV to NUREG-1150[1081] values and thus bring the core-melt frequency to the values predicted by the plant-specific PRAs. As a result, in SARA,[1456] the base case core-melt frequency value represented the value after implementation of the solution, and the adjusted case core-melt frequency represented the increased risk from including the effects of AOV and SOV unreliability. Therefore, the change in core-melt frequency computed in SARA gave the result of improving AOV and SOV reliability. The changes in core-melt frequency for the AOVs in various PRAs for both PWRs and BWRs were summarized in Table 3.158-1. However, the changes in Oconee and Surry were negligible because none of the AOVs occurred in a dominant cutset. Likewise, the changes for the SOVs in all the PRAs were negligible because none of the SOVs occurred in a dominant cutset.

Based on these findings, the Sequoyah and Peach Bottom results were chosen to be representative of all plants. Although Oconee and Surry's results were negligible and the Grand Gulf results were much less than that of Peach Bottom, choosing these two plants led to a more representative group of plants that could be vulnerable. Therefore, the change in core-melt frequency was 1.236×10^{-5}/RY and and 1.202×10^{-5}/RY for PWRs and BWRs, respectively.

Consequence Estimate

The containment failure probabilities and base consequences were taken from NUREG/CR-2800[64] for similar accident sequences. It was assumed that these results could be used for risk calculations for the Sequoyah and Peach Bottom plants. The results of the calculations for the changes in public risk, and also the

changes in core-melt frequency, are shown in Table 3.158-2. The total public risk reduction was 88,000 man-rem.

TABLE 3.158-1
Change in Core-Melt Frequency from AOV Failure Probability Changes for Various PRAs

PRA	Change in Core-Melt Frequency
PWRs	
Sequoyah, Unit 1	1.236×10^{-5}
Oconee, Unit 3	-
Surry, Unit 1	-
BWRs	
Peach Bottom, Unit 2	1.202×10^{-5}
Grand Gulf, Unit 1	1.606×10^{-7}

TABLE 3.158-2
PWR and BWR Results for Changes in Core-Melt Frequency and Public Risk

	Change in Core-Melt Frequency (per RY)	Change in Public Risk (man-rem/RY)
PWR	1.236×10^{-5}	34
BWR	1.202×10^{-5}	34

Cost Estimate

Industry Cost: Based on the experience gained from the MOV program described in Generic Letter 89-10,[1217] the average cost for the MOV implementation was estimated to be \$6M/plant. With an estimate of approximately 100 MOVs per plant, this cost was \$60,000/valve. It was assumed that a power-operated valve improvement program limited only to those AOVs, SOVs, and HOVs that contribute most to CDF would keep costs down. Based on the number of power-operated valves (20) observed to be involved in the dominant sequences, the total industry cost (OLs and CPs) was estimated to be (20)(\$60,000/plant)(111 plants) or \$133M.

NRC Cost: A study of AOVs, HOVs, and SOVs was estimated to require approximately 2 years of contractor time. NRC support of implementation of the possible solution was estimated to require additional resources. Thus, the total NRC cost was estimated to be \$3.7M.

Total Cost:The total cost associated with the possible solution was estimated to be \$(133 + 3.7)M or approximately \$137M.

Impact/Value Assessment

Based on a potential public risk reduction of 88,000 man-rem and an estimated cost of $137M for the possible solution, the impact/value ratio was given by:

$$R = \frac{\$137M}{88{,}000 \text{ man-rem}}$$

$$= \$1{,}557/\text{man-rem}$$

CONCLUSION

Based on observed escalating costs associated with the MOV program (Generic Letter 89-10),[1217] the actual cost to implement the solution to this issue could be higher than that estimated. However, it was believed that a valve improvement program limited only to those AOVs, SOVs, and HOVs that contributed the most to risk could keep costs close to the level assumed in this analysis. In addition, for CDF>10^{-5}, a medium priority was appropriate, regardless of cost. Therefore, based on the impact/value ratio and the potential risk reduction, this issue was given a MEDIUM priority ranking. In accordance with the RES evaluation,[1564] the impact of a license renewal period of 20 years will be considered in the resolution of the issue.

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1079. NUREG-1275, "Operating Experience Feedback Report," U.S. Nuclear Regulatory Commission, (Vol. 1) July 1987, (Vol. 2) December 1987, (Vol. 3) November 1988, (Vol. 4) March 1989, (Vol. 5) March 1989, (Vol. 5, Addendum) August 1989, (Vol. 6) February 1991, (Vol. 7) September 1992, (Vol. 8) December 1992, (Vol. 9) March 1993.

1081. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Vol. 1) December 1990, (Vol. 2) December 1990, (Vol. 3) January 1991.

1217. NRC Letter to All Licensees of Operating Plants and Holders of Construction Permits for Nuclear Power Plants, "Safety-Related Motor-Operated Valve Testing and Surveillance (Generic Letter No. 89-10) - 10 CFR 50.54(f)," June 28, 1989, (Supplement 1) June 13, 1990, (Supplement 2) August 3, 1990, (Supplement 3) October 25, 1990, (Supplement 4) February 12, 1992.

1456. NUREG/CR-5303, "System Analysis and Risk Assessment System (SARA) Version 4.0," U.S. Nuclear Regulatory Commission, (Vol. 1) February 1992, (Vol. 2) January 1992.

1481. Memorandum for E. Beckjord from T. Murley, "Potential New Generic Issues," September 25, 1991.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 159: QUALIFICATION OF SAFETY-RELATED PUMPS WHILE RUNNING ON MINIMUM FLOW

DESCRIPTION

Historical Background

This issue was identified[1481] by NRR and addressed concerns involving centrifugal pumps operating at some point below the best efficiency point (BEP) on their characteristic curves that could cause hydraulic instability or flow recirculation inside the pumps. This unstable flow phenomenon becomes progressively more pronounced as the flow is further decreased and could result in pump damage from vibration and recirculation cavitation (voids created by the recirculating current).

On May 24, 1986, Susquehanna Unit 1 experienced an event (LER 86-021-00) involving pump damage due to erosion caused by recirculation cavitation during partial flow operation of an ESW pump. An inspection of all other ESW pumps revealed similar cavitation damage. The licensee estimated that cavitation occurred when the pumps ran at a flow rate significantly lower than the design rate. Because they were of similar design, the RHR service water pumps were also inspected and cavitation damage was found on the impeller liners.

In a search of an operational data base for the period from 1983 to 1988, four additional events involving either pump failure or potential for pump degradation resulting from low flow operation were found. These events occurred at Vermont Yankee, H. B. Robinson 2, Turkey Point 3, and Haddam Neck, and were reported in AEOD/E807.[1488]

In 1988, W issued notices to all of its NSSS users regarding minimum flows for thermal protection (thermal) and long-term protection (mechanical minimum flow) in all postulated scenarios (including design basis accident conditions) anticipated during the lifetime of all safety-related pumps including the RHR, HPSI, Core Spray, and AFW pumps. Based on the operating events and the W notification, the NRC issued Bulletin No. 88-04[1489] requesting licensees to take actions to deal with the concerns involving centrifugal pumps operating at low flow conditions. Two areas of concern were discussed in the bulletin:

(1) When two centrifugal pumps operate in parallel and one of the pumps is stronger than the other (i.e., it has a higher developed head for the same flow), the weaker pump may be dead-headed when the pumps are operating in the minimum flow mode. The phenomenon is manifested at low flow rates because of the flatness of the pump characteristic curve in this range. The head difference is not a problem at moderate to high flow conditions because of the shape of the pump characteristic curve in these regions.

(2) In the past, the required minimum flow for these pumps was established solely from the temperature rise in the pumped fluid. However, it became generally understood that temperature rise is the only factor that can influence safe, continuous, minimum flow operation. Centrifugal pumps will demonstrate a flow condition that

is described as hydraulic instability or impeller recirculation at some point below the BEP on their characteristic curves. These unsteady flow phenomena become progressively more pronounced as the flow is further decreased and can result in pump damage from vibration, excessive forces on the impeller, and cavitation.

The above first concern pertaining to dead-heading of pumps was not included in the NRR memorandum.[1481] This concern was considered resolved by actions licensees took to either: (1) install an additional bypass line; (2) replace the existing line with a larger bypass line; or (3) change the operational procedures to prevent the potential of a pump being dead-headed. However, licensee responses dealing with the second concern were not completely satisfactory to NRR.[1481]

Safety Significance

This issue was concerned with the operability of pumps in all safety-related systems that are addressed in GDC 34 (RHR Heat Removal), GDC 35 (Emergency Core Cooling), GDC 38 (Containment Cooling), and GDC 44 (Cooling Water Supply) of Appendix A to 10 CFR 50; these cooling functions are vital for reactor or containment protection.

Solution

Bulletin No. 88-04[1489] identified several action items and associated general guidance. Specifically, Action Item 3 requested each licensee to evaluate the potential pump damage caused by low flow operation and testing. The guidance for conducting the evaluation included consideration of the effects of cumulative operation during the postulated accident scenario and testing during the plant life, the use of test data and field experience data, and verification of the pump supplier's recommended minimum flow rate. Action Item 4 requested licensees to identify, if needed, the short-term and long-term modifications to plant operating procedures or hardware changes to mitigate the problems.

Licensee responses to Bulletin No. 88-04[1489] were reviewed by ORNL and the results were summarized in NUREG/CR-5706.[1490] ORNL indicated that the level of information provided in the licensee responses varied substantially. Some plants provided fairly detailed discussions of original and existing minimum flow recommendations and system configurations, as well as an identification of specific design, procedural, or other changes made in response to the bulletin. However, a number of responses provided only an indication that the concerns had been reviewed, with little or no system/pump-specific information provided.

There were 29 PWRs (at 18 sites) that identified a total of 56 procedure changes and 38 design modifications made in response to Bulletin No. 88-04.[1489] There were 8 BWRs (at 6 sites) that identified a total of 17 procedure changes and 6 design modifications. In addition to design or procedure changes, special tests and analyses performed in conjunction with the bulletin were identified. The ORNL findings were: (1) there were no generic guidelines for determining the acceptability of a pump's mission time for various modes of operation; and (2) some licensee responses did not adequately address the low flow concern. Therefore, ORNL recommended that the industry be encouraged to develop pump qualification criteria and new diagnostic techniques for pump testing.

NRR reviewed some responses to Bulletin No. 88-04[1489] to determine if additional guidance was needed to supplement the bulletin. With respect to the concern of pump mission time for all anticipated operational modes, NRR concluded that "... Rather than performing detailed accident analyses to determine the longest possible time which a pump could be called upon to run, licensees have modified procedures or made physical modifications to preclude low flow operation outside the range recommended by the vendor." Some licensees have relied on this approach to deal with the low flow problems and the staff found this approach reasonable and acceptable.[1491]

Following the issuance of Bulletin No. 88-04,[1489] NRC Temporary Instruction 2515/105 was used to conduct inspections to ensure adequate licensee response to the bulletin and to ensure that safety-related pumps would not be damaged during minimum flow operation or testing. Twelve plants (PWRs and BWRs) were selected for the inspection that was completed in September 1991. Although there were some weaknesses in the licensee responses, the inspection found them adequate, except for a few plant-specific open items that were expected to be resolved before the next refueling outage at each of the selected plants. MPA-X804 was established by NRR to track licensee implementation of Bulletin No. 88-04.[1489]

The Nuclear Plant Aging Research Program,[1492] which included the pumps of concern in this issue, was expected to investigate the cumulative effect of low flow operation and testing on pump aging and provide additional insights for future considerations.

CONCLUSION

The conclusions[1491] of the staff and the ORNL review[1490] of responses to Bulletin 88-04[1489] indicated that, in general, the concerns involving pump operation under low flow conditions had been addressed by most licensees. For the areas that remained to be resolved, the ORNL insights and recommendations were expected to be accommodated within the context of the bulletin. The follow-up inspection of 12 plant sites with 20 units turned up no apparent damage to the pumps inspected. The actions taken by the licensees in response to the bulletin were expected to improve the reliability of pumps under low flow operation. Therefore, the safety concerns of this issue were previously addressed by the staff with the issuance of Bulletin No. 88-04[1489] and the issue was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

1481. Memorandum for E. Beckjord from T. Murley, "Potential New Generic Issues," September 25, 1991.

1488. Memorandum for E. Jordan from T. Novak, "Engineering Evaluation Report - Pump Damage Due to Low Flow Cavitation (AEOD/E807)," October 18, 1988.

1489. NRC Bulletin No. 88-04, "Potential Safety-Related Pump Loss," U.S. Nuclear Regulatory Commission, May 5, 1988.

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1491. Memorandum for J. Norberg from R. Jones, "Review of Responses to Bulletin 88-04," July 22, 1991.

1492. NUREG/CR-5404, "Auxiliary Feedwater System Aging Study," U. S. Nuclear Regulatory Commission, (Vol. 2) July 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 160: SPURIOUS ACTUATIONS OF INSTRUMENTATION UPON RESTORATION OF POWER

DESCRIPTION

Historical Background

This issue was raised[1481] by NRR following a review of events at 3 operating BWR plants that involved inadvertent ESF actuations upon loss and subsequent restoration of power to Rosemount analog transmitter trip units (ATTUs). NRC Information Notice No. 90-22[1528] was issued to alert OLs and CPs of this concern.

Equipment response to loss and restoration of power would normally be a design consideration for equipment and control system designers. As such, there was no specific NRC guidance for re-energizing instrumentation that may be inadvertently de-energized. Except for the Information Notice,[1528] there had been no communication from the NRC, between licensees and vendors, or among utilities regarding this potential problem and its possible corrective actions. This issue addressed inadvertent actuation of any equipment upon restoration of power and was not limited to equipment actuated by Rosemount ATTUs. Thus, the scope of this issue was broader than that addressed in the Information Notice.[1528]

Safety Significance

The concern of this issue was the effects of restoration of power to safety-related equipment that is normally energized but which inadvertently loses power. The effect of restoration of power might not be as thoroughly analyzed as the effect of a loss of power. In many plants, safety-related instrumentation is powered from interruptible buses because of the "fail safe" response of the instrument upon the loss of power. However, the response of these instruments to a restoration of power may be undesirable or could lead to risk significant events.

The main concern raised by NRR was that these events had the potential for initiating an ISLOCA and/or low temperature overpressurization (a LTOP event) by improper actuation of MOVs. NRR believed[1481] that there was a need to evaluate the effects of re-energizing of instruments on a broader scale than was done for the operating events experienced. For instance, although all of the events occurred in BWRs that have analog trip units manufactured by Rosemount, a potentially significant risk exists if single channel interlocks are used in valve circuits, or single channel permissives are used regardless of the type of reactor involved. Similarly, a potentially significant risk exists if multiple channels are subjected to a loss of power at the same time (e.g., loss of offsite power) and subsequently re-energized with power available to the actuated equipment before the control logic is reset.

Possible Solutions

Any resolution to this issue should address the potential for inadvertent ESF actuations upon loss and restoration of power. In particular, the inadvertent opening of PIVs and the corresponding increased risk of ISLOCA and LTOP accident sequences should be considered. The following were possible solutions:

(1) Improve ATTU power supply reliability.

(2) Improve operator training and procedures to respond to ISLOCA and LTOP events.

(3) Improve the design of power supplies and ESF actuation circuitry so that spurious actuation of valves or pumps does not occur upon restoration of power.

(4) Implement auctioneering circuit from two ATTU voltage converters, one converter taking input from a 120V AC instrument bus and the other converter taking input from a 125V DC source.

(5) Use a diverse interlock for PIV opening, e.g., use a contact from the RHR pump motor breaker to signal that the RHR pump is running.

PRIORITY DETERMINATION

Assumptions

The concern stated by NRR involved the potential effects from misoperation of equipment upon restoration of power and was not limited to cases involving the Rosemount ATTUs identified in Information Notice No. 90-22.[1528] Two accident sequences were identified by NRR that could result from spurious actuation of equipment due to loss and restoration of power. These were ISLOCA and LTOP resulting from spurious actuation of MOVs, both of which had been studied previously by the NRC.

The regulatory analysis[1501] for the resolution of Issue 105 presented the results of a cost benefit analysis for proposed actions to resolve the concern regarding ISLOCA. The resolution of Issue 105 fell within the scope of that proposed for Issue 160, thus permitting use of relevant information from NUREG-1463.[1501] Based upon the results of this cost benefit analysis, the recommended resolution for Issue 105 was to perform plant-specific reviews for ISLOCA vulnerabilities in conjunction with the IPE program.

One of the recommended actions in NUREG-1463[1501] for decreasing the risk of ISLOCA was to perform a leak test of the pressure isolation check valves between the LPCI system and the high pressure RCS by cycling open any normally-closed MOVs upstream from these valves at least once per year, because latent failure of these check valves could result in ISLOCA upon opening of the normally-closed MOV. This action would reduce the initiating event frequency for ISLOCA to 2.5×10^{-7}/RY for any plant that utilizes a valve configuration with a normally-closed MOV upstream from two check valves. Based upon the events reported in Information Notice No. 90-22[1528] and a review of LERs, the frequency of spurious actuation of these MOVs due to an inadvertent SI signal resulting from the loss and restoration of power was approximately 5×10^{-3} event/RY. This value was about 10% of the assumed frequency of inadvertent SI (6.4×10^{-2}/RY) reported in NUREG/CR-5102,[1500] the source of the analysis in NUREG-1463.[1501] Therefore, the decrease in initiating event frequency that could be realized by preventing spurious actuation of these MOVs upon loss and restoration of power would be approximately 2.5×10^{-8}/RY, which was not a significant decrease.

Some plants cycle the MOVs between the LPCI system and the RCS as frequently as once per month during full power operation; Calvert Cliffs 1 is one such example.[1500] These plants would gain little benefit from preventing an additional spurious actuation with a frequency of 5×10^{-3}/RY. In addition, MOVs at the interface between the LPCI system and the RCS for many PWRs are normally open such that a spurious LPCI actuation signal would not inadvertently open these valves. Based upon the results of Issue 105, it was concluded that there was no significant potential for spurious actuation of MOVs to cause an ISLOCA.

Using relevant information from NUREG-1326[1291] (the regulatory analysis for Issue 94), the solutions to Issues 94 and 160 are consistent with each other. Implementation of the resolution of Issue 94 (see Generic Letter 90-06) would reduce the mean CDF for LTOP events from 3.24×10^{-6} to 3.5×10^{-7} event/RY. It was assumed in this analysis that elimination of all spurious actuations upon restoration of power would result in the elimination of the remaining risk from LTOP events. This was a conservative assumption because BWRs are not at risk from LTOP.

In order to determine if any other events that involved the misoperation of equipment upon restoration of power had occurred, a search of the Sequence Coding and Search System (SCSS) database was conducted. This ORNL database contained data from over 35,000 LERs reported after 1980. The search identified 198 events that involved the spurious actuation of pumps or valves upon loss and restoration of power. It was assumed that any significant events that occurred since 1980 would be identified by the SCSS search; however, it was noted that the results of the SCSS search did not include the 3 events reported in Information Notice No. 90-22.[1528] The most likely explanation for this fact was that the 3 events did not involve a loss and restoration of power, but instead were caused by an increase in voltage above the trip setpoint of the trip units. The SCSS search was still quite relevant, because the concern stated by NRR involved the effects of loss and restoration of power to all equipment, whereas the problem identified in the Notice[1528] resulted from the unique characteristics of the Rosemount ATTUs.

The review of these events did not reveal any additional concerns. Eight of the 198 LERs involved spurious actuation of equipment upon restoration of power; these are listed in Table 3.160-1. Six of these eight events involved systems operating as designed and were resolved by specifying correct test or maintenance procedures. The seventh event involved the concurrent failure of an electronic controls component with restoration of power. This component likely failed prior to loss and restoration of power as a second replacement component was also failed prior to installation. The eighth event involved a pressure signal spike because of a dead bus transfer and was resolved by rewriting procedures to avoid dead bus transfers. These events involved failure to consider available design and performance criteria of equipment during the systems design and in the specification of maintenance or test procedures. In addition, none of these events resulted in system responses that were significant accident sequence precursors.

None of the spurious actuations involved the ISLOCA sequence initiating event described earlier (opening of normally-closed MOV upstream from pressure isolation check valves). Based upon the 3 events reported in Information Notice No. 90-22[1528] that occurred during the 6-year period from 1984 to 1990 and involved de-energization of Rosemount ATTUs due to overvoltage, the ISLOCA

initiating event frequency resulting from this concern was approximately 5 x 10^{-3} event/RY (3 events in approximately 600 RY).

TABLE 3.160-1
Spurious Actuation of Equipment Upon Restoration of Power

Event	Number of Occurrences
Reactor Trip	1
Decay Heat Cooler TS Violation	1
MSIV Opened/Closed	2
RHR Suction Valve closure	1
ESFAS Actuation	1
Partial SI Actuation	1
Accumulator Valve Opened During Shutdown	1

Because this review did not reveal any additional areas of concern, this analysis was limited to the ISLOCA and LTOP events identified.[1481] Although it was possible that other events had occurred that were not identified in this SCSS search, such events were either not clearly caused by the loss and restoration of power or did not involve an event precursor of significant frequency or severity. Hence, a review of operational history showed that, not only were inappropriate responses to power restoration rare, but such responses did not appear to cause significant problems.

It was assumed that 74 PWRs and 37 BWRs with average remaining lives of 24.7 years and 23.3 years, respectively, would be affected by the resolution of this issue. The cost estimates for this issue were taken mainly from NUREG/CR-4627[961] and NUREG/CR-2800.[64]

Frequency Estimate

As discussed above, the base case included the implementation of all recommendations from the resolution of Issue 94. Although there was some risk remaining from ISLOCA after implementation of the recommendations in Issue 105, this risk would not be significantly mitigated by reduction of the frequency of spurious actuation of equipment due to loss and restoration of power. No other significant event precursors were identified from the review of the 198 LERs identified by the SCSS relating to inadvertent equipment actuation.

The estimated decrease in CDF that could result from resolution of this issue was the CDF remaining after implementation of the recommended actions for Issue 94. The remaining risk for LTOP events after implementation of the recommended resolution of Issue 94 was assumed to be the potential safety benefit from the resolution of this issue.

The remaining CDF after implementation of the resolution of Issue 94 was 3.5 x 10^{-7} event/RY. It was assumed that resolving this issue would result in a decrease in CDF of 3.5 x 10^{-7} event/RY. This estimate included safety benefits that would not be realized by the resolution of the issue, such as CDF reduction in BWRs which are not susceptible to the LTOP event. Thus, for the 111 affected

plants, it was estimated that the total CDF reduction from resolution of the issue would be 3.89×10^{-5} event/year.

Consequence Estimate

A dose of 4.5×10^{6} man-rem/event was given in NUREG/CR-5186[1527] for PWRs and BWRs. Based on an average remaining operating life of 24.2 RY for the affected plants, the estimated total public risk reduction was $(3.89 \times 10^{-5})(24.2)(4.5 \times 10^{6})$ man-rem or 4,230 man-rem.

Cost Estimate

Industry Cost: Implementing the possible solution consisted of two parts. The first part was the cost of labor for training and installation of new equipment/components due to modification and was estimated to be 2 man-years/plant. Assuming all the modification and installation could be done during a scheduled plant outage, no replacement power costs were included. The second part was the equipment/component costs estimated to be $200,000/plant. Labor requirements to perform the enhanced training and inspection program were assumed to be integrated with or to replace existing programs. Therefore, no additional labor was assumed for operation and maintenance of the solution. Using the labor rate of $100,000/man-year from NUREG/CR-2800,[64] the total industry cost for implementation of the possible solution at 111 plants was estimated to be $45M.

NRC Cost: Development of the proposed solution was estimated to require 24 man-months to further evaluate the issue, develop a resolution, and perform a regulatory analysis. Using the referenced[64] labor rate, the cost for development of the resolution was estimated to be $200,000. The cost to support its implementation was estimated to be 1 man-week/plant, for an additional cost of $210,000. The labor for review of operation and maintenance of the possible solution was estimated to be 1 man-day/RY, for an additional cost of $1M. Thus, the total NRC cost was estimated to be $1.4M.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $(45 + 1.4)M or $46.4M.

Impact/Value Assessment

Based on a total potential public risk reduction of 4,230 man-rem and a cost of $46.4M, the impact/value ratio was given by:

$$R = \frac{\$46.4M}{4{,}230 \text{ man-rem}}$$

$$= \$10{,}969/\text{man-rem}$$

Other Considerations

(1) It was estimated that utility labor in radiation zones would be required for installation of new equipment. A total of 3 man-weeks/plant were estimated and a 75% utilization factor was assumed for labor in radiation zones. It was further assumed that the dose rate in the radiation zones was 100 millirem/hour. With 111 plants, this ORE increase was 1,000 man-rem.

(2) It was assumed that one additional man-week of utility labor in radiation zones would be required for examination of equipment installed or exchanged as a result of the resolution. Assuming a 75% utilization factor, the incremental labor in radiation zones for operation and maintenance was estimated to be 30 man-hours/RY. Using the estimated 2,690 remaining operating years, the total increase was 6,100 man-rem. Thus, the total ORE associated with the possible solution was 7,100 man-rem.

CONCLUSION

Based on the overall consideration of the backfit solution for operating plants, this issue was placed in the DROP category. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period would only move the issue to a low priority ranking.

REFERENCES

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

889. NSAC-60, "A Probabilistic Risk Assessment of Oconee Unit 3," Electric Power Research Institute, June 1984.

961. NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986, (Rev.1) February 1989, (Rev.2) February 1992.

1291. NUREG-1326, "Regulatory Analysis for the Resolution of Generic Issue 94, 'Additional Low-Temperature Overpressure Protection for Light-Water Reactors," U.S. Nuclear Regulatory Commission, December 1989.

1481. Memorandum for E. Beckjord from T. Murley, "Potential New Generic Issues," September 25, 1991.

1500. NUREG/CR-5102, "Interfacing System LOCA: Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, February 1989.

1501. NUREG-1463, "Regulatory Analysis for the Resolution of Generic Safety Issue 105: Interfacing System Loss-of-Coolant Accident in Light-Water Reactors," U.S. Nuclear Regulatory Commission, July 1993.

1527. NUREG/CR-5186, "Value/Impact Analysis of Generic Issue 94, 'Additional Low Temperature Overpressure Protection for Light Water Reactors,'" U.S. Nuclear Regulatory Commission, November 1988.

1528. NRC Information Notice No. 90-22, "Unanticipated Equipment Actuations Following Restoration of Power to Rosemount Transmitter Trip Units," U.S. Nuclear Regulatory Commission, March 23, 1990.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 161: USE OF NON-SAFETY-RELATED POWER SUPPLIES IN SAFETY-RELATED CIRCUITS

DESCRIPTION

This issue was identified[1481] by NRR to address the concerns raised during the licensing of Nine Mile Point Unit 2.

On February 7, 1985, Niagara Mohawk submitted to the NRC a report on "Non-Class 1E Devices Connected to Class 1E Power Supplies" which stated that "the non-Class 1E devices to be analyzed were identified by a study of Elementary Diagrams and Elementary Diagram Device Lists for all safety systems in the GE scope of supply for NMP2." These devices were asserted to be acceptable by the licensee and the vendor (GE) based on an FMEA; however, this FMEA was not accepted by the staff. Ultimately, of the 239 identified components, 35 were isolated with qualified isolation devices and 76 were upgraded to Class 1E by the licensee in order to meet the regulatory requirements imposed by the staff.

The fundamental concern in this issue was whether the staff's actions in requiring the isolation or replacement of 111 out of 239 components during the licensing review was a change in regulatory position and, if so, whether the position should be backfit to all licensed facilities. The position taken by the staff in 1985 during the OL review of Nine Mile Point 2 was necessary to meet the regulations in effect at that time. It was GE's contention that the design approach at Nine Mile Point 2 was similar to that used at other plants and was accepted by the NRC during the licensing review of BWR plants.

The determination of whether a component or system is an associated circuit is based on the application of IEEE 384-1977 and IEEE 279-1971. Any non-Class 1E component or system which interconnects with a Class 1E component or system is an associated circuit, unless it is adequately isolated. IEEE 279-1971, which was incorporated by reference into 10 CFR 50.55a(h), does not identify associated circuits but only states that "the transmission of signals from protection system [Class 1E] equipment for control system [non-Class 1E] use shall be through isolation devices which shall be classified as part of the protection system." This restriction was relaxed in IEEE 384-1977 to define an associated circuit as any circuit comprised of non-Class 1E components that is not isolated from a Class 1E circuit by an isolation device. This configuration is acceptable if the associated circuit is "analyzed or tested to demonstrate that Class 1E circuits are not degraded below an acceptable level." IEEE 384-1977 was adopted in Regulatory Guide 1.75, Revision 3, in September 1978.

CONCLUSION

Prior to the publication of IEEE 384, the classification of an associated circuit did not exist and any non-Class 1E component should have been isolated from a Class 1E component or system by a qualified isolation device. Therefore, it was unlikely that the staff accepted a practice in the past which they found unacceptable in 1985, since the requirements in 1985 were less strict than the requirements before 1977. GE was unable to document previous acceptance by the staff of the design practice under contention. In addition, the criteria used by the staff in 1985 to determine whether a circuit is an associated circuit and

whether the associated circuit should be isolated would also be applied currently to OL applicants.

The components at Nine Mile Point 2 were analyzed by GE and resulted in 128 of the 239 identified components being accepted as associated circuits without modification; however, the remaining 111 components were upgraded to Class 1E or were isolated. It appears reasonable to assume that the determination made by NRR regarding the need for components to be Class 1E is correct. Thus, this issue was determined to be a matter of compliance with existing regulations[1482] and was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

1481. Memorandum for E. Beckjord from T. Murley, "Potential New Generic Issues," September 25, 1991.

1482. Memorandum for T. Murley from E. Beckjord, "Prioritization of Generic Issue 161, 'Associated Circuits,'" March 12, 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 162: INADEQUATE TECHNICAL SPECIFICATIONS FOR SHARED SYSTEMS AT MULTIPLANT SITES WHEN ONE UNIT IS SHUT DOWN

DESCRIPTION

Historical Background

This issue was identified[1481,1553] by NRR as a result of a diagnostic evaluation team inspection of the SWS at Zion, a multiplant site. The inspection identified the potential for some additional shared systems to have an inadequate number of available components or inadequate flow rates when one unit is shutdown and the other unit is operating. The staff concluded that these inadequacies at Zion were due both to the existing TS and to the licensee's poor understanding of the original design basis. Since the staff's concerns with the SWS were already being addressed as part of the resolution of Issues 130 and 153, no additional generic follow-up of the SWS concerns was conducted.

NRR identified the following systems as having the potential for inadequate TS when they are shared: (1) HVAC systems for shared control room areas and switchgear rooms; (2) onsite AC and DC systems; and (3) the CCW system. From the total of 39 multiplant sites in the U.S., updated FSARs for 10 sites (7 PWRs and 3 BWRs) were selected for review to determine the extent of sharing of these systems and to assess the potential impact of TS on the adequacy of this sharing. This review, along with a review of applicable Bulletins, Information Notices, and Generic Letters, resulted in the following observations:

(1) The CCW system is generally not shared. At BWRs, it is not a safety-related system and is not addressed in the TS. For most PWRs, this system is not normally shared because it is a closed system with separate surge tanks for each train and cross-connected operation can be difficult. Although the CCW system is shared at Surry 1 & 2, Zion 1 & 2, and D. C. Cook 1 & 2, any plant-specific vulnerabilities were to be identified in the IPE program. In addition, calculations in the generic shutdown study indicated that one of the above 3 PWR sites was examined and showed that the CDF contribution of CCW system failures during shutdown was relatively small (about 4×10^{-6} /RY). Therefore, the staff concluded that the CCW system did not warrant additional generic review to determine if TS are adequate for those shared CCW systems.

(2) The HVAC system for common control room areas is required to be operable in all modes so that the operating mode of one unit does not affect the operability of the other unit's HVAC system. Preliminary estimates[64] of the CDF resulting from loss of cooling to the control room for a typical PWR and BWR would be about 7×10^{-7}/RY and 2×10^{-7}/RY, respectively. In addition, control room HVAC systems were reviewed under Issue 143. Consequently, it was concluded that the HVAC system for common control room areas did not warrant additional generic review.

(3) The design of HVAC systems servicing non-control room areas (e.g., switchgear rooms) is plant-specific and required examination by licensees as part of the IPE program to identify plant-specific vulnerabilities. This study indicated that, although the switchgear room is the most important non-control room area, the CDF resulting from loss of room cooling for a typical PWR or BWR would not be large (about 10^{-6}/RY and 10^{-7}/RY, respectively). In addition, calculations[64] indicated that one of the above PWR sites was evaluated and showed that the CDF contribution of failed HVAC in switchgear rooms was negligible (about 1.2×10^{-7}/RY). Also, HVAC systems were reviewed under Issue 143. Therefore, it was concluded that the adequacy of TS associated with HVAC systems for non-control room areas did not warrant additional generic review.

(4) Onsite AC and DC systems for multiplant sites are generally physically and electrically separated and redundant and are rarely shared between units. Special inspections for the AC and DC systems identified some plant-specific issues at some multiplant units and were addressed. The objective of these special inspections was to assess the performance capability of the electrical distribution system to adequately support the operation of the licensees' safety-related components. These systems were reviewed under the station blackout program and licensees were also expected to identify vulnerabilities associated with AC and DC systems in the IPE program. Therefore, it was concluded that the adequacy of TS associated with shared onsite AC and DC systems did not warrant further generic review.

(5) The Maintenance Rule, 10CFR 50.65(a)(3), requires that, in performing monitoring and preventive maintenance activities, an assessment of the total plant equipment that is out of service be taken into account to determine the overall effect on performance of safety functions. It was expected that this assessment would provide additional assurance that an adequate number of shared components will be available at multiplant sites.

CONCLUSION

The staff concluded that the concerns raised with the adequacy of TS associated with shared CCW systems, common control area HVAC, shared switchgear room HVAC, and onsite AC and DC systems had been or will be addressed by existing programs or activities. Therefore, this issue was DROPPED from further consideration as a new and separate issue. In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

1481. Memorandum for E. Beckjord from T. Murley, "Potential New Generic Issues," September 25, 1991.

1553. Memorandum for A. Gody from G. Holahan, "Prioritization of Proposed Generic Issue 162, 'Inadequate Technical Specifications for Shared Systems at Multi-plant Sites When One Unit Is Shut Down,'" March 20, 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 164: NEUTRON FLUENCE IN REACTOR VESSEL

DESCRIPTION

To calculate the value of RT_{PTS} as required in 10 CFR 50.61 and 10 CFR 50, Appendix G, licensees must determine the value of the fast neutron fluence on the inside surface of their pressure vessels. Through a number of reviews, NRR found[1515] a non-conservative computational bias in the W methodology which, in one instance (Yankee Rowe), was determined to be 13%, while in WCAP-11815 (Indian Point 3 Surveillance Capsule Z Report) it was reported to be 20%. Several publications suggest that the iron inelastic scattering cross-sections in ENDF/B-VI yield higher fluence values for transmissions through iron; thus, ENDF/B-IV (currently in use) may not be conservative.

Licensees are required to determine applicable uncertainties in the measurements and calculations for reactor cavity dosimetry. In Regulatory Guide 1.99,[841] Revision 2, the staff assumed a fluence uncertainty of 20% in determining trend curves. Thus, this level of uncertainty at the inside surface of the pressure vessel should be supported. The bias in the W calculations may exist in other vendor or licensee methodologies, or it may pertain to the iron cross-sections. Thus, the staff believed that this issue could affect all PWRs.

CONCLUSION

The safety concern of this issue is being addressed in the Surveillance Data Base, Analysis, and Standardization Program (FIN B04152). Concurrent with this program, the staff developed Draft Regulatory Guide DG-1025, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." Thus, the issue was DROPPED from further consideration as a new and separate issue.[1516] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not change the priority of the issue.

REFERENCES

841. Regulatory Guide 1.99, "Effects of Residual Elements on Predicted Radiation Damage to Reactor Vessel Materials," U.S. Nuclear Regulatory Commission, July 1975, (Rev. 1) April 1977, (Rev. 2) May 1988.

1515. Memorandum for E. Beckjord from T. Murley, "Proposed New Generic Issue: 'Determination of Neutron Fluence to Pressure Vessels,'" October 8, 1992.

1516. Memorandum for T. Murley from E. Beckjord, "Proposed New Generic Issue: Determination of Neutron Fluence to PWR Pressure Vessels," November 30, 1992.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 165: SPRING-ACTUATED SAFETY AND RELIEF VALVE RELIABILITY

DESCRIPTION

Historical Background

This issue was identified[1520] by NRR when it was found that, on a number of occasions, licensees reported that spring-actuated safety and relief valves failed to meet setpoint criteria within the desired tolerance. Other reported incidents included more seriously degraded performance of safety and relief valves. These events were documented in AEOD/S92-02[1556] in which the staff concluded that most pressurizer safety valves (PSVs), main steam safety valves (MSSVs), and BWR safety/relief valves (SRVs) did not meet the 1% setpoint drift tolerance and many were above 3%. These results suggested that other systems with safety and relief valves could be adversely affected by setpoint drift. The staff discussed some of these systems in Information Notices 90-05[1557] and 92-64[1558] and in NUREG/CR-6001.[1560] More importantly, at Shearon Harris, the failure of a high head safety injection RV to operate at a very low setpoint resulted in the undetected loss of the entire system and would have resulted in inadequate emergency core coolant injection if a small- or intermediate-break LOCA had occurred. This event was discussed in detail in LER 91-008-01 and Information Notice 92-61.[1559]

Spring-actuated safety and relief valves provide overpressure protection for a number of systems in both PWRs and BWRs. However, failure of these valves in safety-related support systems could cause a significant diversion of flow from these systems and thus prevent the systems from performing their designed function. It was estimated that perhaps 3 to 5 (out of a total of 55 to 60) spring-actuated safety and relief valves installed in such safety-related systems of a typical PWR or BWR plant could be significant contributors to core-melt frequency. Also, due to the size of these valves (<4 inches), it was believed that most of them could be tested at the plant site (many of them in situ), thus reducing the time and cost for testing. For these reasons, this issue addressed the unreliability of spring-actuated safety and relief valves in safety-related support systems.

Although Issue B-55 addressed the reliability of Target Rock two-stage pilot-operated SRVs and Issue 70 addressed the reliability of PORVs and block valves, there was no generic issue for spring-actuated SVs and RVs. Because significant NRC and industry resources had been spent in the past on both evaluating the risk and improving the reliability of PSVs, PORVs, MSSVs, and BWR SRVs, the focus of this issue was limited to spring-actuated RVs in safety-related support systems and the effects of their unreliability on plant operation.

Safety Significance

Failure of a spring-actuated relief valve can lead to a core-melt from loss of core cooling and inventory makeup. Possible sources of loss include: (1) failure of a valve to close after opening; (2) failure of a valve to open when

challenged, resulting in overpressure conditions that precipitate a LOCA; and (3) premature opening of a valve below setpoint resulting in a LOCA.

Possible Solution

A possible solution was to improve the periodic inspection and testing of spring-actuated RVs in risk-significant systems.

PRIORITY DETERMINATION

Assumptions

It was assumed that 71 operating plants with a combined remaining life of 1,907 RY were affected by the issue: 47 PWRs and 24 BWRs with average remaining lives of 27.7 and 25.2 years, respectively. (This corresponded to the number of plants existing or planned at the time of the initial publication of NUREG/CR-2800.[64]) Implementation of the solution could be achieved at future plants with minimal incremental costs and, thus, a forward-fit evaluation was not performed.

Failure of an RV to operate within the allowable opening and closing setpoints was considered a failure of the valve. However, not all valve failures necessarily fail the train of the system in which they operate. Therefore, it was conservatively assumed that 10% of the valve failures would fail their trains. NPRDS was used to obtain values of RV unreliability for various systems throughout a plant with spring-actuated RVs. From these data, a best estimate probability of the RV to fail its train was calculated to be 5×10^{-3} /demand (based on 524 valve failures out of 10,063 events multiplied by a 10% train failure probability). The upper bound probability was 5×10^{-2} /demand, assuming the RV failure always resulted in train failure. A lower bound probability was estimated by using the AEOD report[1556] which considered 9 valve failures out of 1100 events, equaling a probability of 10^{-3}/demand including the 10% train failure probability.

Frequency Estimate

The Surry PRA[1318] was used to model PWR RVs in SARA 4.0,[1456] the Grand Gulf PRA[1318] was primarily used to model BWR RVs, and the Peach Bottom PRA[1318] was used to support the Grand Gulf results.

Because the Surry PRA did not include RVs in every system, modifications to the PRA were required to model their effects on a particular system. For those systems where RVs were included with a component in a single train whose unavailability could fail the entire system, the failure probability of the RV was added to the component's failure probability. On the other hand, for those systems where RVs were included with components in 2 trains where common mode failure could occur, the failure probability of the RV had to be added by taking into account the use of beta factors in the component's failure probability. A beta factor was defined as the conditional probability of a component failure given that a similar component has failed. P (the component failure probability including the RV reliability) and β (the beta factor for the RV and component) were given by $P = (P_c + P_v)$ and $\beta = [(\beta_c P_c + \beta_v P_v)/(P_c + P_v)]$, where β_c and β_v were the beta factors and P_c and P_v were the failure probabilities for the component and RV, respectively. In this analysis, a value of 7×10^{-2} was used for β_v which was obtained from the beta factor for an SRV in the PRA. The values of β_c and P_c

were obtained from the applicable component in the PRA. Using the above equations, the values of P and β were calculated and then inserted into SARA for those systems that had dual trains.

The effect of the solution would be to improve the reliability that the valves operate as designed. To reflect this, it was assumed that the solution would reduce the probability for a failure of a safety or relief valve to a negligible amount and thus bring the core-melt frequency to the values predicted by the plant-specific PRAs. As a result, in SARA the base case core-melt frequency value represented the value after implementation of the possible solution and the adjusted case core-melt frequency represented the increased risk from including the effects of safety and relief valve unreliability. Therefore, the change in core-melt frequency computed in SARA gave the result of improving safety and relief reliability. The changes in core-melt frequency for various systems in the Surry PRA were summarized in Table 3.165-1. Diesel and emergency power includes RVs in the emergency diesel generator air start system (see Information Notice No. 90-18[1561]). The changes for the Component Cooling Water, Containment Spray, Main Feedwater, and Essential Service Water systems were negligible.

The significant changes in core-melt frequency for various systems in the Grand Gulf PRA were summarized in Table 3.165-2. The changes for other systems studied (which included the RHR/LPI, Feedwater, Condensate, Standby Liquid Control, Control Rod Drive, Nuclear Steam Supply Shutoff, and Low Pressure Core Spray systems) were negligible. The Peach Bottom PRA was used in SARA to further validate the change from the Essential Service Water system computed in the Grand Gulf PRA. These results supported that finding.

Consequence Estimate

The containment failure probabilities and base consequences were taken from NUREG/CR-2800[64] for similar accident sequences. The results from the per-plant calculations for the changes in public risk and core-melt frequency are shown in Table 3.165-3 for the three different estimates of valve failure probability. The total public risk reduction was 10^5 man-rem with a lower bound estimate of 2 x 10^4 man-rem and an upper bound estimate of 10^6 man-rem. These values would increase by about 50% if 75% of the plants had their licenses renewed for a 20-year period.

Cost Estimate

Industry Cost: Assuming that improved periodic inspection and testing of RV systems were required every year and could be performed in about 2 man-days, the total annual test and inspection requirements for each system was estimated to be about 2 man-days/RY. Assuming 5 affected systems per plant, the total labor would be 2 man-weeks/RY. At a cost of $2,270/man-week, the cost for inspection and testing would be (2 man-weeks/RY)($2,270/man-week) or $4,540/RY. For the 71 affected plants, the total cost was ($4,540/RY)(1,907 RY) or $8.7M. Because testing was already required every 10 years, this value was conservatively high.

NRC Cost: Three man-days/RY (0.6 man-week/RY) were estimated for the review of test and inspection requirements associated with the solution. At a cost of $2,270/man-week, the total cost for this review was (0.6 man-week/RY)($2,270/man-week)(1,907 RY) or $2.6M. Other costs, such as work with ASME Code Committees to increase valve testing frequencies, were estimated to be negligible.

Table 3.165-1
Change in Core-Melt Frequency for Various PWR Systems

PWR System	Valve Failure Probability Estimate		
	Best Estimate (5.0×10^{-3})	Lower Bound (1.0×10^{-3})	Upper Bound (5.0×10^{-2})
High Pressure Injection	1.0×10^{-5}	2.0×10^{-6}	1.0×10^{-4}
Diesel and Emergency Power	7.3×10^{-6}	1.5×10^{-6}	9.2×10^{-5}
Accumulator	5.0×10^{-6}	1.0×10^{-6}	4.8×10^{-5}
Reactor Coolant	2.3×10^{-6}	4.7×10^{-7}	2.1×10^{-5}
Residual Heat Removal/Low Pressure Injection	8.2×10^{-7}	1.6×10^{-7}	1.3×10^{-5}
Auxiliary Feedwater	6.7×10^{-7}	1.3×10^{-7}	9.2×10^{-6}
Chemical and Volume Control System	3.3×10^{-7}	6.7×10^{-8}	3.3×10^{-6}
PWR Total	2.6×10^{-5}	5.3×10^{-6}	2.9×10^{-4}

Table 3.165-2
Change in Core-Melt Frequency for Various BWR Systems

BWR System	Valve Failure Probability Estimates		
	Best Estimate (5.0×10^{-3})	Lower Bound (1.0×10^{-3})	Upper Bound (5.0×10^{-2})
Essential Service Water	1.6×10^{-6}	3.2×10^{-7}	1.4×10^{-5}
Diesel and Emergency Power	3.8×10^{-7}	7.5×10^{-8}	7.2×10^{-6}
RCIC	3.6×10^{-8}	7.2×10^{-9}	3.5×10^{-7}
HP Core Spray	1.7×10^{-8}	3.3×10^{-9}	1.7×10^{-7}
Main Steam	0	0	2.9×10^{-8}
BWR Total	2.0×10^{-6}	4.0×10^{-7}	2.2×10^{-5}

Table 3.165-3
PWR and BWR Results for Changes in Core-Melt Frequency and Public Risk

	Change in Core-Melt Frequency (per RY) for Various Valve Failure Probabilities			Change in Public Risk (man-rem/RY) for Various Valve Failure Probabilities		
	0.005	0.001	0.05	0.005	0.001	0.05
PWR	2.6E-05	5.3E-06	2.9E-04	73	15	770
BWR	2.0E-06	4.0E-07	2.2E-05	5.8	1.2	62

Total Cost: The total industry and NRC cost associated with the possible solution was $(8.7 + 2.6)M or $11.3M.

Impact/Value Assessment

Based on a potential public risk reduction of 10^5 man-rem and a cost of $11M, the impact/value ratio was given by:

$$R = \frac{\$11M}{10^5 \text{ man-rem}}$$

$$= \$110/\text{man-rem}$$

Other Considerations

The total ORE for implementation of the possible solution was estimated to be 380 man-rem for all affected plants.

CONCLUSION

Based on the impact/value ratio and the potential public risk reduction, this issue was given a HIGH priority ranking. In accordance with the RES evaluation,[1564] the impact of a license renewal period of 20 years will be considered in the resolution of the issue.

REFERENCES

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1456. NUREG/CR-5303, "System Analysis and Risk Assessment System (SARA) Version 4.0," U.S. Nuclear Regulatory Commission, (Vol. 1) February 1992, (Vol. 2) January 1992.

1520. Memorandum for E. Beckjord from T. Murley, "Request to Prioritize a New Generic Issue for Spring-Actuated Safety and Relief Valve Reliability," October 8, 1992.

1556. Memorandum for C. Rossi, et al., from T. Novak, "Safety and Safety/Relief Valve Reliability," April 24, 1992.

1557. NRC Information Notice No. 90-05, "Inter-System Discharge of Reactor Coolant," U.S. Nuclear Regulatory Commission, January 29, 1990.

1558. NRC Information Notice 92-64, "Nozzle Ring Settings on Low Pressure Water-Relief Valves," U.S. Nuclear Regulatory Commission, August 28, 1992.

1559. NRC Information Notice 92-61, "Loss of High Head Safety Injection," U.S. Nuclear Regulatory Commission, August 20, 1992, (Supplement 1) November 6, 1992.

1560. NUREG/CR-6001, "Aging Assessment of BWR Standby Liquid Control Systems," U.S. Nuclear Regulatory Commission, August 1992.

1561. NRC Information Notice No. 90-18, "Potential Problems With Crosby Safety Relief Valves Used on Diesel Generator Air Start Receiver Tanks," U.S. Nuclear Regulatory Commission, March 9, 1990.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 166: ADEQUACY OF FATIGUE LIFE OF METAL COMPONENTS

DESCRIPTION

Select portions of the STS contain requirements to monitor cumulative fatigue usage for critical components associated with the safety injection systems. In addition, STS Section 5.0, "Design Features," requires the tracking of certain transients to ensure that design bases are not exceeded. However, many plants do not have the STS or any requirement to monitor for fatigue limits. The resolution of Issue 78 was expected to determine the degree to which fatigue limit monitoring was necessary, address fatigue adequacy in general, and recommend actions, if any, to be taken by the staff. However, during the Commission meetings on promulgating requirements for license renewal, it became increasingly apparent that the adequacy of fatigue life of metal components should not be conducted solely for license renewal, but should also be conducted for existing operating plants. Therefore, NRR took[1517] the lead responsibility for addressing this issue for operating plants. The resolution of Issue 78 was to be integrated into the resolution of the Issue 166.

CONCLUSION

This issue was considered nearly-resolved based on the NRR decision to pursue resolution of the issue.[1517] In accordance with the RES evaluation,[1564] the impact of a license renewal period of 20 years will be considered in the resolution of the issue.

REFERENCE

1517. Memorandum for J. Sniezek from T. Murley and E. Beckjord, "Resolution of Fatigue and Environmental Qualification Issues Related to License Renewal," April 1, 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

ISSUE 167: HYDROGEN STORAGE FACILITY SEPARATION

DESCRIPTION

Historical Background

Issue 106 was resolved with the issuance of Generic Letter 93-06[1547] which included evaluation of the risk from: (1) the storage and distribution of H_2 for the volume control tank in PWRs and the main electric generator in BWRs and PWRs; (2) other sources of H_2 such as battery rooms, the waste gas system in PWRs, and the offgas system in BWRs; and (3) small, portable bottles of combustible gases used in maintenance, testing, and calibration. However, the potential risk from large H_2 storage facilities outside the reactor, auxiliary, and turbine buildings was not addressed. Studies performed during and subsequent to the resolution of Issue 106 raised concerns about the magnitude of the excluded risk.[1534,1535] Thus, in December 1993, this issue was identified[1532] to address this excluded risk.

NRC Information Notice No. 89-44[1552] was issued in May 1989 and each NRC Regional Office was expected to determine whether the plants in its region had similar safety-related concerns. The information compiled by these Offices was reviewed and issued in the preliminary report SCIE-EGG-103-89.[1535] The storage of gaseous or liquid H_2 at 119 power plants was then investigated and possible accident scenarios resulting from a fireball, explosion, or presence of unburned H_2 gas in ventilation air intakes were examined. Explosion was identified as the scenario posing the greatest risk potential. The analysis in SCIE-EGG-103-89[1535] focused on explosion with all quantification performed relative to this accident only.

Safety Significance

The safety concern was whether or not there is adequate physical separation between H_2 storage facilities and buildings or structures housing systems important to safety at nuclear power plants. As reported in SCIE-EGG-103-89,[1535] "[a]t the Trojan Nuclear Plant, April 17, 1989, [NRC] inspectors identified a potential safety problem concerning the storage of 32,000 standard cubic feet (scf) of hydrogen gas on the control room roof. The 32,000 scf was made up of four 8,000 scf tanks. This discovery raised concerns about possible similar hazards in the storage of hydrogen at other nuclear facilities."

Possible Solutions

Possible solutions included relocation (or placement in pits) of storage facilities, buildings, and equipment, and the construction of blast shields, or a combination of these. The resolution for this issue was assumed to be the construction of concrete walls enclosing the H_2 storage facility. This structure would serve as a blast shield in the event of an explosion, essentially eliminating the risk.

PRIORITY DETERMINATION

H_2 gas and cryogenic H_2 storage tanks are designed, fabricated, tested, and stamped in accordance with Section VIII, Division 1, of the ASME Code for unfired pressure vessels. The containers for gaseous H_2 are seamless, single-walled containers. Liquid H_2 is stored in vacuum-jacketed or double-walled vessels. The Handbook of Chemical Hazard Analysis (published jointly by FEMA, DOT, and EPA) lists accident rates and percentages of volume released for use in analyzing potential accidents involving H_2 storage containers. For single-walled containers, the accident rate suggested in this Handbook was 10^{-4}/tank-year. For these containers, the Handbook suggested that 90% of spills are terminated, while 10% are instantaneous total release of contents. Thus, for single-walled containers, the frequency of release of 100% of container contents was estimated to be 10^{-5}/tank-year. For double-walled containers, the accident rate suggested was 10^{-6}/tank-year. In this case, the entire container contents are released instantaneously 100% of the time. A frequency of 10^{-5}/tank-year for instantaneous release of 100% of vessel contents was assumed in this analysis.

The status of the 119 power plants was assessed[1535] with respect to H_2 tank farm separation guidelines in EPRI NP-5283-SR-A, "Guidelines for Permanent BWR Hydrogen Water Chemistry Installations." Sixteen percent were found not to meet the separation guidance with respect to explosion hazard. For the existing population of 110 plants, this translated into 18 LWRs not meeting the EPRI guidelines. (The permanently shut down Trojan PWR was excluded from this population. Thus, this analysis did not address H_2 storage tanks located on top of the control room roof.) However, in NUREG-1364,[1545] credit was assumed for an informal survey that showed mitigating factors to be insufficient at only three plants.

Frequency/Consequence Estimate

Of the types of accidents analyzed in risk assessments, H_2 tank farm explosions seem most similar to some accidents classified as external events. Furthermore, since such explosions could cause large pressure forces to be exerted upon building walls, or could cause possible impact by missiles, they would appear to be similar to tornadoes among the types of external events. However, unlike what is usually assumed for tornadoes, H_2 tank farm explosions probably would not exert a uniformly high and destructive pressure on all buildings on site at one time. Thus, the consequences from H_2 tank farm explosions were not expected to exceed those from tornadoes.

A review of available PRAs yielded the IPE for Oconee 3[1533] as most appropriate for this analysis. In this IPE, a fairly detailed assessment of tornado risk was performed, building on that from the earlier Oconee 3 PRA.[889] An added advantage to the selection of Oconee 3 was that it provided a description of the site's 48,000 scf H_2 tank farm which was deemed to be representative.[1535] This farm consisted of 6 tanks which, using the suggested values in the Handbook, resulted in an accident frequency of $(10^{-5}$/tank-year)(6 tanks/tank-farm)(1 tank-farm/reactor) = 6×10^{-5}/RY for an H_2 accident which releases 100% of the contents of at least one tank.

To put the amount of H_2 involved in perspective for the tank farm at Oconee, one tank contains 8,000 scf of H_2. This was equivalent to 216.8 lbs of TNT, using the EPRI Guidelines equivalence of 1,000 scf = 27.1 lbs of TNT for gaseous H_2

storage. Six tanks in the same farm contain an equivalent of 1300.8 lbs of TNT. In the terminology of the EPRI guidelines, both these amounts are considered to be in the "small equivalence" range (< 4000 lbs TNT). Terminology and equivalence notwithstanding, hypothesizing the detonation of one tank in a farm raises the question of subsequent damage to and detonation of adjacent tanks. The EPRI Guidelines were based on the safety analysis of the failure of single vessels and did not address simultaneous failure of multiple storage vessels. There was factual support for using a basis of only one tank failure. The Guidelines cited 3 events, 2 from reactor sites where H_2 container explosions did not damage adjacent cylinders. Given release of the contents of one cylinder, it was assumed in this analysis that: (1) detonation will occur; (2) possibly all of the tanks were involved; (3) since the tank-farm in question was assumed not to conform with EPRI Guidelines, appropriately selected plant damage would ensue with an appropriately assigned conditional probability.

For the purpose of analyzing tornado-generated missiles, Duke Power considered[1533] two categories of tornado events: (1) tornadoes whose winds impact on Oconee 3; and (2) tornadoes passing within 2,000 ft of Oconee 3. The latter category was subsequently dismissed when analysis showed the probability of a core-melt due to tornado-generated missiles to be 100 to 1,000 times lower than that due to tornado wind loadings; therefore, only the first category was addressed. Duke Power assumed[1533] that a tornado would render unavailable all offsite AC power sources except for one underground path. Tornadoes of intensity F-1 or less (i.e., with wind speeds < 113 mph) were assumed not to cause sufficient wind damage to generate a core-melt. Oconee had been designed to withstand wind loadings of F-1 tornadoes.

The EPRI Guidelines have been checked for responses for walls with static pressure capacities between 1.5 and 4.5 psi. Regulatory Guide 1.76[42] indicated that a 1.5 psi pressure drop could be expected for a design basis tornado with wind speed as low as 195 mph (the sum of rotational speed and minimum translational speed). This wind speed lies toward the upper end of the range for an F-3 tornado (158 - 206 mph). From Appendix B of the EPRI Guidelines, for a small yield such as that (216.8 lbs TNT) from one tank at the tank farm in question, the separation distance can be fairly small (about 60 ft) even for a plant with moderate wall ductility (μ = 3) and low-end (1.5 psi) static design pressure. This lends some justification to the assumption made that the appropriate minimum blast force to use in the analysis corresponds to that from an F-3 Tornado. Due to lack of knowledge of the exact number of tanks detonated (1 to 6) and other physical parameters involved, conditional probabilities of 1/3 were assigned to each of the resulting equivalent tornado forces F-3, F-4, and F-5. In other words, the 6×10^{-5}/RY initiating event frequency derived from the Handbook was considered to be uniformly distributed among the assumed equally likely outcomes F-3, F-4, and F-5. This was believed to be conservative, at least with respect to F-4 and F-5.

The turbine building was assumed[1533] susceptible to wall damage from F-2 and stronger tornadoes. Wall damage could fail the 4160V (4KV) AC switchgear that powers safety equipment and/or the Upper Surge Tank (UST), the prime suction source for the emergency feedwater pumps. The auxiliary building was assumed susceptible to wall damage from F-4 and stronger tornadoes (wind speeds > 206 mph), particularly the exterior walls of the West (WPR) and East Penetration Rooms (EPR). Damage to the WPR wall could fail piping and electrical penetrations including those from the Standby Shutdown Facility (SSF). This could lead to RCP

seal LOCAs, loss of the SSF backup for RCP seal cooling, and loss of feedwater from the SSF. Damage to the EPR wall would cause similar failures, although the likelihood of piping failures there was judged to be about ten times less due to tornado shielding by the reactor building. Other exterior components, such as the Borated Water Storage Tank, are also susceptible to failure from tornadoes. However, they did not appear in the listed cut sets for core damage and were not considered further.

Tornadoes falling within categories F-2 through F-5 resulted in accident sequences leading to various plant damage states (PDS). The total CDF (the sum of the accident sequence frequencies) was 9.74 x 10^{-6}/RY. However, after eliminating the PDS not resulting in offsite releases, the frequency was calculated to be 8.2 x 10^{-6}/RY.

There were 17 possible release categories associated with the PDS and each was assigned a conditional probability of release.[1533] When multiplied by the sequence frequency, each of these yielded the sequence frequency per release category. Associated with each category was a whole-body man-rem equivalent dose. The product of each release category frequency and its associated dose yielded a total risk of 9.11 man-rem/RY. These results for a tornado were then modified for an H_2 tank-farm explosion.

Again, unlike tornadoes, H_2 tank-farm explosions would not exert pressure on all site buildings at one time. Thus, multiple building wall failures were not expected as in the tornado accident sequences. To reflect this limitation, the cut sets of the tornado accident sequences were reviewed and it was found that nearly all contained conditional failure of the turbine building wall. Associated with this failure were failures of the UST and/or 4KV AC switchgear. Failures of the walls of the WPR and/or EPR were contained in less of the cut sets of the tornado accident sequences. Therefore, an H_2 tank-farm explosion was assumed to fail only the turbine building wall, resulting in failures of the UST and/or 4KV AC switchgear; no failure of the WPR or EPR walls was assumed. This eliminated most of the T(F4) and T(F5) sequences. Using the remaining sequences, the Handbook derived an initiating event frequency of 6 x 10^{-5}/RY, and the 1/3 conditional probability for each of the categories F-3, F-4, and F-5 resulted in a total CDF frequency from H_2 tank explosion of 4 x 10^{-6}/RY, which was less than that for tornadoes.

Using the same release category conditional probabilities and equivalent doses as for tornadoes, a total frequency over all release categories of 3 x 10^{-6}/RY (less than the total CDF since not all accident sequences lead to offsite release) and a total risk of 2.9 man-rem/RY were obtained. Thus, the risk was also less than that for tornadoes. Assuming 18 affected plants with an average remaining lifetime of 23 years, the total risk reduction potential was 1,201 man-rem.

Cost Estimate

Industry Cost: It was reported[1535] that the 48,000 scf Oconee tank-farm consisted of 6 tanks that covered an area 45 ft by 30 ft. It was surrounded by an exclusion fence and was always lighted. The proposed concrete enclosure was assumed to have the same dimensions as the 6 Oconee tanks combined. From the 1993 Means Building Construction Cost Data (51st Annual Edition), the costs were obtained for thick, smooth, gray, architectural pre-cast concrete slabs 10 feet high and 6 inches

thick. For a 20-ft length, the cost was $\$14.95/ft^2$ (area) and, for a 30-ft length, the cost was $\$14.60/ft^2$. To form an enclosure at least 45 ft by 30 ft, two 20-ft sections and four 30-ft sections would be needed. A height of 10 feet was considered sufficient to protect the surroundings from horizontal blast effects; however, a thickness comparable to that of site building walls (~18 in) was necessary. Thus, the total number of precast concrete wall panels was:

30-ft panels:	(4/perimeter)(3 at 6-in thickness each)	= 12
20-ft panels:	(2/perimeter)(3 at 6-in thickness each)	= 6
	Total	= 18

The enclosure would be 50 ft by 30 ft, yielding a total wall panel area of (2)(50 + 30)ft(10 ft)(3 panels) or 4,800 ft^2. At $\$15/ft^2$, the cost of this enclosure would be $(\$15/ft^2)(4{,}800\ ft^2)$ or \$72,000.

In the Means manual cited above, it was stated that, "[i]f the work is to be subcontracted, add the general contractor's markup, approximately 10%." In addition, the enclosure will have to be anchored in place and penetrated for piping and access. Combined with the general contractor's markup, these factors were assumed to increase the cost of the enclosure by about 50%, bringing the total cost to (1.5)(\$72,000)/plant or \$108,000/plant.

Any industry operation and maintenance activities associated with this resolution were assumed to be performed as part of activities already in place, such as standard inspection and reporting procedures. No industry cost was anticipated for operation and maintenance. Thus, the total cost for 18 plants was \$1.94M.

NRC Cost: The resolution was assumed to require \$100,000 for development of a "typical uncomplicated TS change" and an implementation cost of \$11,000/plant (1988 dollars) with a 4% inflation rate. For 18 affected plants, the total cost was estimated to be \$341,000.

Total Cost: The total NRC and industry cost associated with the possible solution was estimated to be \$(1.94 + 0.341)M or \$2.28M.

Impact/Value Assessment

Based on a potential public risk reduction of 1,201 man-rem and an estimated cost of \$2.28M, the impact/value ratio was given by:

$$R = \frac{\$2.28M}{1{,}201\ \text{man-rem}}$$

$$= \$1{,}898/\text{man-rem}$$

Other Considerations

(1) The number of affected plants was determined by identifying those that did not conform to the EPRI separation criteria that were based on an H_2 to TNT detonation equivalency. Had more stringent criteria been used, the number of affected plants might have been larger. It was concluded in EGG-SSRE-8747[1534] that "the hydrogen to TNT detonation equivalency used in previous calculations should no longer be used." The stated reason for this was

that "the separation distances results from previous calculations [including those of the EPRI criteria] can be either overconservative or unconservative depending upon the set of hydrogen detonation parameters that are used." Nevertheless, this analysis was considered to be sufficiently conservative, particularly with respect to the assumption that all tanks are single-walled and assignment of conditional probabilities of 1/3 for F-4 and F-5 resultant forces.

An informal survey of all plants cited in NUREG-1364[1545] showed that, of those plants that did not meet the EPRI criteria for separation distances for safety-related air intakes or structures, mitigation features were insufficient at only 3 of the plants. Use of 3 affected plants instead of 18 would also result in a low impact/value score.

(2) Assuming a license renewal period of 20 years with the 18 affected plants operational 75% of this time, the additional risk reduction would be (18)(2.9 man-rem/RY)(20)(0.75) or 783 man-rem. Since there would be no increase in cost, the impact/value ratio would be $1,149/man-rem.

CONCLUSION

Based on the impact/value ratio and the potential reduction in CDF and public risk, this issue was given a LOW priority ranking. Consideration of a license renewal period of 20 years would not change this ranking.

REFERENCES

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889. NSAC-60, "A Probabilistic Risk Assessment of Oconee Unit 3," Electric Power Research Institute, June 1984.

961. NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986.

1532. Memorandum for C. Serpan from W. Minners, "Identification of New Generic Issue: Hydrogen Storage Facility Separation." December 16, 1993.

1533. Letter to the NRC from M. Tuckman (Duke Power Co.), "Oconee Nuclear Station Unit 3 Probabilistic Risk Assessment," November 30, 1990.

1534. EGG-SSRE-8747, "Technical Report: Improved Estimates of Separation Distances to Prevent Unacceptable Damage to Nuclear Power Plant Structures from Hydrogen Detonation for Gaseous Hydrogen Storage," EG&G Idaho, Inc., Idaho Falls, Idaho, November, 1993.

1535. SCIE-EGG-103-89, "Draft Technical Evaluation Report on U.S. Commercial Power Reactor Hydrogen Tank Farms and Their Compliance with Separation Distance Safety Criteria," Scientech, Inc., Idaho Falls, Idaho, March, 1990.

1545. NUREG-1364, "Regulatory Analysis for the Resolution of Generic Safety Issue 106: Piping and the Use of Highly Combustible Gases in Vital Areas," U.S. Nuclear Regulatory Commission, June 1993.

1547. Letter to All Holders of Operating Licenses or Construction Permits for Nuclear Power Reactors, "Research Results on Generic Safety Issue 106, 'Piping and the Use of Highly Combustible Gases in Vital Areas' (Generic Letter 93-06)," U.S. Nuclear Regulatory Commission, October 25, 1993.

1552. NRC Information Notice No. 89-44, "Hydrogen Storage on the Roof of the Control Room," U.S. Nuclear Regulatory Commission, April 27, 1989.

ISSUE 168: ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

DESCRIPTION

As discussed in SECY-93-049,[380] the staff reviewed significant license renewal issues and found that several related to environmental qualification (EQ). A key aspect of these issues was whether the licensing bases, particularly for older plants whose licensing bases differ from newer plants, should be reassessed or enhanced in connection with license renewal or whether they should be reassessed for the current license term. The staff concluded that differences in EQ requirements constituted a potential generic issue which should be evaluated for backfit independent of license renewal.[1518]

During the staff's development of an interoffice action plan to address upgrading EQ requirements for older plants during the current licensing term, the staff evaluated the technical adequacy of EQ requirements. As part of this evaluation, the staff reviewed tests of qualified cables performed by SNL, under contract with the NRC. The purpose of these tests was to determine the effects of aging on cable products used in nuclear power plants. After accelerated aging, some of the environmentally-qualified cables either failed or exhibited marginal insulation resistance during accident testing, indicating that qualification of some electric cables may have been non-conservative. Although the SNL tests may have been more severe than required by NRC regulations, the test results raised questions with respect to the EQ and accident performance capability of certain artificially-aged cables. Depending on the application, failure of these cables during or following design basis events could affect the performance of safety functions in nuclear power plants.

CONCLUSION

This issue was considered nearly-resolved based on the NRR decision to pursue resolution of the issue.[1517] In accordance with the RES evaluation,[1564] the impact of a license renewal period of 20 years will be considered in the resolution of the issue.

REFERENCES

380. SECY-93-049, "Implementation of 10 CFR Part 54, 'Requirements for Renewal of Operating Licenses for Nuclear Power Plants,'" March 1, 1993.

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1518. Memorandum for The Chairman et al., from J. Taylor, "Environmental Qualification of Electric Equipment," May 27, 1993.

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ISSUE 170: FUEL DAMAGE CRITERIA FOR HIGH BURNUP FUEL

DESCRIPTION

Historical Background

Following the TMI-2 accident, the NRC converted its fuel behavior research program into a severe accident research program and, consequently, no further confirmatory work on fuel damage criteria was pursued. However, some work of this type was conducted by foreign agencies and, in March 1994, the NRC received the results from a reactivity test in the French Cabri test reactor which showed multiple brittle failures at a relatively low energy of 30 calories/gram (cal/gm) in the cladding of a commercial fuel rod with a burnup of 63 gigawatt-days/ton (GWd/t); dispersal of finely divided fuel particles was also observed. Test results from the Japanese Nuclear Safety Research Reactor (NSRR) and the Russian Impulse Graphite Reactor (IGR) also appeared to indicate reduced failure thresholds and fuel dispersal. The corresponding failure threshold used by the NRC for some similar situations is 170 cal/gm and no loss of fuel is assumed below 280 cal/gm.

Licensee requests for higher burnup fuel limits in operating reactors resulted in the issuance of an NRR request[1595] for an RES assessment of fuel damage thresholds for reactivity transients. Confirmatory analysis of fuel conditions required RES to request experimental data from the French test.[1596] Information Notice 94-64[1597] was issued and the Commission was informed[1598] of the staff's actions. Following staff review of the Cabri test data, an assessment[1599] of its safety significance was forwarded to the Commission. High burnup fuel behavior was the subject of Session 11 of the Twenty-Second Water Reactor Safety Information Meeting, the transactions of which were documented in NUREG/CP-0139.[1600]

Safety Significance

Changes in fuel pellets and cladding occur at high burnups that appear to reduce fuel resistance to damage. Two of these changes are: (1) a reduction in cladding ductility that results from neutron damage and internal hydriding associated with oxidation; and (2) the formation of a very fine grain structure in the fuel pellets and the accumulation of microscopic fission gas bubbles on the grain boundaries. While the underlying processes that cause these changes have been known for many years, the extent and effects of these changes were not realized until recently.

Fuel damage criteria for LOCAs are also brought into question at very high burnups. To avoid fragmentation during quenching, 10 CFR 50.46 requires that the peak cladding temperature not exceed 2200°F and that the total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation. Reduced ductility at high burnup due to internal hydriding may affect the validity of these limits. Further, oxidation during normal operation to burnups above 50 GWd/t has been observed to be on the order of 15% of the cladding thickness, leaving little margin for additional oxidation during an accident.

GDC 10 requires that specified acceptable fuel design limits are not to be exceeded during normal operation, including anticipated operational occurrences. Such limits are specified by applicants and approved by NRC, rather than being prescribed. The limits are intended to keep the fuel rod cladding from leaking, thus protecting its function as a fission product barrier; a commonly used value is a 1% limit on cladding strain. Ductility of cladding from fuel with burnups around 60 GWd/t is found to be reduced by a factor on the order of 5, compared with unirradiated cladding, with observed uniform strains of 1% or less at the time of rupture. It is thus unlikely that a 1% strain limit is providing the protection desired for high burnup fuel. As discussed below, the safety significance of these fuel damage criteria varies depending on the type of event

Reactivity Transients: These transients can lead to pressure pulses in the coolant, loss of coolable fuel geometry, and releases of radionuclides. The absence of pressure pulses, implied by the present criteria, is probably not affected by high burnups; while fine particulates may be formed, high temperatures (above 300 cal/gm) required to generate pulses should not occur in high burnup fuel by an even wider margin. Fuel dispersal constitutes loss of coolable geometry and may occur with low energy depositions at high burnup; however, the worst reactivity transients are very localized, and localized loss of geometry should not lead to a core-melt. The lower threshold for release of gap activity plus the dispersal of particulate fuel at high burnup would increase plant activity and public dose, and the dispersal of fuel would alter the character of these Chapter 15 transients.

LOCAs: Excessive oxidation of cladding (i.e., more than 17%) on high burnup fuel could, in principle, lead to loss of coolable geometry from hydraulic loads (from the ECCS) without ever experiencing high temperatures during a blowdown. On the other hand, additional oxidation may not occur during the transient regardless of the amount of initial oxidation present on high burnup fuel. Transient temperatures for these accidents are very sensitive to power level, and even marginally lower power levels in high burnup fuel might keep transient temperatures sufficiently low to avoid further oxidation. If either the criteria or the safety analyses fail to provide a margin to loss of coolable geometry, then a core-melt could result from these design basis accidents.

Specified Acceptable Fuel Design Limits: Failure of the 1% strain limit or any other "specified acceptable fuel design limit" to provide the assurance that is assumed would result in plant releases or public doses that are not permitted during normal operation. None of these situations, however, should lead to core damage.

Possible Solution

Resolution of this issue could be accomplished by updating the existing burnup-independent criteria to include the effects of burnup, or to develop substitute criteria, as appropriate. Updated criteria could be incorporated in revisions to 10 CFR 50.46, Regulatory Guide 1.77,[1594] and SRP[11] Section 4.2, as necessary. Implementation of the resolution would require a screening of certain approved licensing topical reports and reloads that were reviewed previously to permit reactor operation to high burnups.

PRIORITY DETERMINATION

Existing and emerging data, largely from foreign sources, are expected to be adequate for the criteria revisions envisioned. At the time the issue was evaluated in May 1995, NRC programs to obtain and analyze these data were being planned or were in place; no major new testing programs were anticipated. The provisions in 10 CFR 50.46 that are in question were controversial when originally established and changes to this regulation will be avoided unless absolutely necessary; it is possible that the existing criteria can continue to be used as long as careful attention is given to initial oxidation and method of analysis for high burnup fuel.

Significant changes in exposure of plant operating staff are not expected during normal operation. Although the specified acceptable fuel design limits are probably not providing the protection intended, it is believed that licensees are employing more stringent measures that are not derived from the licensing safety analysis, e.g., power maneuvering restrictions and barrier fuel designs are being used to reduce fuel failures, which the 1% strain limit would not prevent. On the other hand, reductions would be expected in exposure of plant operating staff following a major transient or accident. These reductions could be accomplished by changes in operating conditions or fuel designs such that fewer fuel failures would occur during accidents and attendant fuel dispersal would be avoided.

CONCLUSION

At the time this issue was identified, an action plan for resolving the issue had been developed by the staff and presented to the Commission. Thus, resolution was planned and in progress and the issue was considered nearly-resolved. The impact of a license renewal period of 20 years will be considered in the resolution of the issue.

REFERENCES

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1594. Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors," U.S. Nuclear Regulatory Commission, May 1974.

1595. Memorandum for E. Beckjord from T. Murley, "User Need for Assistance on High Burnup Fuels," October 4, 1993.

1596. Memorandum for W. Russell from E. Beckjord, "Fuel Damage Criteria for Reactivity Transients," April 29, 1994.

1597. NRC Information Notice 94-64, "Reactivity Insertion Transient and Accident Limits for High Burnup Fuel," U.S. Nuclear Regulatory Commission, August 31, 1994, (Supplement 1) April 6, 1995.

1598. Memorandum to The Chairman, et al., from J. Taylor, "Reactivity Transients and High-Burnup Fuel," September 13, 1994.

1599. Memorandum to The Chairman, et al., from J. Taylor, "Reactivity Transients and Fuel Damage Criteria for High Burnup Fuel," November 9, 1994.

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ISSUE 171: ESF FAILURE FROM LOOP SUBSEQUENT TO A LOCA

DESCRIPTION

Historical Background

This issue was identified[1585] by NRR following the issuance of NRC Information Notice (IN) 93-17[1586] which was based in part on a deficiency in the Surry Power Station emergency diesel generator (DG) loading. This deficiency could have resulted in overloading the DGs if a LOCA occurred and was followed by a LOOP prior to reset of the safety injection signal. The staff subsequently learned from the NSSS Owners' Groups that other plants also were not necessarily designed to respond properly to a LOCA followed by a delayed LOOP if reset of the SIS had not occurred. The NRC did not request any specific action by (or information from) licensees in IN 93-17.[1586]

Nevertheless, on April 29, 1993, the Nuclear Utility Backfitting and Reform Group (NUBARG) objected to IN 93-17[1586] on the grounds that it "reflects new staff positions and presents the potential for plant-specific backfits." NUBARG requested that CRGR review IN 93-17[1586] because "the generic position stated in IN 93-17[1586] could be used to seek additional licensee analysis and costly plant modifications." NUBARG based its contention that IN 93-17[1586] was a backfit solely on the resolution of Issue 17, "Loss of Offsite Power Subsequent to a LOCA." The resolution of Issue 17 was based on the assumption that a LOOP would be an independent event following a LOCA and would not be precipitated by a LOCA.

Pursuant to NUBARG's request, CRGR reviewed IN 93-17.[1586] In its response to NUBARG, CRGR first noted that the concern identified in Issue 17 was not the same scenario as that described in IN 93-17,[1586] but did agree with NUBARG that the wording of the IN "implies the existence of an approved generic position," despite the fact, conceded by NUBARG, that the IN did not "include a request for specific action by licensees." The only change to the IN required by CRGR was to "clarify NRC intent with regard to any backfit concerns raised by the initial wording and to place emphasis on the potential safety concern being addressed." The letter finally noted that "the staff is considering the need for further generic action to determine if all power reactor licensees should be required to demonstrate the capability to withstand the LOCA/delayed LOOP sequence of concern" and that any "new proposed NRC generic position or requirement in this area would, of course, be subject to review under the backfit rule in accordance with existing NRC backfit procedures."

Safety Significance

When a LOCA occurs at a PWR, the ESFAS will be actuated by one of four automatic signals, or by manual operator action if the plant operators detect the LOCA before the automatic signals respond. These four automatic signals are:

(1) Low Pressurizer Pressure
(2) High Containment Pressure
(3) High Steam Line Flow Rate Coincident with either Low Steam Line Pressure or Low-Low T_{avg}

(4) Steam Line High Differential Pressure.

The ESFAS will cause the following system responses:

(A) Reactor trip initiated
(B) Safety Injection Sequence initiated (ECCS pumps started and aligned for core cooling)
(C) Phase "A" containment isolation
(D) Auxiliary feedwater initiated
(E) Main feedwater isolated
(F) Emergency DG Startup
(G) Auxiliary Cooling System Line-up (pumps started in essential service water and Component Cooling Water systems)
(H) Control Room and Containment Ventilation Isolation.

The DGs might be unable to handle the simultaneous starting of all of the pumps and motors actuated by the ESFAS and for most plants it is necessary to sequence the startup of all ESFAS-actuated systems to prevent overloading of the DGs. There are similar system responses for LOCAs at BWRs.

This issue concerns the ability of the ESFAS sequencing to respond to a LOOP which might occur during the sequencing. Issue 17 addressed only one aspect of this issue: the probability of a randomly occurring LOOP after a LOCA. Issue 171 was primarily concerned with a LOOP caused by the LOCA event and ESFAS sequencing. Thus, the LOCA and subsequent LOOP would not be independent events. The loss of a large amount of electric power generation, as might be precipitated by the trip of the unit with the LOCA, can cause transmission system grid instability resulting in a total LOOP. The loss of generation from the LOCA unit can also result in degraded voltage at the unit switchyard, resulting in actuation of degraded voltage protection and subsequent total LOOP. Plants that have no TS upper setpoint limit on degraded voltage sensing and have little margin between the setpoint and minimum operating grid voltage may be susceptible to this problem.

Besides transmission system grid problems, a LOOP may also occur because of plant electrical distribution system problems. In many plants, the main generator normally feeds the plant loads through a unit auxiliary transformer. When the reactor trips, the main generator often remains connected to the plant electrical systems and high voltage switchyard until protective relaying transfers the power source from the main generator to an offsite power source. If the transfer fails during the ESFAS sequencing, the buses which provide power to ESF systems would become isolated from offsite power sources and the DGs would be required to provide power in that event.

It is possible that the DGs could be damaged with no immediate possibility of recovery during this scenario if they attempt to re-energize the entire portion of the previously sequenced load without resequencing. Two utility reports identify another failure mechanism in which circuit breaker protective devices lock out the circuit breaker to protect it from potential damage resulting from repeated opening and closing (referred to as "pumping"). The operator actions required to reset the circuit breakers may be quite complicated and could result in a high probability of failure to recover. A third failure mechanism involves the lockup of timers in the accident load sequencing logic which could result in the loss of all automatic accident loading capability.

In addition to the electrical power system and control system concerns, the coolant systems may also be vulnerable to damage resulting from plant transients during ESF sequencing. Drain-back in coolant systems during power supply transients and switchovers, even assuming that the power is eventually restored, can result in the formation of voids in outlet piping that can lead to water hammer. Water hammer can damage pipes and pipe supports. Restarting a pump which has open outlet valves can require significantly more power than the pump motor was designed to draw during startup, which can exacerbate the electrical power system problems.

These concerns can be modeled for prioritization purposes as a failure of ECCS in the event of LOCA with no possibility of recovery. Other accident sequences are not effected, because the failure scenario in this issue only occurs when a LOOP occurs during or shortly following ESFAS sequencing.

Possible Solutions

Any solution should address the potential for failure of ESF systems resulting from a LOOP subsequent to the initiation of ESF sequencing. The potential for a loss of power or other interruption of the ESF during sequencing may have been considered in the initial design of the ESF systems, despite the absence of prescriptive NRC requirements or a documented staff position requiring such analysis. If this analysis had been done, it is possible that many licensees will not need to make modifications to their existing designs. The following elements are presented as possible solutions for plants that may require some action.

(1) Analyze and reset protective relaying and control circuitry to respond properly to a LOOP during ESF sequencing.

(2) Analyze coolant systems to verify that a loss and restoration of power will not result in water hammer, cavitation, or other potentially damaging conditions.

(3) Analyze power transmission system and plant electrical distribution system capability under ESF sequencing conditions to demonstrate sufficient system capability.

PRIORITY DETERMINATION

Assumptions

The worst case response to a LOOP during ESF sequencing initiated by a LOCA would be non-recoverable damage to the DGs and ECCS pump motors. This damage could occur if the DGs were switched to ESF buses without phase-synchronizing relays or other protective devices to prevent out-of-phase connection. The transient currents created by out-of-phase connection between a motor and a generator would be limited only by conductor resistances and machine sub-transient reactances, and could be of sufficient magnitude to severely damage the motor or generator windings and phase leads. Such damage would require several days to repair at a minimum. For the purposes of this analysis, it was assumed under the above stated scenario that all ECCS will fail without possible recovery in the event of a LOOP after a LOCA. There are other scenarios, such as DG overloading, that could potentially damage the DGs with no immediate possibility of recovery, but the out-of-phase connection was used as a representative worst case.

The probability of ECCS failure following an out-of-phase connection would not be 100%, because some degree of phase angle difference between the DGs and the ECCS motors could probably be tolerated without causing damage to the motor or generator windings, or actuation of overcurrent protection. An exact determination of the tolerance for out-of-phase switching would require a system- and component-specific analysis, but it was conservatively assumed that damage will occur if the DGs and the load are greater than 90 electrical degrees out of phase. This situation will occur on a random basis 50% of the time.

The probability of a LOOP subsequent to a LOCA was previously addressed in Issue 17 where the only source of LOOP considered was a random occurrence. The events which resulted in the identification of Issue 171 involved the loss of offsite power to the ESF buses that would be dependent on the initiating event, ESF actuation, which causes a reactor trip and sequential loading of the ESF buses. In addition, there was also a concern that the transmission system might lose stability or not be able to maintain sufficient voltage following the loss of generation from a nuclear power plant at a probability greater than 10^{-3}, which was the probability used in WASH-1400[16] and Issue 17. For comparison, the probability used in NUREG-1150[1081] and NUREG/CR-4550[1318] was 2×10^{-4}.

In AEOD/E93-02, a review of LOOP events indicated that 37% of all plant-centered LOOP events (15 out of 41 events) that occurred during power operation resulted in a total LOOP. This statistic indicates that offsite power source independence is relatively poor in that, if a single offsite power source is lost, there is significant probability that all offsite power sources will be lost. The results of the AEOD study are used in the analysis of this issue as the upper limit for the probability of a loss of offsite power in the event of a LOCA.

The size of nuclear power plants has increased significantly since the mid-1970s when WASH-1400[16] was published and power companies have relied increasingly on dispersed non-utility generation. These changes in the transmission system as well as additional load growth may have resulted in a greater probability of transmission system instability in general, and degradation or loss of offsite power at a large nuclear power plant subsequent to rapid load shedding in particular. In order to accurately determine the probability of a LOOP subsequent to a LOCA, it would be necessary to perform plant-specific analyses of their transmission systems and plant distribution systems. For the purposes of this analysis, a range of probabilities from 30% to 0.1% was considered.

Frequency Estimate

The increase in CDF resulting from the non-recoverable failure of ECCS after a LOOP during ESF sequencing was estimated for three plants: Surry, Grand Gulf, and Zion. These three plants were initially analyzed under the assumption that a LOOP subsequent to a LOCA would not cause non-recoverable ECCS failure. The failure of the ECCS was modeled as the product of the probability of LOOP (ranging from 0.3 to 0.001), the probability of out-of-phase synchronization in the absence of phase-sequencing relays (0.5), and the LOCA-initiating event frequency. Therefore, the base case CDF was the initiating event frequency for the LOCA events times the probability of a LOOP and DG/ECCS failure, minus any recovery actions which do not require ECCS or DGs.

For example, Surry has four LOCA events: large LOCA, medium LOCA, small LOCA, and very small LOCA. These events are described below. A similar analysis was used for Grand Gulf and Zion.

(1) Large LOCA - the large LOCA sequence requires the following systems for mitigation: accumulators, low pressure injection, containment cooling systems, and low pressure recirculation. Core damage is avoided in the base case only if all systems operate successfully, although if containment cooling fails, one sequence results in containment failure but no core damage. The initiating event frequency for a large LOCA is 5×10^{-4}/RY.

(2) Medium LOCA - the medium LOCA sequence is similar to the large LOCA sequence, except that high pressure injection is also required for success. The initiating event frequency for a medium LOCA is 10^{-3}/RY.

(3) Small LOCA - the small LOCA sequence is similar to the medium LOCA sequence, except that the reactor protection system, the auxiliary feedwater system, the pressure release valves, operator depressurization, and high pressure recirculation may be used for recovery. All recovery actions require low pressure recirculation and high pressure recirculation, so ECCS/DG failure is non-recoverable. The initiating event frequency for a small LOCA is 10^{-3} /RY.

(4) Very small LOCA - the very small LOCA sequence is similar to the small LOCA sequence, except that the main feedwater system and the residual heat removal system may be used for recovery. All recovery actions require low pressure recirculation and high pressure recirculation, so ECCS/DG failure is non-recoverable. The initiating event frequency for a very small LOCA is 1.3×10^{-2} /RY.

The sum of the above four LOCA-initiating event frequencies is 1.6×10^{-2}/RY. The base case ΔCDF was defined as follows: $\Delta CDF = (P_{loop})(P_{sync})(P_{init})$

where P_{loop} = probability of LOOP following LOCA
P_{sync} = probability of out-of-phase synchronization
P_{init} = initiating event frequency

The ΔCDF for Surry, Grand Gulf, and Zion were summarized as follows:

Dependent LOOP Probability	Surry ΔCDF (/RY)	Grand Gulf ΔCDF (/RY)	Zion ΔCDF (/RY)
0.300	2.4×10^{-3}	5.0×10^{-3}	5.5×10^{-3}
0.100	8.0×10^{-4}	1.7×10^{-3}	1.8×10^{-3}
0.030	2.4×10^{-4}	5.0×10^{-4}	5.5×10^{-4}
0.010	8.0×10^{-5}	1.7×10^{-4}	1.8×10^{-4}
0.003	2.4×10^{-5}	5.0×10^{-5}	5.5×10^{-5}
0.001	8.0×10^{-6}	1.7×10^{-5}	1.8×10^{-5}

The event was not originally modeled in any of the three PRA models under consideration. The calculated ΔCDF for this accident scenario is therefore the total increase in CDF over the existing total CDF for each plant.

Resolution of this issue would result in no additional contribution to previously calculated CDFs from this accident sequence. Based on the estimated number of plants (73 PWRs, 35 BWRs) and remaining life (PWRs - 23 years, BWRs - 21 years), there were approximately 2,414 RY of operation affected by this issue (PWRs - 1679, BWRs - 735). Using the average of ΔCDFs calculated for Surry and Zion for PWRs and the ΔCDFs calculated for Grand Gulf for BWRs yielded the following estimated total reduction in CDF from resolution of this issue over the remaining life of these plants. It was assumed that all operating plants were in the worst-case condition. The actual number of plants in the worst-case condition is unknown, but is probably no more than 10% to 20%.

Dependent LOOP Probability	PWR Events	BWR Events
0.300	6.6	3.7
0.100	2.2	1.3
0.030	0.7	0.4
0.010	0.2	0.1
0.003	0.07	0.04
0.001	0.02	0.01

Consequence Estimate

A radiation dose of 4.5×10^6 man-rem/event was given in Gore et al (1988) for PWRs and BWRs. This figure was used for simplicity because the accident sequences for large, medium, small, and very small LOCAs result in different energy levels of release.

Cost Estimate

Industry Cost: Implementing the possible solutions listed above would have variable costs. For plants already designed to recover from a LOOP during ESF sequencing, the only costs would be those associated with verification and responding to the NRC (Category A). For plants not designed to be capable of recovering from a LOOP during ESF sequencing, the amount of work required would depend on the magnitude of the design deficiency. If the ESF control logic were the only hardware/software requiring modifications, costs would be relatively modest (Category B). If the coolant system were not properly designed to allow timely recovery in the event that ESF sequencing is interrupted, then it is possible that check valves or other similar equipment may be required (Category C). These changes might require substantial capital. It should be noted that the plants that would incur the greatest costs would be those that are at the greatest risk of core damage from a LOOP during ESF sequencing.

The following ranges were estimated as the implementation costs that might be incurred for the possible solution:

Category A	$1M or less
Category B	$2M to $8M
Category C	$5M to $20M

NRC Cost: Development of the possible solution was estimated to be $200,000 based on 24 man-months of labor to further evaluate the issue, develop a resolution, and perform a regulatory analysis. NRC support for implementation of the solution was estimated to require 1 man-week/plant for an additional cost of $210,000.

Review of operation and maintenance associated with the solution was estimated to take 1 man-day/RY for an additional cost of $1M. Therefore, the total NRC cost was estimated to be $1.4M.

Impact/Value Assessment

Because of the uncertainty of the number of plants in each of the three categories and the probability that the plants posing the greatest risk would be those requiring the most work to correct design deficiencies, a plant-specific impact/value assessment was calculated.

The maximum probability of a LOOP during ESF sequencing for plants in Categories A, B, and C was assumed to be 0.003, 0.1, and 0.3, respectively. Plants in Category A were those with properly designed coolant systems and ESF sequencing logic, but these plants may still be at a greater risk from a LOOP because of transmission system instability or other plant-specific features than were assumed in the analysis for Issue 17. Plants in Category B have inadequate ESF control logic which contributes to the probability of equipment damage, but nevertheless have adequately designed coolant systems that will be able to function as designed if offsite power is restored. Plants in Category C have both inadequate ESF control logic and coolant system design and are at risk of damaging equipment and not being able to recover.

The following table provides the impact/value scores for the ranges of values and impacts described above. The estimated NRC costs were less than the expected accuracy of the industry cost estimates. The estimated CDF was the average of the three plants considered in this evaluation (Surry, Grand Gulf, and Zion). Risk estimates were the product of the ΔCDF, the average remaining life of 22.3 years, and the consequence estimate of 4.5×10^{6} man-rem.

Category	ΔCDF(/RY)	ΔRisk (man-rem)	Cost ($M)	Impact/Value ($/man-rem)
A	4.3×10^{-5}	4,300	1	231
B	1.4×10^{-3}	140,000	2 to 8	14 to 57
C	4.3×10^{-3}	430,000	5 to 20	12 to 47

Other Considerations

Occupational Dose Increase: Occupational dose increase would result from implementation and operation and maintenance of the solution.

Dose increase due to implementation would depend on the plant category. For plants in Categories A and B, it was estimated that utility labor in radiation zones would be required for resetting or re-wiring of existing equipment. A total of 1 man-week/plant was estimated and a 75% utilization factor was assumed for labor in radiation zones. It was further assumed that the radiation dose rate in the radiation zones was 100 millirem/hour. Assuming that 108 plants are affected, this yielded a total of 320 man-rem.

For plants in Category C, a total of 30 man-weeks/plant was estimated and a 75% utilization factor was assumed for labor in radiation zones. It was further assumed that the dose rate in the radiation zones was 100 millirem/hour. Assuming that 108 plants are affected, this yielded a total of 9,700 man-rem.

No increase in dose due to operation and maintenance would be required for Categories A and B plants. For Category C plants, it was assumed that one additional man-week of utility labor in radiation zones would be required for examination of equipment installed or exchanged as a result of the solution. Assuming a 75% utilization factor, the incremental labor in radiation zones for operation and maintenance was estimated to be 30 man-hours/RY. Using the estimated 2,414 RY of operation remaining, the total increase was estimated to be 7,200 man-rem. For 108 plants, this yielded a total occupational dose increase ranging from 320 to 17,000 man-rem.

Occupational Dose Reduction Due To Accident Avoidance: The occupational dose reduction due to accident avoidance was calculated from the reduction in CDF multiplied by the assumed accident dose of 19,900 man-rem.[64] Using 108 plants and 2,414 RY of operation remaining, the total estimated dose reduction due to accident avoidance was calculated to range from 2,200 to 210,000 man-rem.

Cost Savings Due To Accident Avoidance: The total accident avoidance cost savings were estimated to be the reduction in CDF (from 4.3×10^{-5} event/RY for Category A to 4.3×10^{-3} event/RY for Category C) multiplied by the estimated cost of a core-melt accident ($1.65 Billion) and the estimated remaining operating years (2,414). This resulted in a total cost savings range of $170M to $17 Billion.

CONCLUSION

Based on the risk reduction potential and the impact/value ratio, this issue was given a HIGH priority ranking. The impact of a license renewal period of 20 years will be considered in the resolution of the issue.

REFERENCES

16. WASH-1400 (NUREG-75/014), "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," U.S. Nuclear Regulatory Commission, October 1975.

64. NUREG/CR-2800, "Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development," U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

1081. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Vol. 1) December 1990, (Vol. 2) December 1990, (Vol. 3) January 1991.

1318. NUREG/CR-4550, "Analysis of Core Damage Frequency from Internal Events," U.S. Nuclear Regulatory Commission, (Vol. 1, Rev. 1) January 1990, (Vol. 2) April 1989, (Vol. 3, Rev. 1) April 1990, (Vol. 4, Rev. 1) August 1989, (Vol. 5, Rev. 1) April 1990, (Vol. 6) April 1987, (Vol. 7, Rev. 1) May 1990.

1585. Memorandum for L. Shao from B. Sheron, "Proposed Generic Issue on Safety Systems' Response to the Sequential Occurrence of LOCA and Loss of Offsite Power Events," February 17, 1995.

1586. NRC Information Notice 93-17, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," March 8, 1993, (Rev. 1) March 25, 1994.

TASK HF4: PROCEDURES

This task was developed to provide assurance that plant procedures were adequate and could be used effectively. The objective was to provide procedures that would guide operators in maintaining plants in a safe state under all operating conditions, including the ability to control upset conditions without first having to diagnose the specific initiating event. This objective was to be met by: (1) developing guidelines for preparing, and criteria for evaluating, EOPs, normal operating procedures, and other procedures that affect plant safety; and (2) upgrading the procedures, training the operators in their use, and implementing the upgraded procedures. This task was divided into five distinct items as discussed below.

ITEM HF4.1: INSPECTION PROCEDURE FOR UPGRADED EMERGENCY OPERATING PROCEDURES

DESCRIPTION

Criteria to evaluate and inspect EOPs by the regions were prepared by NRR and OIE and published as an OIE Temporary Instruction (TI). Similar criteria and inspection modules were to be developed when the guidelines for the upgrading of other procedures were completed.

In December 1982, Supplement 1 to NUREG-0737[98] was issued as Generic Letter 82-33[376] with a requirement for each plant to submit a Procedures Generation Package (PGP) as a part of the effort to upgrade EOPs; the generic letter also indicated that the NRC would audit upgraded EOPs on a selective basis. In 1984, the NRC began auditing upgraded EOPs. After conducting several audits, the staff issued Information Notice No. 86-64[1210] to advise the industry that there were indications that many licensees were not appropriately developing and implementing upgraded EOPs. Based on the deficiencies identified in the Information Notice, the staff concluded that some licensees might not have appropriately developed and implemented upgraded EOPs in accordance with their PGPs. The staff decided to: (1) continue with its audit program to further determine the scope and safety significance of the deficiencies identified in the Notice;[1210] and (2) conduct inspections at all plants to evaluate the implementation of licensee commitments to develop and implement upgraded EOPs.

CONCLUSION

This issue was given a high priority ranking and pursued by the staff. In June 1986, the staff prepared TI 2515/79 which contained criteria for inspecting how well licensees were complying with their PGP commitments. In April 1987, the staff issued a supplement to its first Information Notice[1210] based on evaluations from 6 additional plants. In early 1988, the staff suspended its program to evaluate licensees' compliance with programmatic requirements (i.e., PGPs) and redirected its efforts to focus more on the technical adequacy and useability of the EOPs. Lessons learned by the staff from its inspection program for EOPs were published in NUREG-1358.[1209] TI 2515/92,[1209] "Emergency Operating Procedures Team Inspections," contains guidance for conducting these inspections. Based on the results from this inspection program of 28 plants, NRR was responsible for

developing a program of inspections for the remaining plants. Thus, this issue was RESOLVED and no new requirements were established.[1208]

ITEM HF4.2: PROCEDURES GENERATION PACKAGE EFFECTIVENESS EVALUATION

DESCRIPTION

To evaluate the effectiveness of the NRC's long-term program for upgrading EOPs, the staff audited the implementation of PGPs at selected plants. PGPs describe a plant's program for adapting generic technical guidelines to develop the technical content of plant-specific EOPs and applying human factors principles to produce EOPs that are useable by operators. Six audits were performed and additional audits were planned before an assessment of the program was completed. Based on input from sources including PGP implementation audits, staff PGP reviews, and license examiners, the staff identified problems that plants were experiencing with implementing their PGPs. To alert the industry to these problems, the staff issued Information Notice No. 86-64.[1210] Progress by the industry in addressing the problems identified in the Notice were to be monitored by inspections, additional PGP implementation audits, and through continued dialogue with the industry.

CONCLUSION

This item was related to increasing the staff's knowledge, certainty, and understanding of safety issues in order to increase its confidence in assessing levels of safety and, therefore, was classified as a Licensing Issue.

ITEM HF4.3: CRITERIA FOR SAFETY-RELATED OPERATOR ACTIONS

DESCRIPTION

A safety evaluation standard was to be developed to screen licensee proposals to place additional burdens upon operators. Licensees proposing to resolve severe accident issues or other generic safety issues by adding to EOPs and training, in lieu of hardware fixes, were expected to utilize the standard to verify that the additional burdens placed upon operators did not overload the operators, and that the additional operator responsibilities were adequately covered in procedures and training. This standard was to be applied to any licensee proposing to add additional operator responsibilities as part of the resolution of a generic safety issue; the staff did not anticipate that it would be applied retroactively to DBAs or existing EOPs. The standard would not impose requirements upon plant design or operation directly, but could narrow the range of options available to resolve other issues. The likely form of the standard was believed to be an SRP[11] Section.

CONCLUSION

This item was covered in Issue B-17.

ITEM HF4.4: GUIDELINES FOR UPGRADING OTHER PROCEDURES

DESCRIPTION

On the basis of efforts to evaluate the quality of, and the problems associated with, existing plant procedures, NRR evaluated the need to develop technical guidance for use by the industry in upgrading normal operating procedures and abnormal operating procedures (AOPs) similar to what the staff completed for EOPs. The staff was to perform a regulatory analysis to determine whether regulatory action for other plant procedures was warranted and, if so, develop formal regulatory requirements.

CONCLUSION

This issue was given a high priority ranking and RESOLVED with no new requirements.[1562] The staff prepared a summary of good practices that licensees could use in performing any voluntary upgrade of procedures.[1576] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

ITEM HF4.5: APPLICATION OF AUTOMATION AND ARTIFICIAL INTELLIGENCE

DESCRIPTION

The level of automation possible within the nuclear industry spans a range of possibilities from the fully manual, with locally operated valves, to the fully automated, employing artificial intelligence (AI). The nuclear industry is basically at the one-switch one-valve end of that range. The reliability of AI for safety-related uses was unproven; however, evidence from other industries suggested that there can be significant savings in operating costs as well as an enhancement in safety with increased automation of operator actions. Reducing the menial level workload of operators could provide better low-level control and fewer operator errors. Such automation can also free operators to concentrate on the cognitive level of operations. The subject of automation and AI affects control room design, operating procedures, and other operator aids, staffing, and training. The staff was to investigate the benefits and hazards of increased automation in the nuclear industry and consider incentives to encourage the movement toward automation as a means of increasing plant safety.

CONCLUSION

This item was covered in Item HF5.2.

REFERENCES

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

98. NUREG-0737, "Clarification of TMI Action Plan Requirements," U.S. Nuclear Regulatory Commission, November 1980, (Supplement 1) January 1983.

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

1208. Memorandum for V. Stello from T. Murley, "Final Resolution of Generic Issue (GI) HF4.1, Inspection Procedure for Upgraded Emergency Operating Procedures," October 17, 1988.

1209. NUREG-1358, "Lessons Learned from the Special Inspection Program for Emergency Operating Procedures," U.S. Nuclear Regulatory Commission, April 1989.

1210. NRC Information Notice No. 86-64, "Deficiencies in Upgrade Programs for Plant Emergency Operating Procedures," August 14, 1986, (Supplement 1) April 20, 1987.

1562. Memorandum for J. Taylor from E. Beckjord, "Resolution of Human Factors Generic Issue 4.4, 'Guidelines for Upgrading Other Procedures,'" July 29, 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

1576. "Approaches to Upgrading Procedures in Nuclear Power Plants," Pacific Northwest Laboratory, August 1994.

TASK HF5: MAN-MACHINE INTERFACE

The objective of this task was to ensure that the man-machine interface (MMI) is adequate for the safe operation and maintenance of nuclear power plants. This objective was to be attained by developing: (1) human factors engineering guidelines for correcting MMI problems; and (2) regulatory guidance for integrating human factors engineering into new designs and into advanced technological improvements incorporated into existing designs. This task was also to provide for the preparation of evaluation tools for: (1) the next generation of nuclear power plants; and (2) expected changes or upgrading to designed plants in the area of data and information management and improved annunciator systems. These efforts were expected to improve the staff's capability to evaluate reactor incidents involving MMI errors. This task was identified as four distinct items in Table 7 of the NRC 1985 Annual Report (Items 5.1, 5.2, 5.3, and 5.4). The following is a discussion of these four items.

ITEM HF5.1: LOCAL CONTROL STATIONS

DESCRIPTION

Previous regulatory efforts dealing with the MMI were limited to the control room and remote shutdown panel. It was believed that further guidance regarding local control stations and auxiliary operator interfaces was necessary as well as additional guidance regarding improvements to existing annunciator systems.

Information was to be developed to determine if guidance on local control station design and auxiliary operator interfaces with these stations was required. To accomplish this task, job/task analyses of control room crew activities were to be conducted to identify and describe communication and control links between the control room and the auxiliary control stations. In addition, the functions of the auxiliary personnel were to be analyzed from the task analyses to estimate the potential impact of auxiliary personnel job errors on plant safety.

CONCLUSION

The issue was given a high priority ranking and a survey of safety-significant local control stations was conducted at 4 plants. This survey included remote shutdown panels, local diesel generator panels, and local ECCS panels. Deficiencies found were poor lighting, poor labeling, obstructed view of instrumentation, and unavailable communication equipment. The survey was documented in NUREG/CR-3696.[1521]

A preliminary value/impact analysis that considered various combinations of upgrades involving panel re-design as well as functional centralization was completed and documented in NUREG/CR-5572.[1524] However, with the publication of NUREG-1150,[1081] the potential risk reduction was found to be considerably lower than previously anticipated and work was curtailed. The staff's studies were published in NUREG/CR-6146.[1577] Thus, this issue was RESOLVED and no new requirements were established.[1525] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

ITEM HF5.2: REVIEW CRITERIA FOR HUMAN FACTORS ASPECTS OF ADVANCED CONTROLS AND INSTRUMENTATION

DESCRIPTION

The existing human engineering guidelines for nuclear power plant control rooms primarily addressed the control, display, and information concepts and technologies that were being used in process control systems. While these guidelines were adequate for the existing generation of nuclear power plants, the staff did not believe that they were sufficient for advanced and developing technologies that could be introduced into existing and future designs. Improved annunciator systems utilizing advanced technologies were expected to become available and guidelines for the utilization and evaluation of these longer-term annunciator improvements were to be developed, based on evaluations of results from advanced concept activities performed by governmental and commercially-sponsored research activities.

Thus, this issue focused on the potential risk that could result from the human error in the use of control room annunciators and included consideration of Items HF4.5 (automation and artificial intelligence), HF5.3 (operational aids), and HF5.4 (computers and computer displays). Proposed solutions to this combined issue were to be changes to the SRP,[11] industry guidance such as a Regulatory Guide, and development of the necessary staff expertise to evaluate proposed designs for the MMI based on advanced technology.

CONCLUSION

This issue was given a high priority ranking and work was undertaken to determine the potential public risk from human error in the use of information from control room annunciators and to assess the safety significance of upgrades identified in studies documented in NUREG/CR-3217[1522] and NUREG/CR-3987.[1523] However, work on this issue was terminated[1526] when the development of review guidance for advanced annunciators was integrated into an existing RES program to develop an "Advanced Human-Interface Design Review Guideline." The review guidance was later published in NUREG/CR-6105.[1578] In an RES evaluation,[1564] it was concluded that consideration of a 20-year license renewal period did not affect the resolution.

ITEM HF5.3: EVALUATION OF OPERATIONAL AID SYSTEMS

DESCRIPTION

Staff guidance pertinent to MMI involving new control and display techniques were to be prepared to include: (1) identification of new and developing display and control technologies having a potential application in nuclear power plant control rooms; (2) development of evaluating methods and design criteria related to visual displays; and (3) establishment of the criteria needed for regulatory assessment of advanced control room concepts. In addition, the control and display requirements for crew response needs following a seismic event were to be identified.

Based on the results of an investigation of means for monitoring and verifying operations, test, and maintenance activities, the staff was to make determinations concerning: (1) the comparative adequacy of status monitoring in

plants that did not have automatic monitoring systems; (2) the adequacy of operational systems designed to be in conformance with Regulatory Guide 1.47[150]; and (3) the development of long-term improvement guidance addressing the feasibility and value/impact of instrumentation backfits.

CONCLUSION

This issue was covered in Item HF5.2.

ITEM HF5.4: COMPUTERS AND COMPUTER DISPLAYS

DESCRIPTION

A program plan will be developed to evaluate the safety significance and problems relating to the management of data and information in the nuclear power plant control room during abnormal events. Products may include the development of guidelines on control room information management during severe transients and accidents. These guidelines may be in the form of NUREG reports and Regulatory Guides.

CONCLUSION

This issue was covered in Item HF5.2.

REFERENCES

11. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (1st Edition) November 1975, (2nd Edition) March 1980, (3rd Edition) July 1981.

150. Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems," U.S. Nuclear Regulatory Commission, May 1973.

1081. NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants," U.S. Nuclear Regulatory Commission, (Vol. 1) December 1990, (Vol. 2) December 1990, (Vol. 3) January 1991.

1521. NUREG/CR-3696, "Potential Human Factors Deficiencies in the Design of Local Control Stations and Operator Interfaces in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, April 1984.

1522. NUREG/CR-3217, "Near-Term Improvements for Nuclear Power Plant Control Room Annunciator Systems," U.S. Nuclear Regulatory Commission, April 1983.

1523. NUREG/CR-3987,"Computerized Annunciator Systems," U.S. Nuclear Regulatory Commission, June 1985.

1524. NUREG/CR-5572, "An Evaluation of the Effects of Local Control Station Design Configurations on Human Performance and Nuclear Power Plant Risk," U.S. Nuclear Regulatory Commission, September 1990.

1525. Memorandum for J. Taylor from E. Beckjord, "Termination of Work on Generic Safety Issue HF5.1 'Local Control Stations,'" June 29, 1993.

1526. Memorandum for J. Taylor from E. Beckjord, "Resolution of Human Factors Generic Issue 5.2, 'Review Criteria for Human Factors Aspects of Advanced Controls and Instrumentation,'" June 29. 1993.

1564. Memorandum for W. Russell from E. Beckjord, "License Renewal Implications of Generic Safety Issues (GSIs) Prioritized and/or Resolved Between October 1990 and March 1994," May 5, 1994.

1577. NUREG/CR-6146, "Local Control Stations: Human Engineering Issues and Insights," U.S. Nuclear Regulatory Commission, September 1994.

1578. NUREG/CR-6105, "Human Factors Engineering Guidance for the Review of Advanced Alarm Systems," U.S. Nuclear Regulatory Commission, September 1994.

APPENDIX B
APPLICABILITY OF NUREG-0933 ISSUES TO OPERATING AND FUTURE PLANTS

This appendix contains a listing of those residual GSIs that are applicable to operating and future plants and includes: issues that have been resolved with requirements [NOTE 3(a), I]; USI, HIGH- and MEDIUM-priority issues scheduled for resolution; nearly-resolved issues scheduled for resolution (NOTES 1 and 2); and issues that are scheduled for prioritization (NOTE 4). The priority designations for all issues are consistent with those listed in Table II of the Introduction. In accordance with 10 CFR 52.47(a)(1)(iv), any future application for design certification must contain proposed technical resolutions for the issues in this listing that are designated USI, HIGH, MEDIUM, NOTE 1, and NOTE 2. Also included in this listing are those GSIs that were either prioritized or resolved with no impact on operating plants, but contain recommendations for future plants (NOTE 6).

Legend

NOTES:	1	- Possible Resolution Identified for Evaluation
	2	- Resolution Available (Documented in NUREG, NRC Memorandum, SER or equivalent)
	3(a)	- Resolution Resulted in the Establishment of New Regulatory Requirements (Rule, Regulatory Guide, SRP Change, or equivalent)
	4	- Issue to be Prioritized in the Future
	6	- New Requirements for Future Plants Recommended
B&W		- Babcock & Wilcox Company
CE		- Combustion Engineering Company
GE		- General Electric Company
HIGH		- High Safety Priority
I		- Resolved TMI Action Plan Item with Implementation of Resolution Mandated by NUREG-0737
MEDIUM		- Medium Safety Priority
MPA		- Multiplant Action
NA		- Not Applicable
TBD		- To Be Determined
USI		- Unresolved Safety Issue
W		- Westinghouse Electric Corporation

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
		TMI ACTION PLAN ITEMS					
I.A	OPERATING PERSONNEL						
I.A.1	Operating Personnel and Staffing						
I.A.1.1	Shift Technical Advisor	I	All	All	F-01	09/13/79	09/27/79
I.A.1.2	Shift Supervisor Administrative Duties	I	All	All		09/13/79	09/27/79
I.A.1.3	Shift Manning	I	All	All	F-02	07/31/80	06/26/80
I.A.1.4	Long-Term Upgrading	NOTE 3(a)	All	All		04/28/83	04/28/83
I.A.2	Training and Qualifications of Operating Personnel						
I.A.2.1	Immediate Upgrading of Operator and Senior Operator Training and Qualifications	-					
I.A.2.1(1)	Qualifications - Experience	I	All	All	F-03	03/28/80	03/28/80
I.A.2.1(2)	Training	I	All	All	F-03	03/28/80	03/28/80
I.A.2.1(3)	Facility Certification of Competence and Fitness of Applicants for Operator and Senior Operator Licenses	I	All	All	F-03	03/28/80	03/28/80
I.A.2.3	Administration of Training Programs	I	All	All		03/28/80	03/28/80
I.A.2.6	Long-Term Upgrading of Training and Qualifications	-	-	-		-	-
I.A.2.6(1)	Revise Regulatory Guide 1.8	NOTE 3(a)	All	All		TBD	05/--/87
I.A.3	Licensing and Requalification of Operating Personnel						
I.A.3.1	Revise Scope of Criteria for Licensing Examinations	I	All	All		03/28/80	03/28/80
I.A.4	Simulator Use and Development						
I.A.4.1	Initial Simulator Improvement	-					
I.A.4.1(2)	Interim Changes in Training Simulators	NOTE 3(a)	All	All		04/--/81	03/28/81
I.A.4.2	Long-Term Training Simulator Upgrade	-					
I.A.4.2(1)	Research on Training Simulators	NOTE 3(a)	All	All		04/--/87	04/--/87
I.A.4.2(2)	Upgrade Training Simulator Standards	NOTE 3(a)	All	All		04/--/81	04/--/81
I.A.4.2(3)	Regulatory Guide on Training Simulators	NOTE 3(a)	All	All		04/--/81	04/--/81
I.A.4.2(4)	Review Simulators for Conformance to Criteria	NOTE 3(a)	All	All		03/25/87	03/25/87
I.C	OPERATING PROCEDURES						
I.C.1	Short-Term Accident Analysis and Procedures Revision	-					
I.C.1(1)	Small Break LOCAs	I	All	All		09/13/79	09/13/79
I.C.1(2)	Inadequate Core Cooling	I	All	All	F-04	09/13/79	09/13/79
I.C.1(3)	Transients and Accidents	I	All	All	F-05	09/13/79	09/27/79
I.C.2	Shift and Relief Turnover Procedures	I	All	All		09/13/79	09/27/79
I.C.3	Shift Supervisor Responsibilities	I	All	All		09/13/79	09/27/79
I.C.4	Control Room Access	I	All	All		09/13/79	09/27/79
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	I	All	All	F-06	05/07/80	06/26/80

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	Affected NSSS Vendor PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	I	All	All	F-07	10/31/80	10/31/80
I.C.7	NSSS Vendor Review of Procedures	I	All	All		NA	06/26/80
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	I	All	All		NA	06/26/80
I.C.9	Long-Term Program Plan for Upgrading of Procedures	NOTE 3(a)	All	All		09/13/79	06/--/85
I.D	CONTROL ROOM DESIGN						
I.D.1	Control Room Design Reviews	I	All	All	F-08	06/26/80	06/26/80
I.D.2	Plant Safety Parameter Display Console	I	All	All	F-09	06/26/80	06/26/80
I.D.5	Improved Control Room Instrumentation Research	-					
I.D.5(2)	Plant Status and Post-Accident Monitoring	NOTE 3(a)	All	All		NA	12/--/80
I.F	QUALITY ASSURANCE						
I.F.2	Develop More Detailed QA Criteria	-					
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	NOTE 3(a)	All	All		NA	07/--/81
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	NOTE 3(a)	All	All		NA	07/--/81
I.F.2(6)	Increase the Size of Licensees' QA Staff	NOTE 3(a)	All	All		NA	07/--/81
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	NOTE 3(a)	All	All		NA	07/--/81
I.G	PREOPERATIONAL AND LOW-POWER TESTING						
I.G.1	Training Requirements	I	All	All		NA	06/26/80
I.G.2	Scope of Test Program	NOTE 3(a)	All	All		NA	07/--/81
II.B	CONSIDERATION OF DEGRADED OR MELTED CORES IN SAFETY REVIEW						
II.B.1	Reactor Coolant System Vents	I	All	All	F-10	09/13/79	09/27/79
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	I	All	All	F-11	09/13/79	09/27/79
II.B.3	Post-Accident Sampling	I	All	All	F-12	09/13/79	09/27/79
II.B.4	Training for Mitigating Core Damage	I	All	All	F-13	03/28/80	03/28/80
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	NOTE 3(a)	All	All		TBD	NA
II.B.8	Rulemaking Proceeding on Degraded Core Accidents	NOTE 3(a)	All	All		TBD	01/25/85
II.D	REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES						
II.D.1	Testing Requirements	I	All	All	F-14	09/13/79	09/27/79
II.D.3	Relief and Safety Valve Position Indication	I	All	All		07/21/79	09/27/79

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
II.E	SYSTEM DESIGN						
II.E.1	Auxiliary Feedwater System						
II.E.1.1	Auxiliary Feedwater System Evaluation	I	NA	All	F15	03/10/80	03/10/80
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	I	NA	All	F-16, F-17	09/13/79	09/27/79
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	NOTE 3(a)	All	All		NA	07/--/81
II.E.3	Decay Heat Removal						
II.E.3.1	Reliability of Power Supplies for Natural Circulation	I	NA	All		09/13/79	09/27/79
II.E.4	Containment Design						
II.E.4.1	Dedicated Penetrations	I	All	All	F-18	09/13/79	09/27/79
II.E.4.2	Isolation Dependability	I	All	All	F-19	09/13/79	09/27/79
II.E.4.4	Purging	-					
II.E.4.4(1)	Issue Letter to Licensees Requesting Limited Purging	NOTE 3(a)	All	All		11/28/78	NA
II.E.4.4(2)	Issue Letter to Licensees Requesting Information on Isolation Letter	NOTE 3(a)	All	All		10/22/79	NA
II.E.4.4(3)	Issue Letter to Licensees on Valve Operability	NOTE 3(a)	All	All		09/27/79	NA
II.E.5	Design Sensitivity of B&W Reactors						
II.E.5.1	Design Evaluation	NOTE 3(a)	NA	B&W			
II.E.5.2	B&W Reactor Transient Response Task Force	NOTE 3(a)	NA	B&W			
II.E.6	In Situ Testing of Valves						
II.E.6.1	Test Adequacy Study	NOTE 3(a)	All	All		06/--/89	06/--/89
II.F	INSTRUMENTATION AND CONTROLS						
II.F.1	Additional Accident Monitoring Instrumentation	I	All	All	F-20, F-21 F-22, F-23 F-24, F-25	09/13/79	09/27/79
II.F.2	Identification of and Recovery from Conditions Leading to Inadequate Core Cooling	I	All	All	F-26	070/2/79	09/27/79
II.F.3	Instruments for Monitoring Accident Conditions	NOTE 3(a)	All	All		NA	12/--/80
II.G	ELECTRICAL POWER						
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	I	NA	All		09/13/79	09/27/79

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
II.J	GENERAL IMPLICATIONS OF TMI FOR DESIGN AND CONSTRUCTION ACTIVITIES						
II.J.4	Revise Deficiency Reporting Requirements						
II.J.4.1	Revise Deficiency Reporting Requirements	NOTE 3(a)	All	All		07/31/91	07/31/91
II.K	MEASURES TO MITIGATE SMALL-BREAK LOSS-OF-COOLANT ACCIDENTS AND LOSS-OF-FEEDWATER ACCIDENTS						
II.K.1	IE Bulletins	-					
II.K.1(1)	Review TMI-2 PNs and Detailed Chronology of the TMI-2 Accident	NOTE 3(a)	All	All		03/31/80	NA
II.K.1(2)	Review Transients Similar to TMI-2 That Have Occurred at Other Facilities and NRC Evaluation of Davis-Besse Event	NOTE 3(a)	NA	B&W		03/31/80	NA
II.K.1(3)	Review Operating Procedures for Recognizing, Preventing, and Mitigating Void Formation in Transients and Accidents	NOTE 3(a)	NA	All		03/31/80	NA
II.K.1(4)	Review Operating Procedures and Training Instructions	NOTE 3(a)	All	All		03/31/80	NA
II.K.1(5)	Safety-Related Valve Position Description	NOTE 3(a)	All	All		03/31/80	03/31/80
II.K.1(6)	Review Containment Isolation Initiation Design and Procedures	NOTE 3(a)	All	All		03/31/80	NA
II.K.1(7)	Implement Positive Position Controls on Valves That Could Compromise or Defeat AFW Flow	NOTE 3(a)	NA	B&W		03/31/80	NA
II.K.1(8)	Implement Procedures That Assure Two Independent 100% AFW Flow Paths	NOTE 3(a)	NA	B&W		03/31/80	NA
II.K.1(9)	Review Procedures to Assure That Radioactive Liquids and Gases Are Not Transferred out of Containment Inadvertently	NOTE 3(a)	All	All		03/31/80	NA
II.K.1(10)	Review and Modify Procedures for Removing Safety-Related Systems from Service	NOTE 3(a)	All	All		03/31/80	03/31/80
II.K.1(11)	Make All Operating and Maintenance Personnel Aware of the Seriousness and Consequences of the Erroneous Actions Leading up to, and in Early Phases of, the TMI-2 Accident	NOTE 3(a)	All	All		03/31/80	NA
II.K.1(12)	One Hour Notification Requirement and Continuous Communications Channels	NOTE 3(a)	All	All			NA
II.K.1(13)	Propose Technical Specification Changes Reflecting Implementation of All Bulletin Items	NOTE 3(a)	All	All		01/01/81	01/01/81
II.K.1(14)	Review Operating Modes and Procedures to Deal with Significant Amounts of Hydrogen	NOTE 3(a)	GE	CE, W		03/31/80	NA
II.K.1(15)	For Facilities with Non-Automatic AFW Initiation, Provide Dedicated Operator in Continuous Communication with CR to Operate AFW	NOTE 3(a)	NA	CE, W			NA

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
II.K.1(16)	Implement Procedures That Identify PRZ PORV "Open" Indications and That Direct Operator to Close Manually at "Reset" Setpoint	NOTE 3(a)	NA	CE, W			NA
II.K.1(17)	Trip PZR Level Bistable so That PZR Low Pressure Will Initiate Safety Injection	NOTE 3(a)	NA	W			
II.K.1(18)	Develop Procedures and Train Operators on Methods of Establishing and Maintaining Natural Circulation	NOTE 3(a)	NA	B&W			NA
II.K.1(19)	Describe Design and Procedure Modifications to Reduce Likelihood of Automatic PZR PORV Actuation in Transients	NOTE 3(a)	NA	B&W		03/31/80	NA
II.K.1(20)	Provide Procedures and Training to Operators for Prompt Manual Reactor Trip for LOFW, TT, MSIV Closure, LOOP, LOSG Level, and LO PZR Level	NOTE 3(a)	NA	B&W		03/31/80	03/31/80
II.K.1(21)	Provide Automatic Safety-Grade Anticipatory Reactor Trip for LOFW, TT, or Significant Decrease in SG Level	NOTE 3(a)	NA	B&W		03/31/80	03/31/80
II.K.1(22)	Describe Automatic and Manual Actions for Proper Functioning of Auxiliary Heat Removal Systems When FW System Not Operable	NOTE 3(a)	All	NA		03/31/80	03/31/80
II.K.1(23)	Describe Uses and Types of RV Level Indication for Automatic and Manual Initiation Safety Systems	NOTE 3(a)	All	NA		03/31/80	03/31/80
II.K.1(24)	Perform LOCA Analyses for a Range of Small-Break Sizes and a Range of Time Lapses Between Reactor Trip and RCP Trip	NOTE 3(a)	NA	All		NA	
II.K.1(25)	Develop Operator Action Guidelines	NOTE 3(a)	NA	All		NA	
II.K.1(26)	Revise Emergency Procedures and Train ROs and SROs	NOTE 3(a)	NA	All		NA	
II.K.1(27)	Provide Analyses and Develop Guidelines and Procedures for Inadequate Core Cooling Conditions	NOTE 3(a)	NA	All		NA	
II.K.1(28)	Provide Design That Will Assure Automatic RCP Trip for All Circumstances Where Required	NOTE 3(a)	NA	All		01/01/81	01/01/82
II.K.2	Commission Orders on B&W Plants	-					
II.K.2(1)	Upgrade Timeliness and Reliability of AFW System	NOTE 3(a)	NA	B&W		NA	
II.K.2(2)	Procedures and Training to Initiate and Control AFW Independent of Integrated Control System	NOTE 3(a)	NA	B&W		NA	
II.K.2(3)	Hard-Wired Control-Grade Anticipatory Reactor Trips	NOTE 3(a)	NA	B&W		NA	
II.K.2(4)	Small-Break LOCA Analysis, Procedures and Operator Training	NOTE 3(a)	NA	B&W		NA	
II.K.2(5)	Complete TMI-2 Simulator Training for All Operators	NOTE 3(a)	NA	B&W		NA	
II.K.2(6)	Reevaluate Analysis for Dual-Level Setpoint Control	NOTE 3(a)	NA	B&W		NA	
II.K.2(7)	Reevaluate Transient of September 24, 1977	NOTE 3(a)	NA	B&W		NA	
II.K.2(9)	Analysis and Upgrading of Integrated Control System	I	NA	B&W	F-27	01/01/81	01/01/81
II.K.2(10)	Hard-Wired Safety-Grade Anticipatory Reactor Trips	I	NA	B&W	F-28	01/01/81	01/01/81
II.K.2(11)	Operator Training and Drilling	I	NA	B&W	F-29	01/01/81	01/01/81
II.K.2(13)	Thermal-Mechanical Report on Effect of HPI on Vessel Integrity for Small-Break LOCA With No AFW	I	NA	B&W	F-30	01/01/81	01/01/81

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
II.K.2(14)	Demonstrate That Predicted Lift Frequency of PORVs and SVs Is Acceptable	I	NA	B&W	F-31	01/01/81	01/01/81
II.K.2(15)	Analysis of Effects of Slug Flow on Once-Through Steam Generator Tubes After Primary System Voiding	I	NA	B&W		06/01/80	06/01/80
II.K.2(16)	Impact of RCP Seal Damage Following Small-Break LOCA With Loss of Offsite Power	I	NA	B&W	F-32	06/01/80	06/01/80
II.K.2(17)	Analysis of Potential Voiding in RCS During Anticipated Transients	I	NA	B&W	F-33		NA
II.K.2(19)	Benchmark Analysis of Sequential AFW Flow to Once-Through Steam Generator	I	NA	B&W	F-34	01/01/81	NA
II.K.2(20)	Analysis of Steam Response to Small-Break LOCA That Causes System Pressure to Exceed PORV Setpoint	I	NA	B&W	F-35	01/01/81	NA
II.K.2(21)	LOFT L3-1 Predictions	NOTE 3(a)	NA	B&W			NA
II.K.3	Final Recommendations of Bulletins and Orders Task Force	-					
II.K.3(1)	Install Automatic PORV Isolation System and Perform Operational Test	I	NA	All	F-36	07/01/81	07/01/81
II.K.3(2)	Report on Overall Safety Effect of PORV Isolation System	I	NA	All	F-37	01/01/81	01/01/81
II.K.3(3)	Report Safety and Relief Valve Failures Promptly and Challenges Annually	I	All	All	F-38	04/01/80	04/01/80
II.K.3(5)	Automatic Trip of Reactor Coolant Pumps	I	NA	All	F-39, G-01	01/01/81	01/01/81
II.K.3(7)	Evaluation of PORV Opening Probability During Overpressure Transient	I	NA	B&W		01/01/81	01/01/81
II.K.3(9)	Proportional Integral Derivative Controller Modification	I	NA	W	F-40	07/01/80	07/01/80
II.K.3(10)	Anticipatory Trip Modification Proposed by Some Licensees to Confine Range of Use to High Power Levels	I	NA	W	F-41		
II.K.3(11)	Control Use of PORV Supplied by Control Components, Inc. Until Further Review Complete	I	All	All			
II.K.3(12)	Confirm Existence of Anticipatory Trip Upon Turbine Trip	I	NA	W	F-42	07/01/80	07/01/80
II.K.3(13)	Separation of HPCI and RCIC System Initiation Levels	I	GE	NA	F-43	10/01/80	10/01/80
II.K.3(14)	Isolation of Isolation Condensers on High Radiation	I	GE	NA	F-44	01/01/81	NA
II.K.3(15)	Modify Break Detection Logic to Prevent Spurious Isolation of HPCI and RCIC Systems	I	GE	NA	F-45	01/01/81	01/01/81
II.K.3(16)	Reduction of Challenges and Failures of Relief Valves - Feasibility Study and System Modification	I	GE	NA	F-46	01/01/81	01/01/81
II.K.3(17)	Report on Outage of ECC Systems - Licensee Report and Technical Specification Changes	I	GE	NA	F-47	01/01/81	01/01/81
II.K.3(18)	Modification of ADS Logic - Feasibility Study and Modification for Increased Diversity for Some Event Sequences	I	GE	NA	F-48	01/01/81	01/01/81
II.K.3(19)	Interlock on Recirculation Pump Loops	I	GE	NA	F-49	01/01/81	NA
II.K.3(20)	Loss of Service Water for Big Rock Point	I	GE	NA		01/01/81	NA

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
II.K.3(21)	Restart of Core Spray and LPCI Systems on Low Level - Design and Modification	I	GE	NA	F-50	01/01/81	01/01/81
II.K.3(22)	Automatic Switchover of RCIC System Suction - Verify Procedures and Modify Design	I	GE	NA	F-51	01/01/81	01/01/81
II.K.3(24)	Confirm Adequacy of Space Cooling for HPCI and RCIC Systems	I	GE	NA	F-52	01/01/82	01/01/82
II.K.3(25)	Effect of Loss of AC Power on Pump Seals	I	GE	NA	F-53	01/01/82	01/01/82
II.K.3(27)	Provide Common Reference Level for Vessel Level Instrumentation	I	GE	NA	F-54	10/01/80	10/01/80
II.K.3(28)	Study and Verify Qualification of Accumulators on ADS Valves	I	GE	NA	F-55	01/01/82	01/01/82
II.K.3(29)	Study to Demonstrate Performance of Isolation Condensers with Non-Condensibles	I	GE	NA	F-56	04/01/81	NA
II.K.3(30)	Revised Small-Break LOCA Methods to Show Compliance with 10 CFR 50, Appendix K	I	All	All	F-57	01/01/83	01/01/83
II.K.3(31)	Plant-Specific Calculations to Show Compliance with 10 CFR 50.46	I	All	All	F-58	01/01/83	01/01/83
II.K.3(44)	Evaluation of Anticipated Transients with Single Failure to Verify No Significant Fuel Failure	I	GE	NA	F-59	01/01/81	01/01/81
II.K.3(45)	Evaluate Depressurization with Other Than Full ADS	I	GE	NA	F-60	01/01/81	01/01/81
II.K.3(46)	Response to List of Concerns from ACRS Consultant	I	GE	NA	F-61	07/01/80	07/01/80
II.K.3(57)	Identify Water Sources Prior to Manual Activation of ADS	I	GE	NA	F-62	10/01/80	NA
III.A	EMERGENCY PREPAREDNESS AND RADIATION EFFECTS						
III.A.1	Improve Licensee Emergency Preparedness - Short Term						
III.A.1.1	Upgrade Emergency Preparedness	-					
III.A.1.1(1)	Implement Action Plan Requirements for Promptly Improving Licensee Emergency Preparedness	I	All	All		10/10/79	08/19/80
III.A.1.2	Upgrade Licensee Emergency Support Facilities	-					
III.A.1.2(1)	Technical Support Center	I	All	All	F-63	09/13/79	09/27/79
III.A.1.2(2)	On-Site Operational Support Center	I	All	All	F-64	09/13/79	09/27/79
III.A.1.2(3)	Near-Site Emergency Operations Facility	I	All	All	F-65	09/13/79	09/27/79
III.A.2	Improving Licensee Emergency Preparedness-Long Term						
III.A.2.1	Amend 10 CFR 50 and 10 CFR 50, Appendix E	-					
III.A.2.1(1)	Publish Proposed Amendments to the Rules	NOTE 3(a)	All	All			
III.A.2.1(4)	Revise Inspection Program to Cover Upgraded Requirements	I	All	All	F-67		
III.A.2.2	Development of Guidance and Criteria	I	All	All	F-68		
III.A.3	Improving NRC Emergency Preparedness						
III.A.3.3	Communications	-					
III.A.3.3(1)	Install Direct Dedicated Telephone Lines	NOTE 3(a)	All	All			

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
III.A.3.3(2)	Obtain Dedicated, Short-Range Radio Communication Systems	NOTE 3(a)	All	All			
III.D	RADIATION PROTECTION						
III.D.1	Radiation Source Control						
III.D.1.1	Primary Coolant Sources Outside the Containment Structure	-					
III.D.1.1(1)	Review Information Submitted by Licensees Pertaining to Reducing Leakage from Operating Systems	I	All	All		07/02/79	09/27/79
III.D.3	Worker Radiation Protection Improvement						
III.D.3.3	Inplant Radiation Monitoring	-					
III.D.3.3(1)	Issue Letter Requiring Improved Radiation Sampling Instrumentation	I	All	All	F-69	09/13/79	09/27/79
III.D.3.3(2)	Set Criteria Requiring Licensees to Evaluate Need for Additional Survey Equipment	NOTE 3(a)	All	All		09/13/79	09/27/79
III.D.3.3(3)	Issue a Rule Change Providing Acceptable Methods for Calibration of Radiation-Monitoring Instruments	NOTE 3(a)	All	All		09/13/79	09/27/79
III.D.3.3(4)	Issue a Regulatory Guide	NOTE 3(a)	All	All		09/13/79	09/27/79
III.D.3.4	Control Room Habitability	I	All	All	F-70	05/07/80	06/26/80
	TASK ACTION PLAN ITEMS						
A-1	Water Hammer (former USI)	NOTE 3(a)	All	All		NA	03/15/84
A-2	Asymmetric Blowdown Loads on Reactor Primary Coolant Systems (former USI)	NOTE 3(a)	NA	All	D-10	01/--/81	01/--/81
A-3	Westinghouse Steam Generator Tube Integrity (former USI)	NOTE 3(a)	NA	W		04/17/85	04/17/85
A-4	CE Steam Generator Tube Integrity (former USI)	NOTE 3(a)	NA	CE		04/17/85	04/17/85
A-5	B&W Steam Generator Tube Integrity (former USI)	NOTE 3(a)	NA	B&W		04/17/85	04/17/85
A-6	Mark I Short-Term Program (former USI)	NOTE 3(a)	GE	NA		12/--/77	NA
A-7	Mark I Long-Term Program (former USI)	NOTE 3(a)	GE	NA	D-01	08/--/82	08/--/82
A-8	Mark II Containment Pool Dyanmic Loads - Long Term Program (former USI)	NOTE 3(a)	GE	NA		08/--/81	08/--/81
A-9	ATWS (former USI)	NOTE 3(a)	All	All		06/26/84	06/26/84
A-10	BWR Feedwater Nozzle Cracking (former USI)	NOTE 3(a)	All	NA	B-25	11/--/80	11/--/80
A-11	Reactor Vessel Materials Toughness (former USI)	NOTE 3(a)	All	All		10/--/82	NA
A-12	Fracture Toughness of Steam Generator and Reactor Coolant Pump Supports (former USI)	NOTE 3(a)	NA	All		NA	TBD
A-13	Snubber Operability Assurance	NOTE 3(a)	All	All		1980	1980
A-16	Steam Effects on BWR Core Spray Distribution	NOTE 3(a)	GE	NA	D-12		NA
A-24	Qualification of Class 1E Safety Related Equipment (former USI)	NOTE 3(a)	All	All	B-60	08/--/81	08/--/81
A-25	Non-Safety Loads on Class 1E Power Sources	NOTE 3(a)	All	All			09/--/78
A-26	Reactor Vessel Pressure Transient Protection (former USI)	NOTE 3(a)	NA	All	B-04	09/--/78	09/--/78

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
A-28	Increase in Spent Fuel Pool Storage Capacity	NOTE 3(a)	All	All		04/17/78	NA
A-31	RHR Shutdown Requirements (former USI)	NOTE 3(a)	All	All		05/--/78	10/01/78
A-35	Adequacy of Offsite Power Systems	NOTE 3(a)	All	All		06/02/77	1980
A-36	Control of Heavy Loads Near Spent Fuel (former USI)	NOTE 3(a)	All	All	C-10, C-15	07/--/80	07/--/80
A-39	Determination of Safety Relief Valve Pool Dynamic Loads and Temperature Limits (former USI)	NOTE 3(a)	GE	NA		02/29/80	09/30/80
A-40	Seismic Design Criteria (former USI)	NOTE 3(a)	All	All		TBD	09/--/89
A-42	Pipe Cracks in Boiling Water Reactors (former USI)	NOTE 3(a)	All	NA	B-05	02/--/81	02/--/81
A-43	Containment Emergency Sump Performance (former USI)	NOTE 3(a)	NA	All		NA	11/--/85
A-44	Station Blackout (former USI)	NOTE 3(a)	All	All		TBD	06/--/88
A-46	Seismic Qualification of Equipment in Operating Plants (former USI)	NOTE 3(a)	All	All		02/--/87	NA
A-47	Safety Implications of Control Systems (former USI)	NOTE 3(a)	All	All		09/20/89	09/20/89
A-48	Hydrogen Control Measures and Effects of Hydrogen Burns on Safety Equipment	NOTE 3(a)	All	W		12/--/81	12/--/81
A-49	Pressurized Thermal Shock (former USI)	NOTE 3(a)	NA	All	A-21	TBD	07/--/85
B-10	Behavior of BWR Mark III Containments	NOTE 3(a)	GE	NA		NA	09/--/84
B-17	Criteria for Safety-Related Operator Actions	MEDIUM	All	All		TBD	TBD
B-36	Develop Design, Testing, and Maintenance Criteria for Atmosphere Cleanup System Air Filtration and Adsorption Units for Engineered Safety Feature Systems and for Normal Ventilation Systems	NOTE 3(a)	All	All			03/--/78
B-55	Improved Reliability of Target Rock Safety Relief Valves	MEDIUM	All	NA		TBD	TBD
B-56	Diesel Reliability	NOTE 3(a)	All	All	D-19	06/--/93	06/--/93
B-61	Allowable ECCS Equipment Outage Periods	MEDIUM	All	All		TBD	TBD
B-63	Isolation of Low Pressure Systems Connected to the Reactor Coolant Pressure Boundary	NOTE 3(a)	All	All		04/20/81	
B-64	Decommissioning of Reactors	NOTE 3(a)	All	All		06/27/88	NA
B-66	Control Room Infiltration Measurements	NOTE 3(a)	All	All		NA	07/--/81
C-1	Assurance of Continuous Long Term Capability of Hermetic Seals on Instrumentation and Electrical Equipment	NOTE 3(a)	All	All		05/27/80	05/27/80
C-10	Effective Operation of Containment Sprays in a LOCA	NOTE 3(a)	All	All		NA	
C-17	Interim Acceptance Criteria for Solidification Agents for Radioactive Solid Wastes	NOTE 3(a)	All	All		12/27/82	12/27/82
		NEW GENERIC ISSUES					
15.	Radiation Effects on Reactor Vessel Supports	HIGH	All	All		TBD	TBD
23.	Reactor Coolant Pump Seal Failures	HIGH	NA	All		TBD	TBD
24.	Automatic Emergency Core Cooling System Switch to Recirculation	MEDIUM	NA	All		TBD	TBD
25.	Automatic Air Header Dump on BWR Scram System	NOTE 3(a)	All	NA		01/09/81	01/09/81

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
40.	Safety Concerns Associated with Pipe Breaks in the BWR Scram System	NOTE 3(a)	All	NA	B-65	08/31/81	08/31/81
41.	BWR Scram Discharge Volume Systems	NOTE 3(a)	All	NA	B-58	12/09/80	NA
43.	Reliability of Air Systems	NOTE 3(a)	All	All		08/08/88	08/08/88
45.	Inoperability of Instrumentation Due to Extreme Cold Weather	NOTE 3(a)	All	All		NA	09/01/83
51.	Proposed Requirements for Improving the Reliability of Open Cycle Service Water Systems	NOTE 3(a)	All	All		07/18/89	07/18/89
67.	Steam Generator Staff Actions	-	-	-		-	-
67.3.3	Improved Accident Monitoring	NOTE 3(a)	All	All	A-17	12/17/82	12/17/82
70.	PORV and Block Valve Reliability	NOTE 3(a)	NA	All		06/25/90	06/25/90
73.	Detached Thermal Sleeves	NOTE 3(a)	NA	W			NA
75.	Generic Implications of ATWS Events at the Salem Nuclear Plant	NOTE 3(a)	All	All	B-76, B-77, B-78, B-79, B-80, B-81, B-82, B-85, B-86, B-87, B-88, B-89, B-90, B-91, B-92, B-93	07/08/83	TBD
78.	Monitoring of Fatigue Transient Limits for Reactor Coolant System	MEDIUM	All	All		TBD	TBD
83.	Control Room Habitability	NOTE 1	All	All		TBD	TBD
86.	Long Range Plan for Dealing with Stress Corrosion Cracking in BWR Piping	NOTE 3(a)	All	NA	B-84	TBD	TBD
87.	Failure of HPCI Steam Line Without Isolation	NOTE 3(a)	All	All		06/28/89	06/28/89
89.	Stiff Pipe Clamps	NOTE 6	All	All	NA	NA	TBD
93.	Steam Binding of Auxiliary Feedwater Pumps	NOTE 3(a)	NA	All		10/--/85	10/--/85
94.	Additional Low Temperature Overpressure Protection for Light Water Reactors	NOTE 3(a)	NA	CE, W		06/25/90	06/25/90
99.	RCS/RHR Suction Line Valve Interlock on PWRs	NOTE 3(a)	NA	All		10/17/88	10/17/88
103.	Design for Probable Maximum Precipitation	NOTE 3(a)	All	All		10/19/89	10/19/89
118.	Tendon Anchorage Failure	NOTE 3(a)	All	All	NA	NA	07/--/90
124.	Auxiliary Feedwater System Reliability	NOTE 3(a)	All	All		TBD	TBD
128.	Electrical Power Reliability	NOTE 3(a)	All	All		04/29/91	04/29/91
130.	Essential Service Water Pump Failures at Multiplant Sites	NOTE 3(a)	NA	All		09/19/91	09/19/91
155.	Generic Concerns Arising from TMI-2 Cleanup	-	-	-		-	-
155.1	More Realistic Source Term Assumptions	NOTE 3(a)	All	All	NA	NA	02/--/95
156.	Systematic Evaluation Program	-	-	-		-	-
156.6.1	Pipe Break Effects on Systems and Components	NOTE 4	All	All		TBD	TBD
158.	Performance of Power-Operated Valves Under Design Basis Conditions	MEDIUM	All	All		TBD	TBD
163.	Multiple Steam Generator Tube Leakage	NOTE 4	NA	All		TBD	TBD
165.	Safety and Safety/Relief Valve Reliability	HIGH	All	All		TBD	TBD
166.	Adequacy of Fatigue Life of Metal Components	NOTE 1	All	All		TBD	TBD

Appendix B (Continued)

Action Plan Item/ Issue No.	Title	Safety Priority/ Status	Affected NSSS Vendor BWR	PWR	Operating Plants- MPA No.	Operating Plants - Effective Date	Future Plants- Effective Date
168.	Environmental Qualification of Electrical Equipment	NOTE 1	All	All		TBD	TBD
169.	BWR MSIV Common Mode Failure Due to Loss of Accumulator Pressure	NOTE 4	All	NA		TBD	TBD
170.	Fuel Damage Criteria for High Burnup Fuel	NOTE 2	All	All		TBD	TBD
171.	ESF Failure from LOOP Subsequent to A LOCA	HIGH	All	All		TBD	TBD
		HUMAN FACTORS ISSUES					
HF1	STAFFING AND QUALIFICATIONS						
HF.1.1	Shift Staffing	NOTE 3(a)	All	All		01/--/84	01/--/84

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10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

The report presents the safety priority ranking for generic safety issues related to nuclear power plants. The purpose of these rankings is to assist in the timely and efficient allocation of NRC resources for the resolution of those safety issues that have a significant potential for reducing risk. The safety priority rankings are HIGH, MEDIUM, LOW, and DROP, and have been assigned on the basis of risk significance estimates, the ratio of risk to costs and other impacts estimated to result if resolution of the safety issues were implemented, and the consideration of uncertainties and other quantitative or qualitative factors. To the extent practical, estimates are quantitative.

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