UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

JUNE 2000

SUPPLEMENT 24 TO NUREG-0933
"A PRIORITIZATION OF GENERIC SAFETY ISSUES"

REVISION INSERTION INSTRUCTIONS

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TABLE II

LISTING OF ALL TMI ACTION PLAN ITEMS, TASK ACTION PLAN ITEMS, NEW GENERIC ISSUES, HUMAN FACTORS ISSUES, AND CHERNOBYL 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 Rev.	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	3	12/31/97	F-01
I.A.1.2	Shift Supervisor Administrative Duties	-	NRR/DHFS/LQB	I	3	12/31/97	
I.A.1.3	Shift Manning	-	NRR/DHFS/LQB	I	3	12/31/97	F-02
I.A.1.4	Long-Term Upgrading	Colmar	RES/DFO/HFBR	NOTE 3(a)	3	12/31/97	
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	6	12/31/97	F-03
I.A.2.1(2)	Training	-	NRR/DHFS/LQB	I	6	12/31/97	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	6	12/31/97	F-03
I.A.2.2	Training and Qualifications of Operations Personnel	Colmar	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	NA
I.A.2.3	Administration of Training Programs	-	NRR/DHFS/LQB	I	6	12/31/97	
I.A.2.4	NRR Participation in Inspector Training	Colmar	NRR/DHFS/LQB	LI (NOTE 3)	6	12/31/97	NA
I.A.2.5	Plant Drills	Colmar	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	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)	6	12/31/97	NA
I.A.2.6(2)	Staff Review of NRR 80-117	Colmar	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	NA
I.A.2.6(3)	Revise 10 CFR 55	Colmar	NRR/DHFS/LQB	I.A.2.2	6	12/31/97	NA
I.A.2.6(4)	Operator Workshops	Colmar	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	NA
I.A.2.6(5)	Develop Inspection Procedures for Training Program	Colmar	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	NA
I.A.2.6(6)	Nuclear Power Fundamentals	Colmar	NRR/DHFS/LQB	DROP	6	12/31/97	NA
I.A.2.7	Accreditation of Training Institutions	Colmar	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	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	6	12/31/97	
I.A.3.2	Operator Licensing Program Changes	Emrit	NRR/DHFS/OLB	NOTE 3(b)	6	12/31/97	NA
I.A.3.3	Requirements for Operator Fitness	Colmar	RES/DRAO/HFSB	NOTE 3(b)	6	12/31/97	NA
I.A.3.4	Licensing of Additional Operations Personnel	Thatcher	NRR/DHFS/LQB	NOTE 3(b)	6	12/31/97	NA
I.A.3.5	Establish Statement of Understanding with INPO and DOE	Thatcher	NRR/DHFS/HFEB	LI (NOTE 3)	6	12/31/97	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)	6	12/31/97	NA
I.A.4.1(2)	Interim Changes in Training Simulators	Thatcher	NRR/DHFS/OLB	NOTE 3(a)	6	12/31/97	

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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)	6	12/31/97	
I.A.4.2(2)	Upgrade Training Simulator Standards	Colmar	RES/DFO/HFBR	NOTE 3(a)	6	12/31/97	
I.A.4.2(3)	Regulatory Guide on Training Simulators	Colmar	RES/DFO/HFBR	NOTE 3(a)	6	12/31/97	
I.A.4.2(4)	Review Simulators for Conformance to Criteria	Colmar	NRR/DLPQ/LOLB	NOTE 3(a)	6	12/31/97	
I.A.4.3	Feasibility Study of Procurement of NRC Training Simulator	Colmar	RES/DAE/RSRB	LI (NOTE 3)	6	12/31/97	NA
I.A.4.4	Feasibility Study of NRC Engineering Computer	Colmar	RES/DAE/RSRB	LI (NOTE 3)	6	12/31/97	NA
<u>I.B.</u>	<u>SUPPORT PERSONNEL</u>						
<u>I.B.1</u>	<u>Management for Operations</u>						
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)	4	12/31/97	NA
I.B.1.1(2)	Prepare Commission Paper	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	4	12/31/97	NA
I.B.1.1(3)	Issue Requirements for the Upgrading of Management and Technical Resources	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	4	12/31/97	NA
I.B.1.1(4)	Review Responses to Determine Acceptability	Colmar	NRR/DHFT/HFIB	NOTE 3(b)	4	12/31/97	NA
I.B.1.1(5)	Review Implementation of the Upgrading Activities	Colmar	OIE/DQASIP/ORPB	NOTE 3(b)	4	12/31/97	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	4	12/31/97	NA
I.B.1.1(7)	Issue Regulatory Guides 1.33 and 1.8	Colmar	NRR/DHFS/LQB	I.A.2.6(1), 75	4	12/31/97	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)	4	12/31/97	NA
I.B.1.2(2)	Review Near-Term Operating License Facilities	-	NRR/DHFS/LQB	NOTE 3(b)	4	12/31/97	NA
I.B.1.2(3)	Include Findings in the SER for Each Near-Term Operating License Facility	-	NRR/DL/ORAB	NOTE 3(b)	4	12/13/97	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)	4	12/31/97	NA
I.B.1.3(2)	Use Existing Enforcement Options to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	4	12/31/97	NA
I.B.1.3(3)	Use Non-Fiscal Approaches to Accomplish Safest Shutdown Cooling	Sege	RES	LI (NOTE 3)	4	12/31/97	NA
<u>I.B.2</u>	<u>Inspection of Operating Reactors</u>						
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)	1	12/31/97	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
I.B.2.1(2)	Verify that Systems Required to Be Operable Are Properly Aligned	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)	1	12/31/97	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)	1	12/31/97	NA
I.B.2.1(4)	Observe Surveillance Tests to Determine Whether Test Instruments Are Properly Calibrated	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)	1	12/31/97	NA
I.B.2.1(5)	Verify that Licensees Are Complying with Technical Specifications	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)	1	12/31/97	NA
I.B.2.1(6)	Observe Routine Maintenance	Sege	OIE/DQASIP/RCPB	LI (NOTE 3)	1	12/31/97	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)	1	12/31/97	NA
I.B.2.2	Resident Inspector at Operating Reactors	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)	1	12/31/97	NA
I.B.2.3	Regional Evaluations	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)	1	12/31/97	NA
I.B.2.4	Overview of Licensee Performance	Sege	OIE/DQASIP/ORPB	LI (NOTE 3)	1	12/31/97	NA
I.C	OPERATING PROCEDURES						
I.C.1	Short-Term Accident Analysis and Procedures Revision	-	-	-			
I.C.1(1)	Small Break LOCAs	-	NRR	I	4	12/31/97	
I.C.1(2)	Inadequate Core Cooling	-	NRR	I	4	12/31/97	F-04
I.C.1(3)	Transients and Accidents	-	NRR	I	4	12/31/97	F-05
I.C.1(4)	Confirmatory Analyses of Selected Transients	Riggs	NRR/DSI/RSB	NOTE 3(b)	4	12/31/97	NA
I.C.2	Shift and Relief Turnover Procedures	-	NRR	I	4	12/31/97	
I.C.3	Shift Supervisor Responsibilities	-	NRR	I	4	12/31/97	
I.C.4	Control Room Access	-	NRR	I	4	12/31/97	
I.C.5	Procedures for Feedback of Operating Experience to Plant Staff	-	NRR/DL	I	4	12/31/97	F-06
I.C.6	Procedures for Verification of Correct Performance of Operating Activities	-	NRR/DL	I	4	12/31/97	F-07
I.C.7	NSSS Vendor Review of Procedures	-	NRR/DHFS/PSRB	I	4	12/31/97	
I.C.8	Pilot Monitoring of Selected Emergency Procedures for Near-Term Operating License Applicants	-	NRR/DHFS/PSRB	I	4	12/31/97	
I.C.9	Long-Term Program Plan for Upgrading of Procedures	Riggs	NRR/DHFS/PSRB	NOTE 3(b)	4	12/31/97	NA
I.D	CONTROL ROOM DESIGN						
I.D.1	Control Room Design Reviews	-	NRR/DL	I	8	12/31/97	F-08
I.D.2	Plant Safety Parameter Display Console	-	NRR/DL	I	8	12/31/97	F-09
I.D.3	Safety System Status Monitoring	Thatcher	RES/DE/MEB	NOTE 3(b)	8	12/31/97	NA
I.D.4	Control Room Design Standard	Thatcher	RES/DRPS/RHFB	NOTE 3(b)	8	12/31/97	NA
I.D.5	Improved Control Room Instrumentation Research	-	-	-			

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
I.D.5(1)	Operator-Process Communication	Thatcher	RES/DFO/HFBR	NOTE 3(b)	8	12/31/97	NA
I.D.5(2)	Plant Status and Post-Accident Monitoring	Thatcher	RES/DFO/HFBR	NOTE 3(a)	8	12/31/97	
I.D.5(3)	On-Line Reactor Surveillance System	Thatcher	RES/DE/MEB	NOTE 3(b)	8	12/31/97	NA
I.D.5(4)	Process Monitoring Instrumentation	Thatcher	RES/DFO/ICBR	NOTE 3(b)	8	12/31/97	NA
I.D.5(5)	Disturbance Analysis Systems	Thatcher	RES/DRPS/RHFB	LI (NOTE 3)	8	12/31/97	NA
I.D.6	Technology Transfer Conference	Thatcher	RES/DFO/HFBR	LI (NOTE 3)	8	12/31/97	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)	3	12/31/97	NA
I.E.2	Program Office Operational Data Evaluation	Matthews	NRR/DL/ORAB	LI (NOTE 3)	3	12/31/97	NA
I.E.3	Operational Safety Data Analysis	Matthews	RES/DRA/RRBR	LI (NOTE 3)	3	12/31/97	NA
I.E.4	Coordination of Licensee, Industry, and Regulatory Programs	Matthews	AEOD/PTB	LI (NOTE 3)	3	12/31/97	NA
I.E.5	Nuclear Plant Reliability Data System	Matthews	AEOD/PTB	LI (NOTE 3)	3	12/31/97	NA
I.E.6	Reporting Requirements	Matthews	AEOD/PTB	LI (NOTE 3)	3	12/31/97	NA
I.E.7	Foreign Sources	Matthews	IP	LI (NOTE 3)	3	12/31/97	NA
I.E.8	Human Error Rate Analysis	Matthews	RES/DFO/HFBR	LI (NOTE 3)	3	12/31/97	NA
I.F	QUALITY ASSURANCE						
I.F.1	Expand QA List	Pittman	RES/DRA/ARGIB	NOTE 3(b)	4	12/31/98	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	4	12/31/98	NA
I.F.2(2)	Include QA Personnel in Review and Approval of Plant Procedures	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	4	12/31/98	NA
I.F.2(3)	Include QA Personnel in All Design, Construction, Installation, Testing, and Operation Activities	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	4	12/31/98	NA
I.F.2(4)	Establish Criteria for Determining QA Requirements for Specific Classes of Equipment	Pittman	OIE/DQASIP/QUAB	LOW	4	12/31/98	NA
I.F.2(5)	Establish Qualification Requirements for QA and QC Personnel	Pittman	OIE/DQASIP/QUAB	LOW	4	12/31/98	NA
I.F.2(6)	Increase the Size of Licensees' QA Staff	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	4	12/31/98	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	4	12/31/98	NA
I.F.2(8)	Compare NRC QA Requirements with Those of Other Agencies	Pittman	OIE/DQASIP/QUAB	LOW	4	12/31/98	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
I.F.2(9)	Clarify Organizational Reporting Levels for the QA Organization	Pittman	OIE/DQASIP/QUAB	NOTE 3(a)	4	12/31/98	NA
I.F.2(10)	Clarify Requirements for Maintenance of "As-Built" Documentation	Pittman	OIE/DQASIP/QUAB	LOW	4	12/30/98	NA
I.F.2(11)	Define Role of QA in Design and Analysis Activities	Pittman	OIE/DQASIP/QUAB	LOW	4	12/30/98	NA
<u>I.G</u>	<u>PREOPERATIONAL AND LOW-POWER TESTING</u>						
I.G.1	Training Requirements	-	NRR/DHFS/PSRB	I	3	12/31/97	
I.G.2	Scope of Test Program	Vandermolen	NRR/DHFS/PSRB	NOTE 3(a)	3	12/31/97	NA
<u>II.A</u>	<u>SITING</u>						
II.A.1	Siting Policy Reformulation	Vandermolen	NRR/DE/SAB	NOTE 3(b)	2	12/31/97	NA
II.A.2	Site Evaluation of Existing Facilities	Vandermolen	NRR/DE/SAB	V.A.1	2	12/31/97	NA
<u>II.B</u>	<u>CONSIDERATION OF DEGRADED OR MELTED CORES IN SAFETY REVIEW</u>						
II.B.1	Reactor Coolant System Vents	-	NRR/DL	I	4	12/31/97	F-10
II.B.2	Plant Shielding to Provide Access to Vital Areas and Protect Safety Equipment for Post-Accident Operation	-	NRR/DL	I	4	12/31/97	F-11
II.B.3	Post-Accident Sampling	-	NRR/DL	I	4	12/31/97	F-12
II.B.4	Training for Mitigating Core Damage	-	NRR/DL	I	4	12/31/97	F-13
II.B.5	Research on Phenomena Associated with Core Degradation and Fuel Melting	-	-	-			
II.B.5(1)	Behavior of Severely Damaged Fuel	Vandermolen	RES/DSR/AEB	LI (NOTE 5)	4	12/31/97	NA
II.B.5(2)	Behavior of Core-Melt	Vandermolen	RES/DSR/AEB	LI (NOTE 5)	4	12/31/97	NA
II.B.5(3)	Effect of Hydrogen Burning and Explosions on Containment Structure	Vandermolen	RES/DSR/AEB	LI (NOTE 5)	4	12/31/97	NA
II.B.6	Risk Reduction for Operating Reactors at Sites with High Population Densities	Pittman	NRR/DST/RRAB	NOTE 3(a)	4	12/31/97	
II.B.7	Analysis of Hydrogen Control	Matthews	NRR/DSI/CSB	II.B.8	4	12/31/97	
II.B.8	Rulemaking Proceeding on Degraded Core Accidents	Vandermolen	RES/DRAO/RAMR	NOTE 3(a)	4	12/31/97	
<u>II.C</u>	<u>RELIABILITY ENGINEERING AND RISK ASSESSMENT</u>						
II.C.1	Interim Reliability Evaluation Program	Pittman	RES/DRAO/RRB	NOTE 3(b)	3	12/31/97	NA
II.C.2	Continuation of Interim Reliability Evaluation Program	Pittman	NRR/DST/RRAB	NOTE 3(b)	3	12/31/97	NA
II.C.3	Systems Interaction	Pittman	NRR/DST/GIB	A-17	3	12/31/97	NA
II.C.4	Reliability Engineering	Pittman	RES/DRPS/RHFB	NOTE 3(b)	3	12/31/97	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
II.D	REACTOR COOLANT SYSTEM RELIEF AND SAFETY VALVES						
II.D.1	Testing Requirements	-	NRR/DL	I	3	12/31/98	F-14
II.D.2	Research on Relief and Safety Valve Test Requirements	Riggs	RES	LOW	3	12/31/98	NA
II.D.3	Relief and Safety Valve Position Indication	-	NRR	I	3	12/31/98	
II.E	SYSTEM DESIGN						
II.E.1	Auxiliary Feedwater System						
II.E.1.1	Auxiliary Feedwater System Evaluation	-	NRR/DL	I	2	12/31/97	F-15
II.E.1.2	Auxiliary Feedwater System Automatic Initiation and Flow Indication	-	NRR/DL	I	2	12/31/97	F-16, F-17
II.E.1.3	Update Standard Review Plan and Develop Regulatory Guide	Riggs	RES/DRA/RRBR	NOTE 3(a)	2	12/31/97	
II.E.2	Emergency Core Cooling System						
II.E.2.1	Reliance on ECCS	Riggs	NRR/DSI/RSB	II.K.3(17)	3	12/31/98	NA
II.E.2.2	Research on Small Break LOCAs and Anomalous Transients	Riggs	RES/DAE/RSRB	NOTE 3(b)	3	12/31/98	NA
II.E.2.3	Uncertainties in Performance Predictions	Vandermolen	NRR/DSI/RSB	LOW	3	12/31/98	NA
II.E.3	Decay Heat Removal						
II.E.3.1	Reliability of Power Supplies for Natural Circulation	-	NRR/DL	I	2	12/31/97	
II.E.3.2	Systems Reliability	Vandermolen	NRR/DST/GIB	A-45	2	12/31/97	NA
II.E.3.3	Coordinated Study of Shutdown Heat Removal Requirements	Vandermolen	NRR/DST/GIB	A-45	2	12/31/97	NA
II.E.3.4	Alternate Concepts Research	Riggs	RES/DAE/FBRB	NOTE 3(b)	2	12/31/97	NA
II.E.3.5	Regulatory Guide	Riggs	NRR/DST/GIB	A-45	2	12/31/97	NA
II.E.4	Containment Design						
II.E.4.1	Dedicated Penetrations	-	NRR/DL	I	2	12/31/97	F-18
II.E.4.2	Isolation Dependability	-	NRR/DL	I	2	12/31/97	F-19
II.E.4.3	Integrity Check	Milstead	RES/DRPS/RPSI	NOTE 3(b)	2	12/31/97	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)	2	12/31/97	
II.E.4.4(2)	Issue Letter to Licensees Requesting Information on Isolation Letter	Milstead	NRR/DSI/CSB	NOTE 3(a)	2	12/31/97	
II.E.4.4(3)	Issue Letter to Licensees on Valve Operability	Milstead	NRR/DSI/CSB	NOTE 3(a)	2	12/31/97	
II.E.4.4(4)	Evaluate Purging and Venting During Normal Operation	Milstead	NRR/DSI/CSB	NOTE 3(b)	2	12/31/97	NA
II.E.4.4(5)	Issue Modified Purging and Venting Requirement	Milstead	NRR/DSI/CSB	NOTE 3(b)	2	12/31/97	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
II.E.5	Design Sensitivity of B&W Reactors						
II.E.5.1	Design Evaluation	Thatcher	NRR/DSI/RSB	NOTE 3(a)	2	12/31/98	
II.E.5.2	B&W Reactor Transient Response Task Force	Thatcher	NRR/DL/ORAB	NOTE 3(a)	2	12/31/98	
II.E.6	In Situ Testing of Valves						
II.E.6.1	Test Adequacy Study	Thatcher	RES/DE/EIB	NOTE 3(a)	2	12/31/98	
II.F	INSTRUMENTATION AND CONTROLS						
II.F.1	Additional Accident Monitoring Instrumentation	-	NRR/DL	I	3	12/31/98	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	3	12/31/98	F-26
II.F.3	Instruments for Monitoring Accident Conditions	Vandermolen	RES/DFO/ICBR	NOTE 3(a)	3	12/31/98	
II.F.4	Study of Control and Protective Action Design Requirements	Thatcher	NRR/DSI/ICSB	DROP	3	12/31/98	NA
II.F.5	Classification of Instrumentation, Control, and Electrical Equipment	Thatcher	RES/DE	LI (NOTE 3)	3	12/31/98	NA
II.G	ELECTRICAL POWER						
II.G.1	Power Supplies for Pressurizer Relief Valves, Block Valves, and Level Indicators	-	NRR	I	1	12/31/98	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)	3	12/31/98	NA
II.H.2	Obtain Technical Data on the Conditions Inside the TMI-2 Containment Structure	Milstead	RES/DRAA/AEB	NOTE 3(b)	3	12/31/98	NA
II.H.3	Evaluate and Feed Back Information Obtained from TMI	Milstead	NRR/TMIPO	II.H.2	3	12/31/98	NA
II.H.4	Determine Impact of TMI on Socioeconomic and Real Property Values	Milstead	RES/DHSWM/SEBR	LI (NOTE 3)	3	12/31/98	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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)	1	12/31/98	NA
II.J.1.2	Modify Existing Vendor Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)	1	12/31/98	NA
II.J.1.3	Increase Regulatory Control Over Present Non-Licensees	Riani	OIE/DQASIP	LI (NOTE 3)	1	12/31/98	NA
II.J.1.4	Assign Resident Inspectors to Reactor Vendors and Architect-Engineers	Riani	OIE/DQASIP	LI (NOTE 3)	1	12/31/98	NA
II.J.2	Construction Inspection Program						
II.J.2.1	Reorient Construction Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)	1	12/31/98	NA
II.J.2.2	Increase Emphasis on Independent Measurement in Construction Inspection Program	Riani	OIE/DQASIP	LI (NOTE 3)	1	12/31/98	NA
II.J.2.3	Assign Resident Inspectors to All Construction Sites	Riani	OIE/DQASIP	LI (NOTE 3)	1	12/31/98	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	1	12/31/98	NA
II.J.3.2	Issue Regulatory Guide	Pittman	NRR/DHFS/LQB	I.B.1.1	1	12/31/98	NA
II.J.4	Revise Deficiency Reporting Requirements						
II.J.4.1	Revise Deficiency Reporting Requirements	Riani	AEOD/DSP/ROAB	NOTE 3(a)	3	12/31/98	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	-

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	-
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	-

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	-
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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 Rev.	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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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
<u>III.D.2</u>	<u>Public Radiation Protection Improvement</u>						
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	3	12/31/98	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	3	12/31/98	NA
III.D.2.1(3)	Revise Regulatory Guides	Emrit	NRR/DSI/METB	LOW	3	12/31/98	NA
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)	3	12/31/98	NA
III.D.2.2(2)	Evaluate Data Collected at Quad Cities	Emrit	NRR/DSI/RAB	III.D.2.5	3	12/31/98	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	3	12/31/98	NA
III.D.2.2(4)	Revise SRP and Regulatory Guides	Emrit	NRR/DSI/RAB	III.D.2.5	3	12/31/98	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)	3	12/31/98	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)	3	12/31/98	NA
III.D.2.3(3)	Establish Feasible Method of Pathway Interdiction	Emrit	NRR/DE/EHEB	NOTE 3(b)	3	12/31/98	NA
III.D.2.3(4)	Prepare a Summary Assessment	Emrit	NRR/DE/EHEB	NOTE 3(b)	3	12/31/98	NA
III.D.2.4	Offsite Dose Measurements	-	-	-			
III.D.2.4(1)	Study Feasibility of Environmental Monitors	Vandermolen	NRR/DSI/RAB	NOTE 3(b)	3	12/31/98	NA
III.D.2.4(2)	Place 50 TLDs Around Each Site	Vandermolen	OIE/DRP/ORPB	LI (NOTE 3)	3	12/31/98	NA
III.D.2.5	Offsite Dose Calculation Manual	Vandermolen	NRR/DSI/RAB	NOTE 3(b)	3	12/31/98	NA
III.D.2.6	Independent Radiological Measurements	Vandermolen	OIE/DRP/ORPB	LI (NOTE 3)	3	12/31/98	NA
<u>III.D.3</u>	<u>Worker Radiation Protection Improvement</u>						
III.D.3.1	Radiation Protection Plans	Vandermolen	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	Vandermolen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA
III.D.3.2(2)	Issue a Regulatory Guide	Vandermolen	RES/DFO/ORPBR	LI (NOTE 3)	3	12/31/87	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
III.D.3.2(3)	Develop Standard Performance Criteria	Vandermolen	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	Vandermolen	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	12/31/86	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	2	12/31/86	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	Vandermolen	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	Vandermolen	DFO/ORPBR	LI (NOTE 3)	2	12/31/86	NA
III.D.3.5(3)	Revise 10 CFR 20	Vandermolen	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
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	
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	B-17, B-22
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	Vandermolen	NRR/DSI/CSB	DROP	1	12/31/98	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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	B-23
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	DROP	3	06/30/00	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	
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)	2	06/30/00	
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	Vandermolen	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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
B-17	Criteria for Safety-Related Operator Actions	Milstead	RES/DST/CIHFB	NOTE 3(b)	3	06/30/00	
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
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	

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	Vandermolen	NRR/DE/EMEB	NOTE 3(b)	1	06/30/00	
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	NOTE 3(b)	1	06/30/00	
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-45
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
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	DROP	1	12/31/98	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

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	Vandermolen	NRR/DSI/CPB	NOTE 3(b)	1	12/31/94	NA
7.	Failures Due to Flow-Induced Vibrations	Vandermolen	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
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	NOTE 3(b)	3	06/30/96	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	Vandermolen	NRR/DSI/RSB	NOTE 3(b)	2	12/31/94	NA
23.	Reactor Coolant Pump Seal Failures	Riggs	RES/DET/GSIB	NOTE 3(b)	1	06/30/00	NA
24.	Automatic ECCS Switchover to Recirculation	Milstead	RES/DET/GSIB	NOTE 3(b)	3	12/31/95	NA
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	Vandermolen	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	Vandermolen	NRR/DSI/CPB, RSB	DROP	2	12/31/98	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
41.	BWR Scram Discharge Volume Systems	Vandermolen	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	B-107

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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	L-913
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	Vandermolen	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	Vandermolen	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	-	-	-			

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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
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	DROP	2	12/31/98	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,

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
75.	(Cont.)						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	NOTE 3(b)	3	12/31/97	
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	Vandermolen	NRR/DSI/RSB, ASB, CPB	DROP	2	12/31/98	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	Vandermolen	RES/DRPS/RPSI	NOTE 3(b)	1	06/30/89	NA
83.	Control Room Habitability	Emrit	RES/DST/AEB	NOTE 3(b)	2	06/30/96	NA
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	Vandermolen	NRR/DSI/RSB, ICSB	DROP	2	12/31/98	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	Vandermolen	NRR/DSI/RSB, CPB	DROP	1	12/31/98	NA
93.	Steam Binding of Auxiliary Feedwater Pumps	Pittman	RES/DRPS/RPSI	NOTE 3(a)		06/30/88	B-98
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	Vandermolen	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	L-817

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
100.	Once-Through Steam Generator Level	Jackson	RES/DSIR/EIB	DROP	1	06/30/95	NA
101.	BWR Water Level Redundancy	Vandermolen	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	DROP	3	06/30/00	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)	2	06/30/00	NA
116.	Accident Management	Pittman	RES/DRA/ARGIB	S		06/30/91	NA
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)	3	12/31/97	NA
119.2	Piping Damping Values	Riggs	NRR/DE	RI (DROP)	3	12/31/97	NA
119.3	Decoupling the OBE from the SSE	Riggs	NRR/DE	RI (S)	3	12/31/97	NA
119.4	BWR Piping Materials	Riggs	NRR/DE	RI (NOTE 5)	3	12/31/97	NA
119.5	Leak Detection Requirements	Riggs	NRR/DE	RI (NOTE 5)	3	12/31/97	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	Vandermolen	NRR/DSRO/RSIB	124	4	12/31/98	NA
122.1.b	Recovery of Auxiliary Feedwater	Vandermolen	NRR/DSRO/RSIB	124	4	12/31/98	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
122.1.c.	Interruption of Auxiliary Feedwater Flow	Vandermolen	NRR/DSRO/RSIB	124	4	12/31/98	NA
122.2	Initiating Feed-and-Bleed	Vandermolen	NRR/DEST/SRXB	NOTE 3(b)	4	12/31/98	NA
122.3	Physical Security System Constraints	Vandermolen	NRR/DSRO/SPEB	DROP	4	12/31/98	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.	<u>Davis-Besse Loss of All Feedwater Event of June 9, 1985: Long-Term Actions</u>	-	-	-			
125.I.1	Availability of the Shift Technical Advisor	Vandermolen	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.I.2	PORV Reliability	-	-	-	7	12/31/98	
125.I.2.a	Need for a Test Program to Establish Reliability of the PORV	Vandermolen	NRR/DSRO/SPEB	70	7	12/31/98	NA
125.I.2.b	Need for PORV Surveillance Tests to Confirm Operational Readiness	Vandermolen	NRR/DSRO/SPEB	70	7	12/31/98	NA
125.I.2.c	Need for Additional Protection Against PORV Failure	Vandermolen	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.I.2.d	Capability of the PORV to Support Feed-and-Bleed	Vandermolen	NRR/DSRO/SPEB	A-45	7	12/31/98	NA
125.I.3	SPDS Availability	Milstead	RES/DRA/ARGIB	NOTE 3(b)	7	12/31/98	NA
125.I.4	Plant-Specific Simulator	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.I.5	Safety Systems Tested in All Conditions Required by DBA	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.I.6	Valve Torque Limit and Bypass Switch Settings	Vandermolen	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.I.7	Operator Training Adequacy	-	-	-			
125.I.7.a	Recover Failed Equipment	Pittman	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.I.7.b	Realistic Hands-On Training	Vandermolen	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.I.8	Procedures and Staffing for Reporting to NRC Emergency Response Center	Vandermolen	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.1	Need for Additional Actions on AFW Systems	-	-	-			
125.II.1.a	Two-Train AFW Unavailability	Vandermolen	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.II.1.b	Review Existing AFW Systems for Single Failure	Vandermolen	NRR/DSRO/SPEB	124	7	12/31/98	NA
125.II.1.c	NUREG-0737 Reliability Improvements	Vandermolen	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.II.1.d	AFW/Steam and Feedwater Rupture Control System/ICS Interactions in B&W Plants	Vandermolen	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.II.2	Adequacy of Existing Maintenance Requirements for Safety-Related Systems	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.3	Review Steam/Feedline Break Mitigation Systems for Single Failure	V'Molen	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.II.4	Thermal Stress of OTSG Components	Riggs	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.II.5	Thermal-Hydraulic Effects of Loss and Restoration of Feedwater on Primary System Components	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
125.II.6	Reexamine PRA Estimates of Core Damage Risk from Loss of All Feedwater	Vandermolen	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.7	Reevaluate Provision to Automatically Isolate Feedwater from Steam Generator During a Line Break	Vandermolen	RES/DRPS/RPSI	NOTE 3(b)	7	12/31/98	NA
125.II.8	Reassess Criteria for Feed-and-Bleed Initiation	Vandermolen	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.9	Enhanced Feed-and-Bleed Capability	Vandermolen	NRR/DSRO/SPEB	DROP	7	12/31/98	NA
125.II.10	Hierarchy of Impromptu Operator Actions	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.11	Recovery of Main Feedwater as Alternative to Auxiliary Feedwater	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.12	Adequacy of Training Regarding PORV Operation	Riggs	RES/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.13	Operator Job Aids	Pittman	NRR/DRA/ARGIB	DROP	7	12/31/98	NA
125.II.14	Remote Operation of Equipment Which Must Now Be Operated Locally	Vandermolen	NRR/DSRO/SPEB	DROP	7	12/31/98	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)	2	12/31/95	
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	1	12/31/95	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	DROP	2	12/31/98	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
142.	Leakage Through Electrical Isolators in Instrumentation Circuits	Milstead	RES/DSIR/EIB	NOTE 3(b)	4	12/31/97	NA
143.	Availability of Chilled Water Systems and Room Cooling	Milstead	RES/DRA/ARGIB	NOTE 3(b)	2	06/30/95	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
144.	Scram Without a Turbine/Generator Trip	Hrabal	RES/DSIR/EIB	DROP	2	12/31/98	NA
145.	Actions to Reduce Common Cause Failures	Rasmuson	RES/DST/PRAB	NOTE 3(b)	3	06/30/00	NA
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 3)	1	06/30/00	NA
149.	Adequacy of Fire Barriers	Emrit	RES/DSIR/EIB	DROP	2	12/31/98	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	DROP	2	12/31/98	NA
153.	Loss of Essential Service Water in LWRs	Riggs	RES/DRA/ARGIB	NOTE 3(b)	2	12/31/95	NA
154.	Adequacy of Emergency and Essential Lighting	Woods	RES/DSIR/SAIB	DROP	2	12/31/98	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	6	06/30/00	NA
156.1.2	Dam Integrity and Site Flooding	Chen	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.1.3	Site Hydrology and Ability to Withstand Floods	Chen	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.1.4	Industrial Hazards	Ferrell	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.1.5	Tornado Missiles	Chen	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.1.6	Turbine Missiles	Emrit	RES/DSIR/EIB	DROP	6	06/30/00	NA
156.2.1	Severe Weather Effects on Structures	Chen	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.2.2	Design Codes, Criteria, and Load Combinations	Kirkwood	RES/DSIR/EIB	DROP	6	06/30/00	NA
156.2.3	Containment Design and Inspection	Shaukat	RES/DSIR/EIB	DROP	6	06/30/00	NA
156.2.4	Seismic Design of Structures, Systems, and Components	Chen	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.3.1.1	Shutdown Systems	Woods	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.3.1.2	Electrical Instrumentation and Controls	Woods	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.3.2	Service and Cooling Water Systems	Su	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.3.3	Ventilation Systems	Burdick	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.3.4	Isolation of High and Low Pressure Systems	Burdick	RES/DSIR/SAIB	DROP	6	06/30/00	NA
156.3.5	Automatic ECCS Switchover	Milstead	RES/DSIR/SAIB	24	6	06/30/00	NA
156.3.6.1	Emergency AC Power	Emrit	RES/DSIR/EIB	DROP	6	06/30/00	NA

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
156.3.6.2	Emergency DC Power	Rourk	RES/DSIR/EIB	DROP	6	06/30/00	NA
156.3.8	Shared Systems	Emrit	RES/DSIR/EIB	DROP	6	06/30/00	NA
156.4.1	RPS and ESFS Isolation	Emrit	RES/DSIR/EIB	142	6	06/30/00	NA
156.4.2	Testing of the RPS and ESFS	Chang	RES/DSIR/SAIB	120	6	06/30/00	NA
156.6.1	Pipe Break Effects on Systems and Components	Page	RES/DET/GSIB	NOTE 4	6	06/30/00	
157.	Containment Performance	Shaperow	RES/DSIR/SAIB	NOTE 3(b)		06/30/95	NA
158.	Performance of Power-Operated Valves Under Design Basis Conditions	Hrabal	RES/DET/GSIB	NOTE 3(b)	2	06/30/00	NA
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	Coffman	RES/DET/GSIB	HIGH		12/31/97	
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	NOTE 3(b)	2	06/30/00	NA
166.	Adequacy of Fatigue Life of Metal Components	Emrit	NRR/DE/EMEB	NOTE 3(b)	2	12/31/97	NA
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	HIGH	2	12/31/98	
169.	BWR MSIV Common Mode Failure Due to Loss of Accumulator Pressure	Emrit	RES/DET/GSIB	DROP	1	06/30/00	NA
170.	Fuel Damage Criteria for High Burnup Fuel	Emrit	RES/DET/GSIB	HIGH	1	12/31/98	
171.	ESF Failure from LOOP Subsequent to a LOCA	Rourk	RES/DET/GSIB	NOTE 3(b)	1	12/31/98	NA
172.	Multiple System Responses Program	Emrit	RES/DET/GSIB	HIGH	1	12/31/98	
173.	Spent Fuel Storage Pool	-	-				
173.A	Operating Facilities	Emrit	RES/DET/GSIB	HIGH	3	06/30/00	
173.B	Permanently Shutdown Facilities	Emrit	RES/DET/GSIB	NOTE 3(b)	3	06/30/00	NA
174.	Fastener Gaging Practices	-	-				
174.A	SONGS Employees' Concern	Emrit	RES/DET/GSIB	NOTE 3(b)	1	06/30/00	NA
174.B	Johnson Gage Company Concern	Emrit	RES/DET/GSIB	NOTE 3(b)	1	06/30/00	NA
175.	Nuclear Power Plant Shift Staffing	Emrit	RES/DET/GSIB	NOTE 3(b)	1	06/30/00	NA
176.	Loss of Fill-Oil in Rosemount Transmitters	Emrit	RES/DET/GSIB	NOTE 3(b)	1	06/30/00	NA
177.	Vehicle Intrusion at TMI	Emrit	RES/DET/GSIB	NOTE 3(a)	1	06/30/00	NA
178.	Effect of Hurricane Andrew on Turkey Point	Emrit	RES/DET/GSIB	LI (NOTE 3)	2	06/30/00	
179.	Core Performance	Emrit	RES/DET/GSIB	LI (NOTE 5)	1	06/30/00	
180.	Notice of Enforcement Discretion	Emrit	RES/DET/GSIB	LI (NOTE 3)	1	06/30/00	
181.	Fire Protection	Emrit	RES/DET/GSIB	LI (NOTE 5)	1	06/30/00	

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Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
182.	General Electric Extended Power Uprate	Emrit	RES/DET/GSIB	RI (NOTE 5)	1	06/30/00	
183.	Cycle-Specific Parameter Limits in Technical Specifications	Emrit	RES/DET/GSIB	RI (NOTE 3)	2	06/30/00	
184.	Endangered Species	Emrit	RES/DET/GSIB	EI (NOTE 5)	1	06/30/00	
185.	Control of Recriticality Following Small-Break LOCA In PWRs	Vandermolen	RES/DSARE/REAHFB	NOTE 4			
186.	Potential Risk and Consequences of Heavy Load Drops	Lloyd	RES/DSARE/REAHFB	NOTE 4			
187.	The Potential Impact of Postulated Cesium Concentration on Equipment Qualification in the Containment Sump in Nuclear Power Plants	Vandermolen	RES/DSARE/REAHFB	NOTE 4			
190.	Fatigue Evaluation of Metal Components for 60-Year Plant Life	Shaukat	RES/DET/GSIB	NOTE 3(b)	2	06/30/00	NA
191.	Assessment of Debris Accumulation on PWR Sump Performance	Marshall	RES/DET/GSIB	HIGH	1	12/31/98	
	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
HF4	PROCEDURES						
HF4.1	Inspection Procedure for Upgraded Emergency Operating Procedures	Pittman	NRR/DLPQ/LHFB	NOTE 3(b)	6	06/30/95	NA

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
CH1.3	Bypassing Safety Systems	-	-				
CH1.3A	Revise Regulatory Guide 1.47	Emrit	RES/DE/EMEB	LI (NOTE 5)		06/30/89	NA
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
<u>CH2</u>	<u>DESIGN</u>						
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
<u>CH3</u>	<u>CONTAINMENT</u>						
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
<u>CH4</u>	<u>EMERGENCY PLANNING</u>						
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

Table II (Continued)

Action Plan Item/ Issue No.	Title	Priority Engineer	Lead Office/ Division/ Branch	Safety Priority Ranking	Latest Rev.	Latest Issuance Date	MPA No.
<u>CH5</u>	<u>SEVERE ACCIDENT PHENOMENA</u>						
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
<u>CH6</u>	<u>GRAPHITE-MODERATED REACTORS</u>						
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	S	RESOLVED STAGES NOTE 1	RESOLVED STAGES NOTE 2	RESOLVED STAGES NOTE 3	USI	HIGH	MEDIUM	LOW	DROP	NOTE 4	NOTE 5	TOTAL
TMI ACTION PLAN ITEM (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	36	-	0	0	0	14	0	-	70
RI	-	-	-	-	6	-	-	-	-	-	-	1	7
LI	-	-	-	-	11	-	-	-	-	-	-	12	23
EI	-	-	-	-	13	-	-	-	-	-	-	2	15
NEW GENERIC ISSUES (266)													
GSI	-	54	0	0	79	0	7	0	4	96	3	-	243
RI	-	1	-	-	5	-	-	-	-	1	-	5	12
LI	-	1	-	-	8	-	-	-	-	-	-	4	13
EI	-	-	-	-	-	-	-	-	-	-	-	1	1
HUMAN FACTORS ISSUES (27)													
GSI	-	8	0	0	8	0	0	0	0	0	-	-	16
LI	-	-	-	-	3	-	-	-	-	-	-	8	11
CHERNOBYL ISSUES (32)													
LI	-	2	-	-	7	-	-	-	-	-	-	23	32
TOTAL:	84	132	0	0	413	0	7	0	16	120	3	64	839

ITEM A-38: TORNADO MISSILES

DESCRIPTION

Historical Background

The AEC first established missile-protection requirements in 1967. GDC-2 and GDC-4 of 10 CFR Part 50, Appendix A, require in part that structures, systems, and components important to safety be designed to be able to withstand the effects of tornado missiles. Specific design acceptance criteria to meet the requirements of GDC-2 and GDC-4 and recommended methods of satisfying the acceptance criteria are detailed in SRP[11] Sections 3.3.2 and 3.5.1.4 and in Regulatory Guides 1.76[42] and 1.117.[43]

A limited reexamination of tornado missile protection requirements in 1976 resulted in significant reduction in requirements. However, it was suggested[2] that the existing tornado missile protection requirements may have been more conservative than necessary. The purpose of this NUREG-0371[2] item was to reexamine the requirements more precisely with a view to a possible outcome of adequate protection at less industry cost. The evaluation of this issue included consideration of Issue A-32.

Safety Significance

Missiles generated by tornadoes could potentially damage systems or components containing radioactivity or necessary for the safe shutdown of a reactor.[41] This damage may directly result in the release of radioactivity to the environment or ultimately affect core cooling and result in core damage or melting.

Possible Solution

The existing tornado missile requirements included structural strengthening of potential safety-significant targets of tornado missiles, concrete missile protection for spent fuel pools, and increased concrete wall thickness around safety-class structures other than containment to stop tornado missiles.

The suggested task was to investigate whether postulated missile velocities, size, and orientation used in plant safety analyses were more conservative than tornado damage histories warranted. The end product of this task was to be a set of design basis missiles that did not impose unnecessary design requirements on plant construction and for which a sound technical basis existed.

PRIORITY DETERMINATION

Frequency Estimate

This issue was addressed in WASH-1400[16] where the findings presented were based on work by Doan.[41] It was stated that the probability of energetic tornado-generated missiles would be less than 5×10^{-6} and that the only likely damage to sensitive plant systems would be the loss of the diesel generator building doors. The probability of this event causing a core-melt accident or any other significant radioactive release would be less than 10^{-3}.

Thus, the frequency of a core-melt accident resulting from a tornado was estimated to be 5×10^{-9} /RY or 1.5×10^{-7}/reactor over a 30-year operating life. Large changes to the missile criteria would not be made and the effect on core-melt frequency would be intentionally small (~10%). A 10% increase in the core-melt frequency would be 1.5×10^{-8}/reactor.

Consequence Estimate

Depending on the systems or structures that are damaged, almost any type of core-melt scenario could occur. However, as a bounding estimate, it was assumed that the worst core-melt scenarios (Release Categories PWR-1, PWR-2, PWR-3, BWR-1, and BWR-2) would occur. Although a tornado missile event is likely to be followed by high winds, typical meteorological behavior was assumed along with a mean population density of 340 people per square-mile. The release categories listed above were calculated to result in between 4 and 7 million man-rem. Therefore, the release from a tornado missile event was estimated to result in about 5×10^6 man-rem.

Assuming possible reduced (lower-cost) tornado missile protection requirements, the total increase in risk for future reactors was estimated to be $(1.5 \times 10^{-8})(5 \times 10^6)$ man-rem/reactor or 0.08 man-rem/reactor.

Cost Estimate

Industry Cost: The potential cost savings to future plants was estimated, to a rough approximation, by considering the volume of reinforced concrete potentially saved. According to an estimate from SEB/DE/NRR, tornado protection (for wind loads and missiles combined - they are not readily separable) involved roughly 2,200 cubic-yards of reinforced concrete for a typical plant. At $900/cubic-yard of concrete in place (based on Means, "Building Construction Cost Data, 1981," for elevated slabs, plus 15% inflation since January 1981 and 100% for NRC special requirements), the estimated cost was about $2M/plant. Since only modest changes to the criteria were intended, the reduction in missile resistance reflected in design parameters, such as wall thickness, would be small (again ~10%). A 10% saving due to reduced missile requirements would mean $200,000 saved per future plant.

NRC Cost: The proposed NRC study was estimated to cost about $300,000, based on the NUREG-0371[2] estimate of 2.4 man-years plus a $60,000 technical assistance contract. However, when amortized over more than 10 future plants, the NRC cost was small compared to industry costs.

Total Cost: The total industry and NRC cost associated with a possible solution to the issue was estimated to be $0.2M/reactor

Value/Impact Assessment

The estimated value/impact score for retention of the existing tornado missile protection requirements for future plants (rather than relaxing them as discussed) was given as follows:

$$S = \frac{0.08 \text{ man-rem/reactor}}{\$0.2\text{M/reactor}}$$

$$= 0.4 \text{ man-rem/\$M}$$

Uncertainties

At the time this issue was evaluated, tornado missile protection was a recent development nearly unique to nuclear power plants and was not a matter of any long-established engineering practice. The probabilistic estimates were widely recognized as subject to great data-base uncertainties (See NUREG/CR-2300,[187] p.10-1). Existing and possible modified future requirements depended heavily on engineering judgment and intuitive interpretation of limited data. However, even if the estimated frequency of a core-melt accident resulting from a tornado (which was very small) was increased by a factor of 10 or even 100, the conclusion would not change.

The magnitude of the cost savings (if any) that could be achieved, depending on the outcome of the proposed study, could not be reliably predicted at the time this issue was evaluated. At best, these savings could be bounded by consideration of the total cost of tornado protection. The total savings achievable would be a function of the number of future plants affected and the distribution of these plants among the three regions of the U.S. with a high incidence of tornadoes. If the cost savings were significantly smaller, the net cost savings including NRC costs would become negligible.

Other Considerations

Reduction of tornado missile protection requirements may not be fully reflected in reduced concrete wall thicknesses, etc., because, at some point, other factors such as tornado wind loadings may become controlling. Also involved here were various man-made external events for which specific consideration had not been required, because of reliance on tornado missile protection to provide an adequate "umbrella" of protection. These events include small aircraft crashes, missiles from offsite explosions, and physical attacks.

CONCLUSION

It was possible that further reexamination of tornado missile requirements could have led to industry cost savings due to reduction of these requirements (beyond the reductions made on the basis of the 1976 reexamination) without significant risk increase. If there was greater assurance that these cost savings would be significant and likely to be achieved (by performing a more detailed design and cost analysis), this issue would have warranted a high priority. However, the savings could only be realized in those plants not yet designed or under construction. Since such new plants were possible at some indefinite future time, the issue was given a low priority ranking (see Appendix C) in November 1983. 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. Further prioritization, using the conversion factor of $2,000/man-rem approved[1689] by the Commission in September 1995, resulted in an impact/value ratio (R) of $2.5M/man-rem, which placed the issue in the DROP category.

REFERENCES

2. NUREG-0371, "Task Action Plans for Generic Activities (Category A)," U.S. Nuclear Regulatory Commission, November 1978.

16. WASH-1400 (NUREG-75/014), "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," U.S. Atomic Energy Commission, October 1975.

41. Nuclear Safety, Volume 11, No. 4, pp. 296-308, "Tornado Considerations for Nuclear Power Plant Structures Including the Spent Fuel Storage Pool," P. L. Doan, July 1970.

42. Regulatory Guide 1.76, "Design Basis Tornado for Nuclear Power Plants," U.S. Nuclear Regulatory Commission, April 1974.

43. Regulatory Guide 1.117, "Tornado Design Classification," U.S. Nuclear Regulatory Commission, June 1976, (Rev. 1) April 1978.

187. NUREG/CR-2300, "PRA Procedures Guide," U.S. Nuclear Regulatory Commission, (Vols. 1 and 2) January 1983.

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

1689. Memorandum to J. Taylor from J. Hoyle, "COMSECY-95-033 - Proposed Dollar per Person-Rem Conversion Factor; Response to SRM Concerning Issuance of Regulatory Analysis Guidelines of the U.S. Nuclear Regulatory Commission and SRM Concerning the Need for a Backfit Rule for Materials Licensees (RES-950225) (WITS-9100294)," September 18, 1995.

ITEM A-46: SEISMIC QUALIFICATION OF EQUIPMENT IN OPERATING PLANTS

DESCRIPTION

The design criteria and methods for the seismic qualification of mechanical and electrical equipment in nuclear power plants underwent significant changes during the course of the licensing of commercial nuclear power plants. Consequently, it was believed that the margins of safety provided in equipment to resist seismically-induced loads and to perform their intended safety functions could vary considerably. Therefore, to ensure the ability of plants to achieve a safe shutdown condition when subject to a seismic event, the seismic qualification of equipment in operating plants had to be reassessed.

The objective of this issue was to establish an explicit set of guidelines that could be used to judge the adequacy of the seismic qualification of mechanical and electrical equipment at all operating plants, in lieu of attempting to backfit existing design criteria to new plants. This guidance was to address equipment required to safely shut down a plant as well as equipment whose function is not required for safe shutdown but whose failure could result in adverse conditions that might impair shutdown functions. Also, explicit guidelines were to be established for use in requalifying equipment whose qualification was found to be inadequate. The issue was declared a USI in February 1981 and published in NUREG-0705.[44] A detailed action plan for resolving the issue was published in NUREG-0649,[1061] Revision 1.

CONCLUSION

Resolution of the issue was based mainly on work completed by the Seismic Qualification Utility Group (SQUG) and EPRI using the seismic and test experience data approach[1751] that was reviewed and endorsed by the Senior Seismic Review and Advisory Panel (SSRAP) and the NRC staff. The scope of the review was narrowed down to equipment required to bring each affected plant to hot shutdown and maintain it there for a minimum of 72 hours. A walk-through of each plant was deemed necessary to inspect equipment in the scope. Evaluation of the equipment was to include: (a) adequacy of equipment anchorage; (b) functional capability of essential relays; (c) outliers and deficiencies (i.e., equipment with non-standard configurations); and (d) seismic systems interaction. Work completed on the issue resulted in the publication of NUREG/CR-3017,[1063] NUREG/CR-3875,[1064] NUREG/CR-3357,[1065] NUREG/CR-3266,[1066] NUREG-1030,[919] and NUREG-1211.[1067] The issue was RESOLVED when requirements were issued in Generic Letter 87-02.[1069] Verification of licensee actions was pursued with Generic Letter 87-03.[1387]

REFERENCES

44. NUREG-0705, "Identification of New Unresolved Safety Issues Relating to Nuclear Power Plant Stations," U.S. Nuclear Regulatory Commission, February 1981.

919. NUREG-1030, "Seismic Qualification of Equipment in Operating Nuclear Power Plants," U.S. Nuclear Regulatory Commission, February 1987.

1061. NUREG-0649, "Task Action Plans for Unresolved Safety Issues Related to Nuclear Power Plants," U.S. Nuclear Regulatory Commission, February 1980, (Rev. 1) September 1984.

1063. NUREG/CR-3017, "Correlation of Seismic Experience Data in Non-Nuclear Facilities with Seismic Equipment Qualification in Nuclear Plants (A-46)," U.S. Nuclear Regulatory Commission, August 1983.

1064. NUREG/CR-3875, "The Use of In-Situ Procedures for Seismic Qualification of Equipment in Currently Operating Plants," U.S. Nuclear Regulatory Commission, June 1984.

1065. NUREG/CR-3357, "Identification of Seismically Risk Sensitive Systems and Components in Nuclear Power Plants," U.S. Nuclear Regulatory Commission, June 1983.

1066. NUREG/CR-3266, "Seismic and Dynamic Qualification of Safety-Related Electrical and Mechanical Equipment in Operating Nuclear Power Plants," U.S. Nuclear Regulatory Commission, September 1983.

1067. NUREG-1211, "Regulatory Analysis for Resolution of Unresolved Safety Issue A-46, 'Seismic Qualification of Equipment in Operating Plants,'" U.S. Nuclear Regulatory Commission, February 1987.

1069. NRC Letter to All Holders of Operating Licenses Not Reviewed to Current Licensing Criteria on Seismic Qualification of Equipment, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46 (Generic Letter 87-02)," February 19, 1987.

1387. NRC Letter to All Licensees, Applicants and Holders of Operating Licenses Not Required to be Reviewed for Seismic Adequacy of Equipment Under the Provisions of USI A-46, 'Seismic Qualification of Equipment in Operating Plants,' "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46 (Generic Letter 87-03)," February 27, 1987.

1751. Letter to Seismic Qualification Advisory Committee (SQAC) and Meeting Attendees from G. Sliter and R. Vasudevan (EPRI), "Summary of the EPRI Seismic Equipment Qualification Research Coordination Meeting at ANCO Engineers, Inc., Los Angeles, California, September 19 & 20, 1984," October 10, 1984.

ITEM B-17: CRITERIA FOR SAFETY-RELATED OPERATOR ACTIONS

DESCRIPTION

Historical Background

This NUREG-0471[3] item involved the development of a time criterion for safety-related operator actions (SROA), including a determination of whether or not automatic actuation was to be required. At the time this issue was identified in 1978, existing plant designs were such that reliance on operators to take action in response to certain transients was necessary. In addition, some existing PWR designs required manual operations to accomplish the switchover from the injection mode to the recirculation mode following a LOCA. The required time for the ECCS realignment operations was dependent on the size of the pipe break, and the operation was expected to be accomplished before the inventory in the borated water storage tank was depleted. The evaluation of this issue included consideration of Issue 27.

Safety Significance

Development and implementation of criteria for SROA would result in the automation of some actions that were being performed by operators. The use of automated redundant safety-grade controls in lieu of operator actions was expected to reduce the frequency of improper action during the response to or recovery from transients and accidents, by removing the potential for operator error. This, in turn, could reduce the expected frequency of core damaging events and, therefore, reduce the public risk accordingly.

Possible Solutions

Plants would be required to perform a task analysis, simulator studies, and analysis and evaluation of operational data to assess existing ESF and safety-related control system designs for conformance to new criteria. Where non-conformance was identified, modification to existing designs and hardware would be required. For plants at the CP stage of review, changes and additions to the ESF control systems were anticipated, but replacement equipment costs were not anticipated.

PRIORITY DETERMINATION

Assumptions

In the analysis of this issue the following major assumptions were made:

(a) Operator error comprised 40% of total plant risk

(b) 10% of short-term emergency response actions were taken by operators

(c) 50% of long-term emergency response and recovery actions were taken by operators

(d) One-half of operator actions being taken in the short-term would be automated

(e) 20% of operator actions being taken in the long-term would be automated

(f) the failure rate of automated ESF controls was on the order of 10^{-4} /demand

(g) the failure rate of trained and practiced operators was on the order of 10^{-2} /demand in the highly stressed short-term period, and 10^{-3}/demand in the less stressful long-term period.

Frequency/Consequence Estimate

Using WASH-1400[16] frequencies, existing estimates of the doses to be expected for the various PWR and BWR release categories, and the projected population and remaining operating life of PWRs and BWRs, a total plant risk of 2.8×10^5 man-rem was determined. Operator contribution to total plant risk (40%) was thus estimated to be 1.12×10^5 man-rem. Of this risk, one-half was attributed to the short-term response period and one-half to the long-term response period.

Using the above stated assumptions on operator error and automated control system failure rates and the portion of short-term and long-term actions allocated to the operator, a short-term potential public risk reduction for completion and implementation of SROA criteria was estimated to be 2.8×10^3 man-rem. Resolution of the issue was estimated to provide a potential long-term public risk reduction of 5×10^3 man-rem. Thus, a total potential public risk reduction of 7.8×10^3 man-rem was estimated, and an average potential public risk reduction of 50 man-rem/reactor was estimated. Assuming an average core-melt consequence of 5×10^6 man-rem/event, a potential reduction of core-melt frequency of 3.8×10^{-7}/RY and 5.4×10^{-5}/reactor was estimated.

Cost Estimate

Industry Cost: Designers and/or operators of all plants were assumed to perform a design review and analysis of their existing ESF and safety-related control systems, and prepare modification packages for NRC review and approval. Comparison of existing designs to new criteria, preliminary design, final design, and NRC documentation were estimated to require 1 man-year/plant since most plants were multiple unit designs. Thus, the design cost for 143 plants was estimated to be $14.3M.

Equipment costs were divided into two groups: (1) older plants; and (2) recent and future plants. Recent and future plants were separated because of existing requirements for the automation of ECCS switchover to recirculation and automatic initiation of AFW systems. Backfit equipment and installation costs for older plants were estimated at $500,000/plant while the newer plants were estimated at $250,000/plant. Using the above breakdown on newer and older plants, a total equipment and installation cost of $53.7M was estimated. No additional recurring costs were estimated for operational maintenance and surveillance of the automated control systems since maintenance and surveillance would have been required for the manual control systems which were assumed to be replaced.

NRC Cost: The FY-1983 RES contract (FIN B0421) with ORNL included efforts by ORNL and its subcontractor (General Physics Corp.) to complete operator task analyses, simulator studies, operational data collection and analysis, and the development and recommendation of SROA criteria. This work was being pursued as part of Item I.A.4.2, "Long-Term Training Simulator Improvements."[48] Completion of the above efforts, review of the above, and development of SROA criteria, review and approval of new criteria, orders to licensees and applicants, and review and approval of licensee and applicant responses were estimated to cost \$4M over a 5-year period.

Total Cost: The total industry and NRC cost associated with the possible solution to this issue was estimated to be \$(4 + 14.3 + 53.7)M or \$72M.

Value/Impact Assessment

Based on a potential public risk reduction of 7.8×10^3 man-rem and an estimated cost of \$72M for a possible solution, the value/impact score was given by:

$$S = \frac{7.8 \times 10^3 \text{ man-rem}}{\$72M}$$

$$= 108 \text{ man-rem/\$M}$$

Other Considerations

Uncertainties for this analysis were very large due to the subjective nature of the approach to operator error reduction. It was acknowledged that a more deterministic design-specific analysis, which might be performed after the Item I.A.4.2 SROA criteria recommendations were developed, could have altered the value/impact score for this issue by one to two orders of magnitude in either direction.

CONCLUSION

The value/impact score calculated was indicative of a medium priority ranking (see Appendix C). It was recommended that, after the conclusion of the SROA criteria development efforts on Item I.A.4.2, a more rigorous analysis should be performed to reassess the value/impact associated with the adoption and implementation of specific SROA requirements which were not available at the time this issue was evaluated in March 1982.

In resolving the issue, the staff concluded that the following actions taken by licensees, in response to regulatory requirements issued since the issue was identified, addressed the safety concern: (1) enhanced operator training and licensing requirements, including plant-specific simulators; (2) improved training, based on the Systems Approach to Training for all covered staff; (3) implementation of symptom-based emergency operating procedures; and (4) the completion of the Individual Plant Examination (IPE) Program at all operating plants. Thus, the issue was RESOLVED with no new or revised requirements.[1766]

REFERENCES

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

16. WASH-1400 (NUREG-75/014), "Reactor Safety Study, An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants," U.S. Atomic Energy Commission, October 1975.

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.

1766. Memorandum to W. Travers from A. Thadani, "Proposed Resolution of Generic Issue B-17, 'Criteria for Safety-Related Operator Actions,'" March 27, 2000.

ITEM B-55: IMPROVED RELIABILITY OF TARGET ROCK SAFETY RELIEF VALVES

DESCRIPTION

The BWR pressure relief system is designed to prevent overpressurization of the reactor coolant pressure boundary (RCPB) under the most severe abnormal operational transient: closure of the main steam line isolation valves (MSIVs) with failure of the MSIV position switches to scram the reactor. This design function is accomplished through the use of a plant-unique combination of safety valves (SVs), power actuated relief valves (PARVs), and dual function safety/relief valves (SRVs). The majority of the valves in BWRs are commonly referred to as Target Rock SRVs.

In addition to the RCPB overpressure protection design functions of the BWR pressure relief system, a specified number of the PARVs or SRVs utilized in the pressure relief system of each BWR facility are used in the automatic depressurization system (ADS), which is one of the emergency core cooling systems. In the event of certain postulated small-break LOCAs, the ADS is designed to reduce reactor coolant system pressure to permit the low pressure emergency core spray and/or low pressure coolant injection systems to function. The ADS performs this design function by automatically actuating certain preselected PARVs or SRVs following receipt of specific signals from the protection system.

Certain safety concerns result when: (1) a valve fails to open properly on demand; (2) a valve opens spuriously and then fails to properly reseat; and (3) a valve opens properly but fails to properly reseat. The failure of a pressure relief system valve to open on demand results in a decrease in the total available pressure-relieving capacity of the system. Spurious openings of pressure relief system valves, or failures of valves to properly reseat after opening, can result in inadvertent reactor coolant system blowdown with unnecessary thermal transients on the reactor vessel and the vessel internals, unnecessary hydrodynamic loading of the containment systems' pressure suppression chamber (torus) and its internal components, and potential increases in the release of radioactivity to the environs. In addition, if the failed valve also serves as part of the ADS, a degradation in the capability of the ADS to perform its emergency core cooling function could result. This issue was documented in NUREG-0471.[3]

At the time of the evaluation of this issue in 1983, approximately 160 RY of operating experience had accumulated with a significant number of failures of the Target Rock valves occurring due to various causes. Studies and testing of these valves by the Owners' Group, in some cases at the suggestion of the NRC, have resulted in design changes in the valves and the issuance of several formal generic installation, operating, and maintenance instructions.[3]

In 1978, it was concluded[223] by the staff that the inadvertent blowdown events that had occurred to date, as a result of pressure relief system valve malfunctions, had neither significantly affected the structural integrity or capability of the reactor vessel, the reactor vessel internals, or the pressure suppression containment system, nor resulted in any significant radiation releases to the environment. The staff concluded that such events, even if they were to occur at a more frequent rate than that indicated by operating experience, would not likely have any significant effects on the reactor vessel or the vessel internals. It was also concluded that pressure relief valve blowdown events would not result in offsite radiological consequences appreciably different from those encountered during a normal reactor shutdown.

With respect to the pressure-suppression containment system, the slowly progressive nature of the material fatigue mode of failure associated with the dynamic loading conditions resulting from pressure relief valve blowdown events, and the substantial fatigue life margin available in the affected structures led the staff to conclude that additional short-term actions were not required to ensure that the integrity and functional capability of the system would be maintained. In addition, existing programs to provide additional containment system structural safety margins for the long-term (i.e., the anticipated 40-year lifetime of the BWR facilities) were acceptable. The performance of these valves, however, was under continuous surveillance and the consequences of their failures were subject to review.

PRIORITY DETERMINATION

Frequency Estimate

For potential core-melt frequency reduction, the Grand Gulf-1 BWR risk parameters were used in an analysis[64] of this issue. It was assumed that a final solution (negligible frequency of Target Rock valve malfunction) had not yet been achieved. Hence, failure rate data on these valves on existing reactors were applicable to this analysis. It was presumed that reactors with MARK III containments for which full operating licenses were pending did not use Target Rock valves.

Analyses of the effects of malfunctioning valves as separate failures indicated that, for the short-term, public safety was not of concern. The resulting thermal transients, even at the current rate of these events, were not likely to create concerns over pressurized thermal shock. The potential for radioactive release to the public following a malfunction resulting in an unplanned blowdown was no greater than for a normal shutdown. However, when a valve fails to reseat simultaneously with failures on other systems, some potential for a core-melt exists. Analysis of the dominant accident sequences at Grand Gulf-1 for these events was done as part of this evaluation.

All minimal cut sets in the following four Grand Gulf accident sequences were affected: T_1PQI (loss of offsite power with failure of the SRV to reseat and failures of the power conversion and RHR systems); $T_{23}PQI$ (normal transient with SRV reseat failure and failures of the power conversion and RHR systems); T_1PQE (loss of offsite power with SRV reseat failure and failures of the power conversion and ECCS); and $T_{23}PQE$ (normal transient with SRV reseat failure and failures of the power conversion and ECCS).

It was assumed that the resolution of the issue would result in a reduction in the frequency of valves failing to reseat by a factor of 4. This assumption was based on the continued success of the existing remedial programs for these valves that were underway at existing BWRs. The estimated change in core-melt frequency was 4.7×10^{-6}/RY.

Consequence Estimate

When the frequencies for the individual release categories are multiplied by the appropriate public dose and the products are summed, the resulting estimated change in public risk was 30 man-rem/RY. Assuming 10 reactors with an average remaining life of 26.7 years affected by the issue, the total risk reduction was estimated to be 8,000 man-rem.

Cost Estimate

Industry Cost: Modifying or refurbishing SRVs on high-temperature, high-pressure steam lines was expected to require engineering, design drawings, license review, testing, travel, labor, material, QA control, and management review. This cost was estimated[64] to be $75,000. In addition, new top works were estimated to cost $60,000 each and there were usually 11 SRVs/plant. Finally, it was estimated that 50 man-hours/RY would be required for operation (testing) and maintenance. There were 20 BWRs with Target Rock SRVs with an average remaining life of 26.7 years. Of these, about half had already installed new SRV top works. Thus, the total cost was estimated to be about $800,000/reactor for the remaining 10 reactors, or $8M.

NRC Cost: The NRC cost was reduced since the issue had been defined and partial solutions had been achieved. It was estimated that 4 staff-weeks/plant would be needed to support implementation. Thus, NRC cost was estimated to be about $150,000.

Total Cost: The total industry and NRC cost associated with the possible solution to the issue was estimated to be $(8 + 0.15)M or $8.15M.

Value/Impact Assessment

Based on a potential public risk reduction of 8,000 man-rem and an estimated cost of $8.15M for a possible solution, the value/impact score was given by:

$$S = \frac{8{,}000 \text{ man-rem}}{\$8.15\text{M}}$$

$$= 1{,}000 \text{ man-rem/\$M}$$

CONCLUSION

Based on the above safety priority score, the issue was given a medium priority ranking (see Appendix C). In resolving the issue, the staff found that licensees had significantly improved the performance of Target Rock SRVs and continued to evaluate and improve their performance. Licensee compliance with existing regulations, such as 10 CFR 50 Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," and 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," were sufficient for the staff to pursue additional improvements on a plant-specific basis, if needed. Thus, the issue was RESOLVED with no new or revised requirements.[1765]

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.

223. NUREG-0462, "Technical Report on Operating Experience with BWR Pressure Relief Valves," U.S. Nuclear Regulatory Commission, July 1978.

1765. Memorandum to W. Travers from S. Collins, "Closeout of Generic Safety Issue B-55, 'Improved Reliability of Target Rock Safety Relief Valves,'" December 17, 1999.

ITEM B-61: ALLOWABLE ECCS EQUIPMENT OUTAGE PERIODS

DESCRIPTION

Historical Background

This issue was identified in NUREG-0471[3] and addressed the establishment of surveillance test intervals and allowable equipment outage periods, using analytically-based TS criteria and methods. At the time the issue was identified, the allowable equipment outage intervals and test intervals in the existing TS were based primarily on engineering judgment.

Safety Significance

Studies showed that the unavailability contribution to the ECI/ECCS systems from testing, maintenance, and allowed equipment outage time ranged from 0.3 to 0.8 of the total unavailability. These studies were documented in March 1979 by Science Applications, Inc. in SAI-78-649 WA, "A Quantitative Approach for Establishing Limiting Conditions for Operation for ECCS/ECI Components in Commercial Nuclear Power Plants." Optimization of the allowed outage period and the test and maintenance interval could significantly reduce the equipment unavailability and, in turn, reduce public risk.

Possible Solution

Using available techniques and methods[124,138] and modeling from the IREP and NREP programs, the optimum equipment test intervals and allowable equipment downtimes could be determined. The TS would then have to be modified to conform to the resultant findings.

PRIORITY DETERMINATION

Assumptions

The reduction in core-melt frequency and public risk were computed for the Oconee-3 PWR. It was assumed that the risk reduction realized and the associated costs were typical for other PWRs. The allowable outage times could be varied, but the most significant improvement in equipment unavailability could result from decreasing the frequency of periodic tests and maintenance operations that require systems or components to be removed from service for the test or maintenance operation. This premise was valid only when the equipment failure frequency over the time span between tests or maintenance was much less than the unavailability that resulted from the removal of components for test or maintenance. As previously stated, allowed outage times contributed between 0.3 and 0.8 to the system unavailability and, neglecting the TS equipment allowable outage times, a reduction of 0.3 was chosen as a representative figure by which unavailability could be improved.

Frequency Estimate

Using Table 4-9 of NUREG/CR-1659,[54] Vol. 2, the core-melt frequency from LOCA sequences involving emergency core cooling through the loss of injection was determined, and the frequency of each release category was calculated as shown below:

Release Category	Frequency (per RY)
PWR-1	7.8×10^{-8}
PWR-2	0
PWR-3	2.5×10^{-6}
PWR-4	6.5×10^{-9}
PWR-5	6.1×10^{-8}
PWR-6	6.3×10^{-7}
PWR-7	6.5×10^{-6}

Assuming a core-melt frequency reduction of 30%, the frequency reduction in core-melt from LOCA was estimated to be 2.9×10^{-6}/RY.

Consequence Estimate

The above frequencies resulted in a public risk exposure of 14 man-rem/RY. Assuming a 30% core-melt frequency reduction would also result in a 30% reduction in risk, the reduced risk was 9.8 man-rem/RY, a reduction of 4.2 man-rem/RY. Assuming that the issue affected 95 PWRs with an average remaining life of 28.5 years, the total public risk reduction was estimated to be 11,400 man-rem.

Cost Estimate

Industry Cost: Assuming that the majority of the modeling was performed in the IREP or NREP analyses, the cost to institute the above changes would include performing the optimization analysis and revising the TS and other plant documentation accordingly. It was estimated that this would require up to 2 man-years/reactor. Thus, the implementation cost was estimated to be \$200,000/reactor. The cost of operation and maintenance would represent a saving since the resolution of the issue would result in an increase in the time interval between inspection and maintenance operations. However, this cost was conservatively estimated to be zero and the total industry cost was estimated to be \$200,000/reactor. For the 95 affected PWRs, this cost was \$19M.

NRC Cost: The NRC cost was estimated to be 2 man-months/reactor or \$4,000/reactor to review and approve the TS changes, and zero cost for operations. The cost to establish standard guidelines was estimated to be \$1,000/reactor. Therefore, the total NRC cost was estimated to be \$5,000/reactor. For the 95 affected PWRs, this cost was approximately \$0.5M.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be \$(19 + 0.5)M or \$19.5M.

Value/Impact Assessment

Based on a potential public risk reduction of 11,400 man-rem and an estimated cost of \$19.5M for a possible solution, the value/impact score was given by:

$$S = \frac{11{,}400 \text{ man-rem}}{\$19.5\text{M}}$$

$$= 580 \text{ man-rem/\$M}$$

Other Considerations

(1) This issue illustrated that degradation of availability can result when too frequent testing or maintenance is required of standby safety systems that must be removed from normal service to perform testing or maintenance. The small cost incurred for the enhancement of equipment availability, and the reduction in test and maintenance that would result, should make it attractive to the plant operators without the establishment of regulatory requirements.

(2) The benefit might have been estimated low by a factor of two, but increasing it by a factor of two would not change the priority ranking of the issue.

CONCLUSION

Based on the value/impact score and the potential public risk reduction, the issue was given a medium priority ranking (see Appendix C). In resolving the issue, the staff concluded that all aspects of the issue, other than the possible need for a limit on cumulative outage time, were addressed by the TSIP and the risk-informed TS guidance in Regulatory Guide 1.177[1735]; cumulative outage time was addressed by the Maintenance Rule (10 CFR 50.65). Thus, the issue was RESOLVED with no new or revised requirements.[1734]

REFERENCES

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

54. NUREG/CR-1659, "Reactor Safety Study Methodology Applications Program," U.S. Nuclear Regulatory Commission, (Vol. 1) April 1981, (Vol. 2) May 1981, (Vol. 3) June 1982, (Vol. 4) November 1981.

124. NUREG-0193, "FRANTIC - A Computer Code for Time-Dependent Unavailability Analysis," U.S. Nuclear Regulatory Commission, October 1977.

138. NUREG/CR-1924, "FRANTIC II - A Computer Code for Time Dependent Unavailability Analysis," U.S. Nuclear Regulatory Commission, April 1981.

1734. Memorandum for W. Travers from A. Thadani, "Resolution of Generic Safety Issue B-61, 'Analytically Derived Allowable Equipment Outage Periods,'" March 2, 1999.

1735. Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," U.S. Nuclear Regulatory Commission, August 1998.

ISSUE 23: REACTOR COOLANT PUMP SEAL FAILURES

DESCRIPTION

Background

This issue addressed the high rate of reactor coolant pump (RCP) seal failures that challenge the makeup capacity of the ECCS in PWRs. At the time this issue was identified[27] in 1980, RCP seal failures in BWRs occurred at a frequency similar to that experienced in PWRs. However, operating experience indicated that the leak rate for major RCP seal failures in BWRs was smaller. The smaller leak rate, larger RCIC, HPCI, and feedwater makeup capabilities, and isolation valves on the RCP loops negated the potential problem in BWRs. The three main PWR RCP manufacturers had their own seal designs that were developed throughout the years:

> BYRON-JACKSON supplies RCPs for the B&W and CE reactor systems. For a B&W system, pumps are supplied with three equally staged seals. For a CE system, the pumps are supplied with four seal stages: three stages are equally staged and the fourth stage is used as a vapor seal.
>
> BINGHAM originally had only two stages in their RCP design. At the time of the identification of this issue, the latest Bingham seal design, developed for pumps in B&W reactor applications, used three equally staged seals.
>
> WESTINGHOUSE used a three-stage seal design. The first seal stage takes the full system pressure, reducing the pressure from 2250 psi to 50 psi. The second stage is designed to take full system pressure in case of first-stage failure. The No. 3 seal is a vapor seal and operates at a pressure of not more than 5 psi.

Safety Significance

The results reported in WASH-1400[16] indicated that breaks in the reactor coolant pressure boundary having an equivalent diameter in the range of 0.5 to 2 inches were a significant cause of core-melt. Since then, a staff study[27] showed that comparable break flow rates have resulted from RCP seal failures at a frequency about an order of magnitude greater than the pipe break frequency used in WASH-1400.[16] It was believed that the overall probability of core-melt due to small-size breaks could be dominated by events such as RCP seal failures.[27]

Possible Solutions

It was believed that development efforts could be undertaken to supply much of the missing information and thereby provide a basis for new design specifications to obtain higher reliability in future seal designs. EPRI NP-1194[113] described a program to provide the information and physical insights necessary to make future RCP design considerably more reliable than existing designs. Such a program would include improved pump design, improved seal design, improved maintenance procedures, and improved seal auxiliary support systems. In addition, consideration of and coordination with Issue 9 (Reactor Coolant Pump Trip Criteria) was expected to provide a broader-based perspective of the RCP operational needs, performances, and requirements.

An apparent solution, but not necessarily the best solution,[114,195] was to replace each RCP seal annually. This solution was to be used to provide a cost estimate. The cost estimate, based on more frequent seal replacement, should bound an effective development program, or perhaps exceed the cost of needed (improved) maintenance and seal replacement procedures combined with improved instrumentation to detect incipient RCP failures.

PRIORITY DETERMINATION

Assumptions

The dominant accident sequences which follow a small-break LOCA, equivalent to a pipe break range of 0.38 to 1.2-inch diameter piping, was assumed to be representative of a RCP seal failure. The representative modeling provided by PNL[64] followed the RCP seal failure analysis used in the ANO-IREP study[366] in which thirty accident sequences were modeled in the RCP seal failure event tree. Assuming an RCP seal failure as the initiating event, two of the thirty accident sequences dominated the potential core-melt frequency. The two dominant accident sequences were: (1) failure of the high pressure injection system (D_1); and (2) failure of the high pressure injection system (D_1) and failure of the reactor building spray injection system (C). In both cases, containment failure was predicated by one of the following: vessel steam explosion (α); containment overpressure due to hydrogen burn (γ); penetration leakage (β); or base mat melt-through (ε).

The (D_1) failure assumed that the emergency signal will not be generated prior to core uncovery. In this case, the analysis[366] calculated that the pressurizer heaters could remain covered for an extended period and thus maintain RCS pressure above the emergency signal actuation set point. In the interim, the makeup (MU) tank could empty, resulting in loss of suction and failure of HPI/MU pump.

The (D_1C) sequence was similar to the (D_1) sequence except that the reactor building spray injection system (C) is also unavailable due to failure(s) which are common to the suction paths of the HPI pumps and spray pumps. In this sequence, all five (3 HPI plus 2 spray) pumps that take suction from the borated water storage tank could fail because of a failure of a single manual valve which is in series with two parallel MOVs.

Frequency Estimate

RCP Seal Failure Frequency: The RCP seal failure frequency of 2×10^{-2}/RY was used in the analysis.[64,366] This frequency represented a generic RCP seal failure frequency for major RCP seal failures that may challenge the ECCS (leaks $\geq$ 50 gpm/pump). Plant-specific RCP seal failure frequencies may have been higher or lower than this generic frequency. The overall RCP seal failure frequency, including smaller leaks, was approximately (0.5/RY).[114,195] This meant that, on an average, each PWR experienced a RCP seal failure biannually and that, during a 40-year design life, each PWR could experience one major RCP seal failure that would challenge the ECCS.

Core-Melt Frequency: Two core-melt frequencies were provided in the ANO-IREP Study.[366] One frequency estimate took no credit for operator recovery actions. The second estimate factored in potential recovery of failed systems. The recovery model basically considered three steps: (1) recoverability of the fault; (2) location of the fault; and (3) the critical recovery time for restoration of the component function.

The base case core-melt frequencies without recovery (W/O) and with recovery (R) for the two dominant accident sequences were:

D_1(W/O) $= 2.5 \times 10^{-5}$/RY

D_1C(W/O) $= 2.0 \times 10^{-5}$/RY

D_1(R) $= 2.8 \times 10^{-6}$/RY

D_1C(R) $= 4.4 \times 10^{-6}$/RY

Assuming a potential reduction in the major RCP seal failure frequency of 50% (1×10^{-2}/RY), the above core-melt frequencies would be reduced by a factor of 2.

Consequence Estimate

The major RCP seal failures contribute to 6 of the 7 PWR release categories. Based on a potential 50% reduction in RCP seal failure, the following table lists the affected PWR release categories, frequency reductions, and public risk (man-rem/RY) considered with and without recovery actions.

Category	**ΔCore-melt Frequency (/RY)**		**Risk (Man-rem/RY)**	
	(W/O)	**(R)**	**(W/O)**	**R**
PWR-1	2.3×10^{-9}	3.6×1^{-10}	12.1×10^{-3}	2.0×10^{-3}
PWR-2	1.2×10^{-5}	1.8×10^{-6}	5.5×10^{1}	8.7×10^{0}
PWR-4	0.7×10^{-7}	1.5×10^{-8}	11.4×10^{-1}	4.2×10^{-2}
PWR-5	0.9×10^{-7}	1.0×10^{-8}	0.9×10^{-1}	1.0×10^{-2}
PWR-6	0.5×10^{-5}	1.1×10^{-6}	7.0×10^{-1}	1.5×10^{-1}
PWR-7	0.7×10^{-5}	0.7×10^{-6}	3.0×10^{-2}	1.5×10^{-3}
TOTAL:	$\mathbf{2.4 \times 10^{-5}}$	$\mathbf{3.6 \times 10^{-6}}$	$\mathbf{5.77 \times 10^{1}}$	$\mathbf{8.8 \times 10^{0}}$
AVERAGE:	$\mathbf{1.36 \times 10^{-5}}$		$\mathbf{3.3 \times 10^{1}}$	

At the time of this evaluation in 1983, the average remaining life for 47 backfit and 43 forward-fit PWRs was 28.8 years which yielded a total of 2,592 RY. Thus, the total potential public risk reduction by reducing the RCP seal failure frequency 50% ranged from 2.28×10^4 to 14.95×10^4 man-rem. From the above values, it was apparent that operator recovery actions were important to public risk reduction.

A review of the ANO-IREP study[366] on RCP seal failures indicated that, in some sequences, non-conservative leak rates assumed in the IREP study could have resulted in an overestimation of the time available for an operator to take corrective action. Therefore, too much benefit may have been credited for recovery actions. In addition, if leak rates of 70 to 300 gpm were considered, as evident from some major RCP seal failures, the number of dominant accident sequences would most likely increase. Based on these observations which were to be confirmed in more detailed staff reviews, the potential public risk reduction was estimated to be 8.6×10^4 man-rem.

Cost Estimate

Industry Cost: A scheduled annual replacement of the RCP seals would involve TS changes. This one-time cost was estimated to be (2 man-weeks/plant)($2,270/man-week) or $4,540/plant. The license amendment fee for backfit plants was assumed to cost $12,300/plant. Considering 47 backfit plants and 43 forward-fit plants (no additional amendment fee), the industry cost was estimated to be $0.99M.

Operation and maintenance costs included labor and equipment (seals). The labor cost, assuming 300 man-hour/pump seal[431] and an average of 3.7 pumps/plant at a rate of $2,270/man-hour, was $63,560/RY. At $57,000/pump for 3.7 pumps/RY, the equipment (seals) would cost $210,900/RY. Therefore, the total estimated cost for annual replacement of all RCP seals for 90 PWRs over an average remaining life of 28.8 years was $710M.

From the above estimates, the dominant cost was attributed to the equipment (seals) cost ($547M). No outage (replacement power) costs were assumed since the seal replacements would be part of a planned outage schedule.

NRC Cost: The NRC cost was based on a flat rate of $2,270/man-week times the estimated number of man-weeks involved in the issue. The generic resolution was assumed to require 52 man-weeks of effort. Support for implementation of the resolution was estimated to be 2 man-weeks/plant. Annual review of the operation and maintenance and related concerns was estimated to be 0.2 man-week/RY. Therefore, the total NRC cost was estimated to be $[52 + (2)(90) + (0.2)(90)(28.8)][2,270] or $1.7M.

Total Cost: The total industry and NRC cost associated with a possible solution to the issue was estimated to be $[710 + 1.7]M or approximately $712M.

Value/Impact Assessment

Based on a potential public risk reduction of 8.6×10^4 man-rem and an estimated cost of $712M for a possible solution, the value/impact score was given by:

$$S = \frac{86{,}000 \text{ man-rem}}{\$712\text{M}}$$

$$= 121 \text{ man-rem/\$M}$$

Other Considerations

(1) The implementation cost impact based on annual seal replacements should bound a more effective resolution. A more effective solution would result in a greater cost benefit and lower ORE increases than annual seal replacements.

(2) Based on information in EPRI NP-2092[114] and a staff report,[195] the overall RCP seal failure (major and minor seal failures) frequency was ~0.5/RY. If this failure frequency and resultant unplanned outages were reduced by a factor of 2, the industry could realize a cost savings. Assuming 10 days per forced outage at a replacement power cost of $300,000/day for 90 plants over 28.8 years, the potential industry cost savings was estimated to be:

$$1/2\ \$[(5 \times 10^{-1})(10)(3 \times 10^{5})(90)(28.8)] = \$1{,}940\text{M}$$

(3) The total industry and NRC combined implementation cost of $712M was overwhelmed by the potential industry cost savings of $1,940M. Based on the above estimates, a resolution of this issue leading to a 50% reduction in RCP seal failures would result in a total combined cost benefit of approximately $1,200M.

(4) Annual replacement of all RCP seals would increase ORE. Based on information in EPRI NP-1138,[431] the average ORE for one pump seal replacement was 7 man-rem. Assuming an average of 3.7 pumps/plant/year over 28.8 years for 90 reactors yielded an ORE of (7)(3.7)(90)(28.8) man-rem or 6.7×10^4 man-rem. Assuming a potential reduction of 50% in RCP seal failures for the existing failure rate of 0.5/RY provided an ORE reduction of (0.5)(0.5)(7)(90)(28.8) man-rem or 4.5×10^3 man-rem. The net ORE for annual seal replacement was an increase of 6.3×10^4 man-rem or approximately 24.3 man-rem/RY. This potential increase in ORE and operating experience which showed that more frequent RCP seal replacements were ineffective in reducing RCP seal failures[195,114] indicated the need for a more effective solution than annual RCP seal replacements.

CONCLUSION

Depending on the assumptions, this issue could have been given a low priority ranking. However, this conclusion would have been based on an optimistic assessment of operator response, the high cost and large ORE incurred by annual seal replacement, and the exclusion of the down-time and associated costs due to minor seal failures.

If operator response is poor, then the potential reduction in public risk would justify a high priority. Other solutions may have been less costly and may have incurred less ORE, two factors which would have markedly improved the value/impact ratio. Any reduction in the overall RCP seal failure frequency would reduce unscheduled shutdown and the high associated costs. Therefore, based on the potential for a large reduction in public risk, the belief that better solutions could be found, and the potential for significant saving of replacement power cost, this issue was given a high priority ranking (see Appendix C) in November 1983. Prior to this, Issue 65 was integrated into the resolution of Issue 23.

In resolving the issue, the staff elected to pursue plant-specific backfits based on the staff's plant-by-plant risk analysis of the loss of component cooling water/essential service water systems. The staff also committed to work with the industry to develop additional RCP seal models to support future risk-informed licensing decisions. Thus, the issue was RESOLVED with no new or revised requirements[1763] and licensees were informed of the staff's conclusion in NRC Regulatory Issue Summary 2000-02.[1767]

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ISSUE 107: MAIN TRANSFORMER FAILURES

DESCRIPTION

Historical Background

This issue was identified in a DL/NRR memorandum[1183] which called for an assessment of the high failure frequency of main transformers and the resultant safety implications. Concern for this issue arose when the North Anna Power Station had seven main transformer failures in 26 months; five of these resulted in reactor trips. Of the seven failures, three included rupture of a transformer tank that resulted in two fires. One of the fires spread beyond the transformer bay to the turbine bay. In a report[1184] prepared for the NRC by LLNL, it was concluded that there was a possibility of generic implications arising out of the plant-specific failures reported for the North Anna units.

The potential generic concerns identified in the LLNL report[1184] included the fire protection system, overhead conductor/buses, cable trays, storage of flammable materials, and oil-filled transformers in general. In addition, certain secondary aspects of the transformer failures were identified which included cascading effects, extensive electrical/mechanical damage, and missiles/explosions, although the LLNL report noted that these latter items appeared to be either indirectly or remotely related to specific safety-significant concerns. Existing NRC regulations and guidance pertaining to fire protection and some of the generic concerns raised in the LLNL report[1184] are embodied in 10 CFR 50 Appendix R, the SRP,[11] and Regulatory Guide 1.120.[1185] In this analysis, the need for additional actions by the licensees to prevent main transformer failures and to reduce the resultant risk were evaluated.

Safety Significance

Safety-related loads in nuclear power plants are supplied from buses that can be supplied from any one of the following sources: (1) the unit auxiliary (main) transformer; (2) the startup transformer (or reserve auxiliary transformer); or (3) the emergency onsite power supply (i.e., diesel generators). A main transformer failure will result in a loss of load or unbalanced load on the main generator. This would lead to turbine/generator trip and power would not be available to the unit transformers for the station power; however, station power can be obtained from the grid through the startup transformer or from emergency onsite power sources. Switchyards have redundant systems to provide sufficient relaying and circuit breakers so a transformer failure is not expected to cause a loss of offsite power.

Other generic concerns associated with this issue included: (1) oil from a ruptured transformer could float on the water delivered to extinguish the fire by the fire protection system such that the fire will move in the direction of drainage; (2) the fire may propagate to overhead cables and buses and create the need for access to adjacent locations (such as building roofs) by fire-fighting crews.

Possible Solutions

Resolution of this issue could involve the following actions:

(1) Evaluation of main transformer design and arrangements by licensees to ensure that the supply of offsite power is protected against transformer fires and smoke. Design requirements should be established for routing and separation of offsite power source feeds to protect against power loss due to a transformer fire.

(2) Review of fire protection system features for the main transformers for adequacy and revision, as necessary, to ensure that a potential fire is prevented from spreading to other plant areas. The review should address the deluge system, drainage system, fire barriers, and fire-fighting equipment and procedures.

(3) Review of maintenance and operating procedures for the main transformers for adequacy and revision, as necessary.

(4) Modification of drainage systems, if necessary, to provide drains for each transformer so that liquids flow away from the turbine building, power lines, and safety-related cables to the reactor and related safety equipment. Modifications could include adding drains, building dikes, and sloping the transformer yard away from buildings and other transformers.

(5) Modification of fire-fighting equipment and procedures, if necessary. This could include longer hoses, increased ease of access to building roofs, mobility of fire-fighting equipment, and training for personnel.

(6) Relocation of power lines to the safety-related buses, if necessary, so that they would not be affected by a fire in the transformer bay.

PRIORITY DETERMINATION

To establish the priority of this issue, the potential reduction in core-melt frequency as a result of improved main transformer reliability due to implementation of the proposed solutions was quantified. It was believed that improved reliability of main transformers would reduce the frequency of transients induced due to main transformer failures, thus leading to enhanced plant safety.

Frequency Estimate

In the representative plant PRAs (Oconee-3 for PWRs and Grand Gulf-1 for BWRs), main transformer failures are integrated into a category of transients that result from loss of network load. The affected PRA parameters are transients other than loss of offsite power requiring or resulting in a reactor shutdown, i.e. T_2 (frequency of 3/RY) and T_{23} (frequency of 7/RY) for Oconee-3 and Grand Gulf-1, respectively. It was assumed that implementation of the possible solutions would enhance the reliability of main transformers and thus reduce the frequency of the resultant transients.

Data in NUREG/CR-3862[1186] on a specific transient category, characterized as a loss of incoming power to a plant as a result of onsite failure (such as main transformer failure), suggest that the transient frequency associated with this category is 0.02 event/RY. In addition, the IEEE reliability data for liquid-filled transformers (347 to 550 KVA) at nuclear power plants indicate that the main transformer failure rate due to all causes was 2.67/million-hours. This corresponded to an annual frequency of 0.023 failure/year for main power generator or unit transformers. This value was used as the base case for the failure frequency of main transformers. The second aspect of the main transformer failure, the risk from resulting fire, was determined to be insignificant and was not analyzed further. This conclusion was based on the findings of the Oconee-3 PRA which included the analysis of fires and their potential for causing failures of redundant safety-related components. Also, no particular sensitivity to main transformer fires was identified in NUREG/CR-5088.[1211]

It was assumed that implementation of the possible solutions (i.e., no design improvements to the transformer but improved maintenance and mitigative designs/procedures) would increase the reliability of main transformers by 50%. Therefore, the adjusted case main transformer failure frequency was estimated to be 0.01 event/RY. In addition, the adjusted case frequencies of the resultant transients (T_2 and T_{23}) were estimated as follows:

$$T_2 = (3 - 0.01)/RY = 2.99/RY$$

$$T_{23} = (7 - 0.01)/RY = 6.99/RY$$

Incorporating these values in the Oconee-3 and Grand Gulf -1 PRAs provide reductions in core-melt frequency estimates of 1.4×10^{-7}/RY for PWRs and 3.6×10^{-8}/RY for BWRs.

Consequence Estimate

This issue was assumed to be pertinent to all LWRs and thus had an affected population of 90 PWRs and 44 BWRs with average remaining lives of 28.8 years and 27.4 years, respectively. Based on the Oconee-3 and Grand Gulf-1 PRAs, the associated public risk reduction was estimated to be 0.38 man-rem/RY and 0.25 man-rem/RY for PWRs and BWRs, respectively. Thus, the average public risk reduction associated with this issue was 9.6 man-rem/plant.

Cost Estimate

Industry Cost: Implementation of the possible solutions at the affected plants would require review of existing systems and procedures and hardware changes. It was estimated that the review of the existing systems and procedures would require 15 man-weeks/plant at $2,270/man-week. These efforts would include evaluation of the fire protection systems, review of protective circuitry, review of operating and maintenance procedures, revision of operating and maintenance procedures, and revision of staff training. It was also assumed that, as a result of these reviews, about 10% of all affected plants would require hardware changes, modifications to fire protection systems, and re-routing of cables around the main transformer areas. It was estimated that 9 man-weeks would be required to prepare the design modifications and acceptance testing plan, install and test hardware changes, and revise procedures. Hardware and labor were estimated to cost $48,000/plant to provide the following: additional drains, gravel, and concrete to slope the area around the transformers and construct dikes; additional power lines to route power to the buildings; additional breakers to protect equipment connected to the auxiliary transformers; and longer fire hoses. The cost was itemized as follows:

Dike (250 ft. long, 4 ft. high)	=$	3,750
Concrete and Gravel	=	15,800
Power lines (1,000 ft)	=	5,000
Breakers (2 at $2500 each)	=	5,000
Fire Hose/Storage Cabinet (110 ft)	=	500

Note: An escalation factor of 1.8 was used by PNL to convert 1982 dollar values to 1988. Therefore, the cost to implement the possible solutions at 90% of the plants was about $30,000/ plant; for the remaining 10%, the cost was estimated to be $100,000/plant. The average cost for the affected population was approximately $40,800/plant.

For the affected plants, periodic review of main transformer procedures, operations, and maintenance was estimated to require 0.2 man-week/RY. At a cost of $2,270/man-week, this amounted to $450/RY. In addition, those plants requiring hardware modifications (10% of affected plants as discussed above) require 1 man-week/RY (or $2,270/RY) for periodic maintenance/inspection of drains and new diked areas, removal of trash from drains, etc. Plant maintenance and operation costs are recurring costs and were adjusted for present worth at a 5% discount rate over the 28.3-year average remaining plant life for the 134 affected plants. This resulted in an average plant cost (present worth) of $11,200/plant.

It was believed that improvements to the reliability of main transformers and improvements to fire protection systems could potentially result in: (1) avoided costs of replacing a transformer damaged by fire (3 out of 14 transformer failures resulted in fire, or 0.002 main transformer failure/RY); and (2) avoided replacement power costs associated with reducing the number of reactor trips caused by main transformer failures.

<u>NRC Cost</u>: NRC costs consisted of initial regulatory development and the resources required in support of the regulatory implementation. The initial regulatory development cost could involve the issuance of a generic letter or bulletin to the licensees, review of licensee responses, other related activities (i.e., revised design guidance, assessment of differences in plant design related to transformers, development of potential implementation measures), and the required technical, legal, and administrative staff labor. This portion of resource requirements was estimated to require 40 man-weeks ($90,000) in addition to potential outside contractor support (estimated to cost $50,000) for a total of approximately $140,000. Averaging this over the 134 affected plants resulted in an approximate NRC cost of $1,000/plant.

The implementation resource requirements consist of NRC labor to review utility plans to comply with revised guidance and additional inspection and monitoring of transformer maintenance/testing programs during the routine NRC plant inspections. This was estimated to require $4.1M over the life of all affected plants. These costs are also recurring costs and when adjusted for present worth, as indicated above, resulted in an average NRC cost (present worth) of $17,000/ plant.

<u>Total Cost</u>: The total industry and NRC cost associated with the possible solution was estimated to be $70,000/plant.

Value/Impact Assessment

Based on a potential public risk reduction of 9.6 man-rem/reactor and an estimated cost of \$70,000/reactor for a possible solution, the value/impact score was given by:

$$S = \frac{9.6 \text{ man-rem/reactor}}{\$0.07\text{M/reactor}}$$

$$= 137 \text{ man-rem/\$M}$$

Other Considerations

(1) Implementation of the possible solutions was assumed not to involve any labor in radiation zones because the main transformers are not located in a building in which radioactive materials are used or stored and thus the radiation dose rates are zero.

(2) The core-melt frequency reductions of 1.4×10^{-7}/RY for PWRs and 3.6×10^{-8} /RY for BWRs results in ORE avoidance associated with core-melt cleanup operations of 20,000 man-rem/core-melt.[64] The accident avoidance over the remaining plant life was [(28.8)(90)(1.4 x 10^{-7}/RY) + (27.4)(44)(3.6 x 10^{-8}/RY)] (20,000)/134 or 0.06 man-rem/plant. The present worth cost of a core-melt accident was estimated to be \$1.65 billion considering cleanup and replacement power cost over a ten-year period.[64] The present worth of accident avoidance at each plant was estimated to be [(28.8)(1.4 x 10^{-7}/RY)(90) + (27.4)(3.6 x 10^{-8} /RY)(44)](\$1,650M)/134 or \$5,000.

(3) Existing designs of operating nuclear power plants incorporate various independent means of supplying loads so that main transformer failures would not cause a total loss of offsite power. In addition, the promulgation of the station blackout rule (10 CFR 50.63) should further reduce the risk from loss of AC power from that considered in the Oconee-3 and Grand Gulf-1 PRAs.

(4) It was believed that implementation of the possible solutions could be accomplished during normal plant outages and would not require design modifications or work in radiation zones. The relatively high failure frequency of the main transformers at the North Anna plant highlighted a possible need for plant-specific evaluations by some licensees to review their main transformers and to implement an appropriate combination of the alternatives proposed in order to enhance safety.

CONCLUSION

Based on the above value/impact score, the issue was on the borderline between a low and medium priority for existing plants. However, it was believed that the risk estimates were high (because the effect of the station blackout rule was not included in the Oconee-3 and Grand Gulf -1 PRAs). Therefore, the issue was given a low priority ranking (see Appendix C) for existing plants.

Following a periodic review of low priority issues, NRR provided new information[1749] on transformer failures that required a reevaluation of the issue. Further prioritization, using the conversion factor of \$2,000/man-rem approved[1689] by the Commission in September 1995, resulted in an impact/value ratio (R) of \$11,565/man-rem which placed the issue in the DROP category.[1750]

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ISSUE 115: ENHANCEMENT OF THE RELIABILITY OF WESTINGHOUSE SOLID STATE PROTECTION SYSTEM

DESCRIPTION

Historical Background

The ATWS rule[724,725] for W plants requires the implementation of a diverse ATWS mitigation system, Auxiliary [or ATWS] Mitigating Systems Actuation Circuitry (AMSAC). The functions prescribed for AMSAC are turbine trip and the initiation of auxiliary feedwater, independent of the reactor trip system.

As a consequence of the Salem ATWS event (Issue 75), Generic Letter 83-28[520] established the requirement for the automatic actuation of the shunt trip attachment of reactor trip breakers for W and B&W plants (this feature was included in the original design for CE plants). Although this modification provided a significant increase in the reliability of the reactor trip breakers and hence the reactor trip system, it had not been previously pursued as an action that would significantly reduce the potential of an ATWS event during the extensive dialogue and study of the ATWS issue. Further, it was believed that other similar actions to increase the reliability of the existing reactor trip system for W plants also had not received such consideration.

With respect to W plants with the solid state protection system (SSPS) design, failures of the undervoltage (UV) driver raised concerns with regard to the susceptibility of the design to common mode and random failures of redundant components. Enhancement of the reliability of the W SSPS was suggested by DSI/NRR as a new generic issue in April 1985.[905]

Safety Significance

The failures of the UV driver suggested a higher probability of SSPS failure than that calculated during the ATWS rulemaking proceeding. The higher probability of SSPS failure in turn would lead to a higher probability of ATWS and, as such, would represent a higher risk to the offsite population surrounding the affected plants. At the time of the evaluation of this issue in July 1986, the affected plants were those W plants with the SSPS, i.e., 19 of the 38 operating W plants.

Possible Solution

It was believed that incorporation of additional diversity for the UV driver function would reduce the probability of an ATWS event. In particular, it was assumed that the UV driver reliability could be improved by installing a relay driver and associated relays to duplicate the function of the UV driver, thereby providing diversity for the function.

PRIORITY DETERMINATION

Assumptions

It was assumed that the AMSAC required by the ATWS rule for W plants was in place and operational.

Frequency Estimate

Reliability block diagrams for the W SSPS were used in the calculation of frequency estimates of core damage events as a result of SSPS failures. These figures were provided to the staff as part of the W Owners Group response to staff questions during the review of WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection System," (Proprietary).

Diversity exists in two basic forms. The first is from the standpoint of measured parameters and sensors that initiate a reactor trip, and the second is the diverse trip features of the reactor trip breakers (shunt and UV trip coils). For the analog channels, comparators are the major component that are common to each channel. For the logic cabinet, input relays and the universal (logic) cards are common for each trip function, with the UV driver common to all trip functions. For the reactor trip breakers, the remaining components (primarily mechanical) are common to all trip functions.

Table 3.115-1 summarizes the estimates for common mode failures of the protection system on the bases of the listed failure rates, a Beta factor of 0.01 and a monthly test interval. A Beta factor of 0.01 was used to be consistent with that used for logic channels as noted in SECY 83-293.[904] TS required testing of breakers and logic every 62 days on a staggered test basis (one train or the other is tested every 31 days such that the time interval for finding common mode failures would be monthly). Based on the review of WCAP-10271, the staff approved quarterly testing of analog channels. Since the majority of the trip functions consisted of 3 or 4 channels, quarterly tests on a staggered test basis for a 3-channel system resulted in one channel being tested monthly. Thus, a monthly test interval was also used for analog channels.

The channel comparators were the major contributor to the common mode failure unavailability since they have the largest hourly failure rate. However, if the hourly failure rate for the UV driver was estimated based on the five known failures and an estimate of 90 RY for W plants that had the SSPS with two UV drivers, the common mode failure unavailability of the UV driver (see Table 3.115-2) would become the dominant contributor.

In addition to initiating reactor trip, the SSPS is used to initiate engineering safeguard systems. While these functions of the reactor protection system use many of the same components as the reactor trip system (comparators, logic input relays, and universal logic cards), the reactor protection system differs from the reactor trip system in its final output configuration. Instead of a UV driver that turns off 48V DC to the actuated component, a relay driver is provided which supplies 48V DC to energize a master relay which, in turn, energizes slave relays that provide contacts to actuate engineered safeguard components. Thus, a relay driver and associated relays could be used to duplicate the function of the UV driver for the reactor trip function and thereby provide diversity. This would eliminate common mode failures of the UV driver as the dominant contributor to the probability of an ATWS event due to protection systems failures (see Table 3.115-3).

The event trees used by the ATWS Task Force were altered to substitute the above estimates of SSPS electrical unavailability for the value previously used to estimate a base case frequency of core damage events and a CDF after supplementing the UV driver function. Values for the probability of all other events were those used by the ATWS Task Force. The specific events incorporated into the event trees were: number of transients (AT); MTC overpressure; SSPS mechanical failure; auxiliary feedwater failure; and high pressure injection (HPI) failure.

TABLE 3.115-1

Components	λ	Common Mode[a] Failure Unavailability (10^{-5})
Channel Comparators	2.90×10^{-6}/hr	1.100
Logic Input Relays	8.70×10^{-8}/hr	0.032
Universal Logic Cards	7.70×10^{-7}/hr	0.290
Undervoltage Driver	1.95×10^{-7}/hr	0.073
Breaker Mechanical Components	1.95×10^{-8}/hr	0.031
TOTAL:		1.530

a - U = BλT/2 (Average unavailability due to common mode failure)

TABLE 3.115-2

Undervoltage Driver Failures	5	
Reactor-Years (Est) SSPS Plants		90
Failure Rate, λ		0.028/yr (3.17×10^{-6}/hr)
Common Mode Failure Probability[a]		1.14×10^{-5}
All Other Components $(1.53 - 0.073) \times 10^{-5}$		1.46×10^{-5}
Total Failure Probability		2.60×10^{-5}

a - U = BλT/2 (Average unavailability due to common mode failure)

The base case frequency of core damage events was estimated to be 8.9×10^{-6}/RY when the five UV driver failures were considered. The frequency of core damage events was estimated to be 4.7×10^{-6}/RY when the increased reliability of SSPS afforded by supplementing the UV driver function was considered. This resulted in a reduction in core-melt frequency of 4.2×10^{-6} /RY for the proposed modification to the SSPS.

TABLE 3.115-3
Total System Unavailability

Event	Existing System	Diverse UV Driver
Common Mode failures	2.60×10^{-5}	1.46×10^{-5}
Random failures	4.33×10^{-6}	(b)
Testing	6.34×10^{-6}	(b)
TOTAL:	3.67×10^{-5}	1.46×10^{-5}

b - The additional diversity decreases the random failure unavailability to less than 10^{-6} and eliminates testing unavailability.

Consequence Estimate

The total whole-body man-rem dose was obtained using the CRAC Code results.[64] These results assumed a uniform population density of 340 people per square-mile (which was the average for U.S. domestic sites in the year 2000) within the area between ½- and 50-mile radius from the plant. Typical (Midwest plain) meteorology, no evacuation, and no ingestion pathway were also assumed. The Oconee-3 RSSMAP study had been adopted as the evaluation model for PWRs and was, therefore, assumed to adequately represent the selected group of affected plants for this issue. In the Oconee-3 RSSMAP, the only ATWS dominant risk sequence (T_2KMU) was assumed to result in a Category 3 release with a probability of 0.5, a Category 5 release with a probability of 0.007, and a Category 7 release with a probability of 0.5. Thus, a weighted average of 2.7×10^6 man-rem/event for the consequences of ATWS events was derived using the CRAC Code results. (It should be noted that the ATWS Task Force assumed a consequence, in terms of public exposure, of 10^7 man-rem/event in arriving at its recommendations.)

The 19 W operating plants utilizing the SSPS had an average remaining life of 25.5 years. When the estimated reduction in core-melt frequency (4.2×10^{-6}/RY) was multiplied by the average consequence (2.7×10^6 man-rem/event), the number of affected plants (19 plants) and the average remaining life of the affected plants (25.5 years), an estimate of 5,500 man-rem was obtained.

Cost Estimate

Industry Cost: Based upon discussions with plant operators, the following licensee implementation costs were identified:

(1) Engineering analysis of the problem was estimated to take about 2 man-weeks to design and document the modifications to the SSPS. At \$2,270/man-week, this was estimated to cost \$4,540.

(2) Relays and other hardware were assumed to cost \$3,000.

(3) Installation was assumed to require 1 man-week at an estimated cost of $2,270. Since this modification could be completed during normal outage time, no replacement power cost was included.

(4) Possible TS changes were assumed to require 4 man-weeks. At $2,270/man-week, this was estimated to cost $9,080.

In addition, it was assumed that, following completion of the modifications to the scram system of the SSPS, a functional (acceptance) test would be necessary. It was estimated that this test would take the better part of a shift to perform and would involve time from the shift supervisor, systems engineering, control room operators, and I&C technicians. The functional test was estimated to take 42 man-hours at a cost of $2,400/plant. QA efforts during the design, installation and testing of the scram system modifications and during the development of TS revisions were estimated to take an additional 66 man-hours for a cost of $3,800/plant.

The cost of the above requirements was estimated to be about $25,000/plant for a total licensee implementation cost of $475,000 for the 19 affected plants. The affected plants were assumed to not require any additional operation/maintenance beyond that normally required. Therefore, the licensees' operation and maintenance cost was zero.

NRC Cost: It was estimated that the NRC labor requirement for development of requirements was 8 man-weeks. At $2,270/man-week, this was estimated to be $18,160. The cost for a technical assistance contractor was assumed to be $20,000. Therefore, the total NRC cost for development of requirements was ($18,160 + $20,000) or $38,000.

NRC cost tracking had shown that, on the average, about 1.7 staff-years were required to process a generic requirement from the point where it is acted on by the CRGR until its resolution in the form of a specific MPA. At approximately $135,000/staff-year, this amounted to about $230,000. In light of the relatively large societal risk and the rather small industry cost estimated for this issue, it was assumed that the NRC requirement processing cost would be less than the existing average and would be about $150,000.

Using historical cost information provided in NUREG/CR-3971,[906] the NRR implementation cost/plant was estimated for the plant-specific review of licensee design changes, the review and processing of plant-specific TS changes, and OIE review of the licensees' implementation actions. The estimated NRC implementation costs/plant were:

NRC Design Review	$ 6,000
TS Review and Processing	14,000
OIE Implementation Review	4,000
TOTAL:	$24,000

For the 19 affected plants, the NRC implementation cost was estimated to be $456,000. Since no additional operational/maintenance costs were estimated for the licensees, no additional costs for NRC review of the licensees maintenance and testing were estimated. Thus, the total NRC cost was estimated to be $644,000.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $1.12M.

Value/Impact Assessment

Based on a potential public risk reduction of 5,500 man-rem and an estimated cost of \$1.12M for a possible solution, the value/impact score was given by:

$$S = \frac{5.5 \times 10^3 \text{ man-rem}}{\$1.12\text{M}}$$

$$= 4.9 \times 10^3 \text{ man-rem/\$M}$$

Other Considerations

Reduction in the frequency of core damage events would result in an averted ORE for cleanup of the 19 affected plants. When a value of 19,900 man-rem/event for ORE following a severe core damage event was multiplied by the change in core-melt frequency, the number of affected plants and their average remaining life, an averted ORE of about 40 man-rem was estimated. Likewise, the rather large reduction in core-melt frequency would also result in an appreciable averted accident savings to the licensee. At a cost of \$1.65 billion per core-melt event, the averted accident savings for this issue was calculated to be \$3.3M.

Based on discussions with plant operators, the assumed modifications to the SSPS would not require labor for installation or maintenance in a radiation zone. Therefore, no ORE was estimated for these efforts.

The proposed modifications to the SSPS might result in an increase in the frequency of inadvertent or spurious trips which would represent an economic loss to the industry due to lost power production/replacement power costs. This was not considered in this analysis but should be estimated and accounted for in the resolution of this issue and the development of a regulatory analysis for any proposed new requirement(s).

CONCLUSION

Based on the potential risk reduction and the high value/impact score, the issue was given a high priority ranking (see Appendix C). In pursuing a resolution to the issue, W investigated the five UV driver card failures and determined that they were caused by poor maintenance and test-related practices. These practices involved the inadvertent shorting of the scram breakers' UV trip coil, causing a shorted failure of the output transistor in the UV card. To eliminate this safety problem, W modified the design of the UV card to provide a fuse link in the output circuit which will open the circuit when the UV coil is shorted. This will produce a UV trip signal to the scram breaker which will persist until the card is removed, repaired (by W), and replaced.

W Technical Bulletin NSID-T8-85-16 dated July 31, 1985, was issued to the W utilities, as required by the Salem ATWS Generic Letter (83-28),[520] recommending installation of the modified UV cards. The Bulletin also recommended specific maintenance and test procedures that should be followed to prevent failures of this type pending installation of the modified UV cards. It was expected that the affected W licensees would take action to modify their test and maintenance procedures and to procure and install the modified UV driver cards. The staff sought verification of the licensees' responses to the W recommendations. The W recommended solution was not viewed as providing the same degree of risk reduction as that which could be altered by providing diversity for the UV drive scram function. Resolution of the issue was expected to take into consideration the potential risk reduction afforded by the W "fix," if it was adopted by the affected licensees, and a determination was to be made as to whether any further risk reduction offered by providing diversity for the UV driver scram function could be justified by value/impact analysis.

During the course of resolving the issue, the staff gained certain insights which were deemed to be useful in improving the reliability and overall performance of reactor protection systems. These insights were suitable for industry initiatives to improve safety and to reduce the regulatory burden on the affected licensees while extending the life of reactor trip breakers. The staff's technical findings were documented in NUREG/CR-5197[1200] and the regulatory analysis was published in NUREG-1341.[1201] Thus, the issue was RESOLVED with no new or revised requirements.[1202]

In March 1999, a follow-up study of the reliability of risk-significant safety systems resulted in the publication of NUREG/CR-5500,[1752] Volume 2. This study provided an estimate of the reactor protection system unavailability based on actual and test demands between 1984 and 1995, and identified dominant contributors to potential system failure. Recommendations for improving risk-informed regulatory activities were made.[1753]

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905. Memorandum for T. Speis from R. Bernero, "Enhancement of the Reliability of W Solid State Protection Systems (SSPS)," April 5, 1985.

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1200. NUREG/CR-5197, "Evaluation of Generic Issue 115, 'Enhancement of the Reliability of Westinghouse Solid State Protection System,'" U.S. Nuclear Regulatory Commission, January 1989.

1201. NUREG-1341, "Regulatory Analysis for the Resolution of Generic Issue 115, 'Enhancement of the Reliability of the Westinghouse Solid State Protection System,'" U.S. Nuclear Regulatory Commission, May 1989.

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1752. NUREG/CR-5500, "Reliability Study: Westinghouse Reactor Protection System, 1984 - 1995," U.S. Nuclear Regulatory Commission, (Vol. 2) April 1999.

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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[1119] 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 IPEs, and encourage licensees to conduct an engineering analysis and to provide training to plant personnel so that 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.[1119] 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 each 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	$\mathbf{2.4 \times 10^{-5}}$	$\mathbf{1.6 \times 10^{-5}}$	$\mathbf{8.3 \times 10^{-6}}$	**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/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 life of 28.8 years for a PWR, the estimated risk reduction associated with this issue was (5.35×10^{-6}/RY)(2.5×10^6 man-rem)(28.8 years) or 385 man-rem/reactor. Based on an average remaining life of 27.4 years for a BWR, the estimated risk reduction was (3.3×10^{-6}/RY)(6.7×10^6 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 1 (preparation of an information notice and a CCF summary report) was estimated to be about $200,000.

Total Cost: The maximum industry and NRC 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 public risk reduction of 385 man-rem/reactor and an estimated cost of $1.1M/reactor for a possible solution, the value/impact score was given by:

$$S = \frac{385 \text{ man-rem/reactor}}{\$1.1\text{M/reactor}}$$

$$= 350 \text{ man-rem/\$M}$$

BWRs: Based on a potential public risk reduction of 606 man-rem/reactor and an estimated cost of $1.1M/reactor for a possible solution, the value/impact score was given by:

$$S = \frac{606 \text{ man-rem/reactor}}{\$1.1\text{M/reactor}}$$

$$= 551 \text{ man-rem/\$M}$$

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 license renewal period for operating reactors, the estimated risk reduction for a PWR was (5.35×10^{-6}/RY)(2.5×10^{6} man-rem)(48.8 years) or 653 man-rem/reactor. For a BWR, the estimated risk reduction was (3.3×10^{-6}/RY)(6.7×10^{6} man-rem)(47.4 years) or 1,048 man-rem/reactor.

CONCLUSION

Based on the potential public risk reduction, this issue would have been 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 identify CCFs; this action essentially addressed Solutions 2 and 3. Since much CCF information had been generated over the years, it was likely to be beneficial to pursue Solution 1. It was believed that this action would not require any additional research and could be accomplished in the near term. Thus, based on the extent of the ongoing work, the issue was considered nearly-resolved[1754] in February 1992 but was later given a high priority ranking in SECY-98-166.[1718] In accordance with an RES evaluation,[1564] the impact of a license renewal period of 20 years was to be considered in the resolution of the issue.

In resolving the issue, the staff developed a CCF database and analysis software package to aid in system reliability analyses and related risk-informed applications. The CCF database was documented in NUREG/CR-6268[1755] which, in addition to providing guidance on the screening and interpretation of data, contained relevant event data to provide a more uniform and cost-effective way of performing CCF analyses. The database contained CCF-related events that occurred in U.S. commercial nuclear power plants from 1980 to 1995. Licensees were informed of the availability of the CCF database in Administrative Letter 98-04[1756] and Regulatory Issue Summary 99-03[1757] was issued to make the major insights derived from the CCF research project more readily available to plant managers. Thus, the issue was RESOLVED with no new or revised requirements.[1758]

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1119. NUREG/CR-4780, "Procedures for Treating Common Cause Failures in Safety and Reliability Studies," U.S. Nuclear Regulatory Commission, (Vol. 1) January 1988, (Vol. 2) January 1989.

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ISSUE 148: SMOKE CONTROL AND MANUAL FIRE-FIGHTING EFFECTIVENESS

DESCRIPTION

Historical Background

This issue was raised in SECY-89-170[1320] and addressed the effectiveness of manual fire-fighting in the presence of smoke. This concern 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. In addition, Item 2.3c, "Smoke Control," identified in NUREG-1251[1174] expressed concern over smoke propagation from one unit to an adjacent unit.

In general, lubricating oils and cable insulation are the primary fire sources found in nuclear power plants. Both of these sources represent the most prolific smoke-generating fuel. Experimental evidence indicates that burning such fuels in a typical nuclear power plant enclosure would obscure the entire enclosure in about 10 minutes.[1407] In actual experience, fire-fighters have had difficulty in seeing the fire source because of smoke (Browns Ferry, 1975) and equipment is known to have failed in smoke-filled environments.

Safety Significance

Smoke can impact plant risk in several ways:

(1) Smoke can reduce manual fire-fighting effectiveness, cause misdirected suppression efforts, and subsequently damage equipment not directly involved in the fire.

(2) Electronic equipment can be damaged or degraded by smoke resulting in functional loss or spurious response. Very little experimental data on equipment response in smoke environments were available at the time this issue was evaluated in August 1992 and the methodology for including smoke in PRAs had not been adequately developed. Additional research efforts were believed to be required to fully address the risk impact of smoke on safety-related systems.

(3) Smoke can hamper an operator's ability to safely shutdown a plant by causing evacuation of control centers and subsequent reliance on backup shutdown capability.

(4) Smoke can initiate automatic fire protection systems in areas away from the fire, potentially damaging safety systems and components. (This item was addressed separately in Issue 57, "Effects of Fire Protection System Actuation on Safety-Related Equipment.")

NUREG/CR-5088[1211] focused primarily on Item 1. Using information developed as part of the Risk Methods Integration and Evaluation Program (RMIEP) on the response of fire-fighters to specific areas of the LaSalle plant, sensitivity studies were performed on four PRAs. These studies showed the variation in CDF as a result of fire-fighting response time and misdirected suppression efforts. A discussion of the methods used and results of the study are provided below.

Impact of Manual Fire-Fighting Response Time: Smoke can increase fire risk by prolonging fire-fighting response time. With the LaSalle nuclear plant as a model, walkdowns by fire protection engineers as part of the Fire Risk Scoping Study[1211] established bounds on the time to detect, apply suppression agents, and successfully suppress fire for all critical plant areas. This information was then applied to the previously reviewed fire-initiated core damage scenarios in the four selected PRAs (Oconee, Seabrook, Limerick, Indian Point-2).

Thirteen plant areas were grouped by area, equipment contained in the area, available suppression equipment, and type of detection. These areas were partitioned into the following five groups:

(1) Oconee (Cable Shaft), Indian Point-2 (Electrical Tunnel, Cable Spreading Room), Seabrook (Cable Spreading Room)
(2) Seabrook (Control Room)
(3) Seabrook (Turbine Building)
(4) Limerick (13 kv Switchgear Room), Oconee (Electrical Equipment Room), Indian Point-2 (Switchgear Room)
(5) Seabrook (PCC Pump Area), Limerick (Safeguards Access Area, CRD Hydraulic Equipment Area, General Equipment Area)

However, only the analyses of Groups 1, 4, and 5 specifically considered the effect of manual suppression efforts on the mitigation of critical damage. The control room area, Group 2, did not allow successful suppression, and Group 3, the Seabrook Turbine Building, did not lead to core damage. Group 1 corresponded to the LaSalle cable spreading room, while Groups 4 and 5 corresponded to the LaSalle essential switchgear room and large areas of the reactor building, respectively. The results are shown in Table 3.148-1. The minimum and maximum times are representative of the most and least effective fire brigades, respectively, and the average time represents a typical fire brigade. Although the time to detect the fire, report to the suit-up area, and suit-up are all important contributors to the response time, the major time elements (up to 75%) include: (1) response to scene; (2) set-up at scene; (3) scene search; and (4) time to suppression or substantial control. Given a smoke-filled environment, times associated with each of the these four elements can be prolonged substantially.

Impact of Misdirected Suppression Efforts: NUREG/CR-5088[1211] assessed the effect on CDF of a fire brigade damaging equipment not directly involved in the fire. The assessment included:

(1) Identification of components susceptible to spray, flooding, or temperature within the fire area.

(2) PRA re-quantification, assuming susceptible components fail by suppression efforts.

(3) Identification of important areas and probability of spraying essential equipment not involved in the fire but located in those areas.

(4) Combined with fragility information, determination of the conditional probability of suppression-induced failure.

Table 3.148-1
Effects of Fire Brigade Response and Extinguishment Time on CDF Due to Fire

Plant	Area	CDF/Year Response and Extinguishment Time			
		Minimum	Average	Maximum	Original PRA Value
Seabrook	Cable Spreading Room	8.0×10^{-7} (mean)	4.9×10^{-6}	8.9×10^{-6}	4.1×10^{-6}
	PCC Pump Area	1.4×10^{-5} (mean)	6.2×10^{-5}	1.0×10^{-4}	7.2×10^{-5}
Oconee-3	Cable Shaft	5.3×10^{-6} (point estimate)	1.1×10^{-5}	1.4×10^{-5}	1.0×10^{-5}
	Electrical Equipment Room	5.4×10^{-9}	1.5×10^{-8}	2.0×10^{-8}	1.6×10^{-8} (point estimate)
Indian Point-2	Cable Spreading Room	1.1×10^{-7}	1.2×10^{-6}	2.5×10^{-6}	1.9×10^{-6} (mean)
	Electrical Tunnel	9.3×10^{-6}	4.7×10^{-5}	7.6×10^{-5}	5.0×10^{-5} (mean)
	Switchgear Room	2.2×10^{-6}	3.0×10^{-5}	6.3×10^{-5}	5.6×10^{-5} (mean)
Limerick	13 kv Switchgear Room	6.0×10^{-7}	4.7×10^{-6}	2.8×10^{-5}	6.2×10^{-6} (point estimate)
	Safeguards Access Area	1.4×10^{-6}	8.5×10^{-6}	3.8×10^{-5}	6.0×10^{-6} (point estimate)
	CRD Hydraulic Equipment Area	5.0×10^{-7}	8.3×10^{-6}	2.1×10^{-5}	6.4×10^{-6} (point estimate)
	General Equipment Area	3.9×10^{-7}	3.6×10^{-6}	1.5×10^{-5}	1.9×10^{-6} (point estimate)

The Limerick PRA contained areas in which safe shutdown would be lost if fire and/or fire suppression activities failed all components in the fire area. To determine the significance of failing equipment by misdirected fire suppression efforts, the following methodology was used:

(1) Compare the screening value of CDF from the original PRA for a fire area to its final adjusted value.
(2) Determine the method(s) of fire suppression available in the area.
(3) Determine access routes to the area.
(4) Assess the probability of accurate, location-specific detection of a fire within the fire area.
(5) Assess the potential for smoke buildup and visible obscuration of the fire.
(6) Determine what method would be used to discover fire location.

The upper bound (screen value) [1211] for the potential impact of misdirected fire suppression efforts for each area of concern was compared to the PRA estimate below. The reduction factor (Screening Value divided by the PRA Value) shows the reduction in CDF, as a result of successful fire mitigation.

Fire Area	Screening Value	PRA Value	Reduction Factor
13kv Switchgear	2.5×10^{-3}	6.2×10^{-6}	403
Safeguard Access Area	3.8×10^{-3}	6.0×10^{-6}	633
CRD Hydraulic Equipment Area	2.5×10^{-3}	6.4×10^{-6}	390
General Equipment Area	2.8×10^{-3}	1.9×10^{-6}	1473

Because of the large area (approximately 10,000 square feet) and large open equipment hatchways (200 square feet) for mitigating smoke buildup, certain fire areas were screened from further analysis on the basis that fire-fighters would identify the source of the fire through its generation of a smoke plume.

Although Limerick's design features reduced the risk of misdirected fire suppression efforts, two important safety concerns were raised:

(1) Fire and suppression damage (or smoke if equipment is susceptible) confined to a single fire area can lead directly to core damage.

(2) A large reduction factor (up to 1473) is needed to reduce the fire-induced core-melt frequency to a reasonably low level.

In summary, the above sensitivity studies indicate the safety significance of smoke. Through variations in the fire-fighting environment, CDFs ranged from 1.4×10^{-6}/year to 3.8×10^{-5}/year. In addition, the impact of misdirected suppression efforts because of smoke (or the effects of smoke directly if the equipment is susceptible) could be substantial, i.e., a CDF on the order of 10^{-3}/year, if no credit for fire suppression efforts is given. This issue affected all operating and future plants.

Possible Solution

A possible solution was to use the above methodology to search for plant-specific vulnerabilities to smoke and smoke propagation from area to area or unit to unit. This information would then be used to: (1) select effective smoke removal means to preclude potential equipment damage and enhance fire-fighting capability; (2) select appropriate detection and suppression systems in various fire areas (with due consideration of Issue 57); and (3) provide guidance in developing fire response plans.

PRIORITY DETERMINATION

Assumptions

It was assumed[64] that the issue affected 134 operating and future plants with an average remaining life of 28.3 years.

Frequency/Consequence Estimate

The safety significance of this issue was evaluated[64] by PNL as well by SNL.[1415] Comments provided[1365] by NRR were also considered in this evaluation. The discussion presented by NRR pointed to a number of important elements of fire protection at nuclear power plants. Although there were weaknesses in the program and areas of potential improvement, the description and potential merits of fire protection programs at nuclear power plants are based on an ideal implementation of all elements and additional prudent steps taken by licensees beyond those already mandated by regulatory requirements.[1365] However, the objective of this issue was to assess the effectiveness of certain elements of fire protection, namely, smoke control and manual fire-fighting effectiveness. Hence, the insights and data developed as part of NUREG/CR-5088,[1211] as well as operational experience, were taken into account in evaluating this issue.

There were many differences in the models used in the PNL[64] and SNL[1415] analyses. Therefore, the absolute values of CDF were not used, but the changes in CDF resulting from the sensitivity studies were. The analyses and data used by PNL and SNL are summarized below.

The Oconee-3 PRA was the basis for the PNL analysis with three large-fire-initiated accident sequences dominating the risk associated with this issue.[64] However, as pointed out by SNL, certain assumptions made and data used in the PNL analysis should be adjusted to more realistically reflect operational experience, as well as the results of the SNL analysis contained in NUREG/CR-5088.[1211] Based on the PNL approach and taking into account the insights of SNL and cognizant NRC staff, the following adjustments to the PNL assumptions were made to obtain a more realistic assessment of the potential risk associated with smoke control and manual fire-fighting.

The PNL analysis[64] assumed that the base case mean fire suppression time (τ_s) was 14 minutes. Furthermore, it was assumed by PNL that the postulated resolution would reduce τ_s to 11 minutes. PNL also used a value of 6.7 minutes for τ_g, the time required for fire growth and equipment damage based on the Oconee-3 PRA. Based on these assumptions, the following values for CDF due to smoke control and manual fire-fighting and risk were calculated by PNL.

	CDF/RY	Public Risk (man-rem/RY)
Base Case	1.0×10^{-5}	2.3×10^{-1}
Adjusted Case	8.6×10^{-6}	2.0×10^{-1}
Change	1.4×10^{-6}	3.0×10^{-2}

The data developed in NUREG/CR-5088,[1211] however, provided a different set of values for τ_s: the base case mean suppression time (τ_s) was 42 minutes and the solution reduced this value to about 11 minutes. These values were more realistic based on the ranges of τ_s developed by SNL.[1415] Specifically, the following ranges of suppression times were available: (a) 5 to 60 minutes, based on fire protection expert analysis of specific plants; and (b) 2 minutes to 5 hours, based on LER data. For τ_g, a value of 15 minutes was deemed more realistic for the time required for fire growth capable of substantial damage. Based on these assumptions, the following respective values for CDF and risk were calculated:

	CDF/RY	Public Risk (man-rem/RY)
Base Case	4.1×10^{-5}	9.5×10^{-1}
Adjusted Case	1.6×10^{-5}	3.5×10^{-1}
Change	2.5×10^{-5}	6.0×10^{-1}

The potential public risk reduction associated with the issue was (134)(28.3) x (0.6) man-rem or 2,275 man-rem.

Cost Estimate

Industry Cost: Resources for implementation were estimated to be required for two major activities. The first was to search for the potential vulnerabilities identified in this analysis. This search was estimated to require approximately 0.5 man-year or $50,000/plant for reviewing plant drawings and existing fire hazards analyses and a walk-through inspection of potentially susceptible areas. The second main activity was to install improved smoke removal, fire detection, and suppression systems where necessary. A nominal $10,000/plant equipment procurement cost plus an additional 4 man-weeks to install the improved equipment were estimated. This 4 man-weeks labor estimate was increased to account for inefficiencies in nuclear power plant labor productivity resulting from access and handling difficulties, work in radiation zones, congestion and interference (factor of 1.7) and equipment removal (factor of 2.7). At $2,270/man-week, these labor costs were estimated to be approximately $40,000/plant. Thus, the total implementation cost was estimated to be $100,000/plant and $13M for all affected plants.

There were no major new requirements for periodic inspection or maintenance activities that were not already in place. A nominal 1 man-day/RY or $454/RY was added to account for increased operation and maintenance of the improved smoke control, fire detection, and fire suppression systems that were proposed to be installed to replace existing vulnerabilities. The total operation and maintenance cost was estimated to be \$1.7M for all affected plants. Thus, the total industry cost was \$(13 + 1.7)M or \$14.7M.

NRC Cost: NRC development costs were estimated to be incurred for development of fire protection program guidance in the area of smoke control and for preparation and issuance of a generic letter that would transmit the new guidance to all licensees. A nominal 2 man-years or \$200,000 were estimated for development of the fire protection guidance. The NRC labor needed to prepare and issue a generic letter was estimated to be approximately 4 man-weeks or \$10,000.[961] Thus, the total cost associated with development of a solution was estimated to be \$210,000.

It was estimated that it would require 5 man-weeks/plant to review and approve implementation of the enhanced smoke control program and improved equipment and 7 man-weeks/plant to prepare a safety evaluation.[961] At \$2,270/man-week, implementation costs were estimated to be \$3.65M for all affected plants.

Review of licensee operation and maintenance was estimated to require 1 man-day/RY or \$454/RY. For the 134 affected plants, this cost was \$1.7M. Thus, the total NRC cost was \$(0.21 + 3.65 + 1.7)M or \$5.56M.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be \$(14.7 + 5.56)M or approximately \$20.26M.

Value/Impact Assessment

Based on a potential public risk reduction of 2,275 man-rem and an estimated cost of \$20.26M for a possible solution, the value/impact score was given by:

$$S = \frac{2{,}275 \text{ man-rem}}{\$20.26\text{M}}$$

$$= 112 \text{ man-rem/\$M}$$

CONCLUSION

Based on the above results, the issue fell in the high priority range, on the basis of CDF, and in the medium priority range, on the basis of risk. However, the safety significance was likely to vary greatly from plant to plant and it appeared unlikely that any cost-effective generic resolution could be identified. Thus, it was believed that plant-specific reviews would most likely be required. Such reviews were already required as part of the IPEEE Program. However, the staff had little or no guidance for the review and acceptance of IPEEE submittals in this area. Therefore, the issue was classified[1745] as a Licensing Issue in August 1992 to allow the staff to develop guidance to improve its effectiveness in the review of licensee IPEEE submittals. The issue was later closed out when the staff completed the review guidance and incorporated it into the overall IPEEE review guidance.[1746]

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961. NUREG/CR-4627, "Generic Cost Estimates," U.S. Nuclear Regulatory Commission, June 1986, (Rev. 1) February 1989, (Rev. 2) February 1992.

1174. NUREG-1251, "Implications of the Accident at Chernobyl for Safety Regulation of Commercial Nuclear Power Plants in the United States," U.S. Nuclear Regulatory Commission, (Vols. I and II) April 1989.

1211. NUREG/CR-5088, "Fire Risk Scoping Study: Investigation of Nuclear Power Plant Fire Risk, Including Previously Unaddressed Issues," U.S. Nuclear Regulatory Commission, January 1989.

1320. SECY-89-170, "Fire Risk Scoping Study: Summary of Results and Proposed Staff Actions," June 7, 1989.

1365. Memorandum for Z. Rosztoczy from S. Bajwa, "Generic Issue 148: Smoke Control and Manual Fire Fighting Effectiveness; Generic Issue 149: Adequacy of Fire Barriers," April 3, 1991.

1407. NUREG/CR-4681, "Enclosure Environment Characterization Testing for the Base Line Validation of Computer Fire Simulation Codes," U.S. Nuclear Regulatory Commission, March 1987.

1415. Letter to D. Basdekas (NRC) from J. Lambright (SNL), "Generic Issue 148, 'Smoke Control and Manual Fire Fighting Effectiveness,'" March 4, 1992.

1745. Memorandum for W. Minners from E. Beckjord, "Generic Issue No. 148, 'Smoke Control and Manual Fire-Fighting Effectiveness,'" August 26, 1992.

1746. Memorandum to A. Thadani from T. King, "Staff Review Guidance for Generic Safety Issue (GSI) 148, 'Smoke Control and Manual Fire-Fighting Effectiveness,'" July 22, 1999.

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 were 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 were 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.I 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 seismically-initiated 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 modeled 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 125V 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

<u>Peach Bottom-2</u>: 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-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-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 2×10^{-7}/RY in CDF for Unit 1 and 2, respectively.

Surry-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 7.2×10^{-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-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 7.2×10^{-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 5.8×10^{-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-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 6.12×10^{-3}, which is based on a one-year surveillance test or maintenance interval and a failure rate of 1.4×10^{-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 an estimated cost of \$1M/reactor for a possible solution, the value/impact score was given by:

$$S = \frac{27 \text{ man-rem/reactor}}{\$1\text{M/reactor}}$$

$$= 27 \text{ man-rem/\$M}$$

PWRs: Based on a potential public risk reduction of 10 man-rem/reactor and an estimated cost of \$1M/reactor for a possible solution, the value/impact score was given by;

$$S = \frac{10 \text{ man-rem/reactor}}{\$1\text{M/reactor}}$$

$$= 10 \text{ man-rem/\$M}$$

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 modeling 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 March 1993. Consideration of a 20-year license renewal period did not change the priority of the issue.[1564] Further prioritization, using the conversion factor of \$2,000/man-rem approved by the

Commission in September 1995, resulted in an impact/value ratio (R) of $37,037/man-rem which placed the issue in the DROP category.

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

DESCRIPTION

Historical Background

In 1967, the AEC published draft GDCs for comment and interim use and, until 1972, the staff's implementation of the GDCs required consideration of pipe break effects inside containment. However, due to the lack of documented review criteria, AEC staff positions continued to evolve. Review uniformity was finally developed in the early 1970s, initiated by a November 9, 1972, note from L. Rogers to R. Fraley, in which a Draft Safety Guide entitled "Protection Against Pipe Whip Inside Containment" was proposed. This Draft Guide contained some of the first documented deterministic criteria that the staff had used for several years (to varying degrees) as guidelines for selecting the locations and orientations of postulated pipe breaks inside containment, and for identifying the measures that should be taken to protect safety-related systems and equipment from the dynamic effects of such breaks. Prior to use of these deterministic criteria, the staff used non-deterministic guidelines on a plant-specific basis. The Draft Safety Guide was subsequently revised and issued in May 1973 as Regulatory Guide 1.46[18] for implementation on a forward-fit basis only.

The AEC issued two generic letters to all licensees and CP or OL applicants regarding pipe break effects outside containment in December 1972[139] and July 1973. These letters, known as the "Giambusso" and "O'Leary" letters, respectively, extended pipe break concerns to locations outside containment, and provided deterministic criteria for break postulation and evaluation of the dynamic effects of postulated breaks. The letters requested all recipients to submit a report to the staff summarizing each plant-specific analysis of the issue. All operating reactor licensees and license applicants submitted the requested analyses in separate correspondence or updated the SARs for their proposed plants to include the analysis. The staff reviewed the submitted analyses and prepared safety evaluations for all plants. In November 1975, the staff published SRP[11] Sections 3.6.1 and 3.6.2 that slightly revised the two generic letters discussed above. Thus, after 1975, the specific structural and environmental effects of pipe whip, jet impingement, flooding, etc., on systems and components relied on for safe reactor shutdown were considered.

As stated above, the AEC/NRC has provided requirements to the industry regarding pipe breaks outside of containment through the issuance of the Giambusso and O'Leary generic letters. Since these requirements are applicable to all the affected plants, pipe breaks outside of containment were judged to be a compliance issue and were not considered in this analysis. Compliance matters are dealt with promptly and do not await the generic issue resolution process. Therefore, the issue of pipe breaks outside of containment for the 41 affected plants was brought to the attention of NRR by separate correspondence.[1761] The remainder of this evaluation only addressed pipe breaks inside containment.

As a part of its plant-specific reviews between 1975 and 1981, the staff used the guidelines in Regulatory Guide 1.46[18] for postulated pipe breaks inside containment, and SRP[11] Sections 3.6.1 and 3.6.2 for outside containment. In July 1981, SRP[11] Sections 3.6.1 and 3.6.2 were revised to be applicable to both outside and inside containment, thus eliminating the need for further use of Regulatory Guide 1.46,[18] which was subsequently withdrawn.

Between the period 1983-1987, the general issue of pipe breaks inside and outside containment was revisited in the SEP. The objective of the SEP was to determine to what extent the earliest 10 plants (i.e., SEP-II) met the licensing criteria in existence at that time. This objective was later interpreted to ensure that the SEP also provided safety assessments adequate for conversion of provisional operating licenses (POLs) to full-term operating licenses (FTOLs). As a result of these reviews, plants were required to perform engineering evaluations, TS or procedural changes, and physical modifications both inside and outside containment. Regarding inside containment modifications: of the two SEP-II plants evaluated in this analysis (one BWR and one PWR), the BWR was required to modify four piping containment penetrations and the PWR was required to modify steam generator blowdown piping supports. This indicates there was a wide spectrum of implementation associated with the original reviews of these early plants for pipe breaks inside and outside containment.

As with the above-described evolution of uniform pipe break criteria, electrical systems design criteria were also in a state of development. Prior to 1974, electrical system designs were generally reviewed in accordance with the guidelines provided in IEEE-279; however, significant variations in interpretations of that document resulted in substantial design differences in plants. Specifically, true physical separation of wiring to redundant components was not necessarily accomplished. In 1974, Regulatory Guide 1.75 was published, clarifying the requirements.

An earlier evaluation of this issue resulted in a medium-priority ranking (see Appendix C) with the finding that the scope could be limited to pipe breaks inside containment, since the NRC had already provided requirements regarding outside containment pipe breaks to the industry through the issuance of the Giambusso and O'Leary generic letters. However, the uncertainty in the analysis was much wider than desired for a definitive priority ranking. Thus, the issue appeared to warrant additional analysis to enhance the prioritization. In July 1994, a contract was awarded to INEEL to:

(1) Review pipe failure rate data, pipe break methodologies, and related publications to determine recommended pipe failure rates (initiating events) applicable to the affected SEP-III plants.

(2) Review updated FSARs and related SERs for SEP-II, SEP-III, and for representative non-SEP plants to identify and prioritize potential safety concerns (i.e., accident sequences). Several plant visits and walkdowns were included as part of this review.

(3) Estimate changes to core damage frequencies for accident sequences that are determined to be of high or medium priority.

(4) Identify potential corrective actions and their estimated costs.

The evaluation that follows was based on the results of the INEEL research.

Safety Significance

GDC 4 is the primary regulatory requirement of concern. It requires, in part, that structures, systems and components important to safety be appropriately protected against the environmental and dynamic effects that may result from equipment failures, including the effects of pipe whipping and discharging fluids. Several possible scenarios for plants that do not have adequate protection against pipe whip were identified as a result of the research performed in support of the enhanced prioritization. Related regulatory criteria include common cause failures, protection system independence, and the single failure criterion.

Possible Solution

Issue generic letters to the affected plants requesting that they perform plant-specific reviews and walkdowns, identify vulnerable pipe break locations, and inform the NRC of proposed corrective actions.

PRIORITY DETERMINATION

Numerous scenarios of potential concern were evaluated. The following were considered important enough to be specifically identified for future consideration. All estimated frequencies and probabilities are mean values.

Frequency Estimate

BWRs

Case 1: Failure of Main Steam or Feedwater Piping Resulting in Pipe Whip and Containment Impact/Failure, with Resultant Failure of All Safety Injection Systems

This event (INEEL BWR Event 1) involved a BWR with a Mark I steel containment; 15 of the 16 affected BWRs were of this design. A DEGB of an unprotected (i.e., no pipe whip restraint or containment liner impact absorber) large reactor coolant recirculation pipe inside containment and near the containment liner might result in puncturing of the liner. The resulting unisolable LOCA steam environment would be introduced into the secondary containment building, possibly disabling the ECCS equipment located there. This scenario would greatly increase the probability of core damage and potential offsite doses.

All of the affected BWRs were more than 10 years old and most used Type 304SS in the primary system piping, a material that was susceptible to IGSCC degradation. It should be noted that piping of this material did not qualify for the extremely low rupture probability (leak-before-break) provision of GDC 4. From NUREG-1150,[1081] the recirculation loop DEGB frequency for this material was estimated to be 10^{-4}/RY. The fraction of BWR primary piping inside containment that was either main steam or feedwater was estimated to be 0.4. The fraction of main steam or feedwater piping that can impact the containment metal shell was estimated to be 0.25.

The research performed indicated that there was considerable variation among the affected plants regarding the amount of pipe whip protection provided and the proximity of high energy lines to potential targets of concern, including redundant trains (see Other Considerations). It was assumed that the probability of a main steam or feedwater broken pipe rupturing the containment metal shell was 0.25.

The postulated event may also cause a common mode failure of the ECCS system since much of this equipment was located within the secondary containment and will be exposed to a harsh environment beyond its design basis, or that the ECCS piping will fail due to overpressurization of the containment annulus. In most of the affected plants, the ECCS is located in four different quadrants outside the suppression pool (torus). On the other hand, as stated above, redundant electrical power systems and initiating circuitry may not be physically separated in the older plants. Also, if the ECCS operates initially, the ECCS equipment rooms may not be fully protected from internal flooding as the water from the suppression pool flows out the broken pipe into the secondary containment. Based on these considerations, the mean probability of loss of ECCS function was assumed to be 0.8. Based on the above assumptions, the mean value of change in CDF was 2×10^{-6}/RY.

From WASH-1400,[16] the nearest scenario to that described above was the large LOCA BWR-3 release category involving a large LOCA and subsequent containment failure. However, in the WASH-1400[16] case, the containment failure results from overpressurization, not from pipe whip. Three of the four specific BWR-3 large LOCA accident sequences have an incidence frequency of 10^{-7}/RY, and the remaining one is 10^{-6}/RY; 10^{-7}/RY was chosen as the base case for this analysis.

Case 2: Failure of Recirculation Piping Resulting in Pipe Whip and Containment Impact/Failure, With Resultant Failure of All Emergency Core Cooling Systems

This event (INEEL BWR Event 9) was similar to Case 1 but involved the recirculation system piping. From NUREG-1150,[1081] the recirculation loop DEGB mean frequency for this material was estimated to be 10^{-4}/RY. The fraction of BWR primary piping inside containment that is recirculation piping was estimated to be 0.2. The fraction of recirculation piping that can impact the containment metal shell was estimated to be 0.5. It was estimated that the mean probability of a recirculation system broken pipe rupturing the containment metal shell was 0.5. The mean probability of eventual failure of all ECCS by the same modes described for Case 1 was estimated to be 0.8. Based on the above assumptions, the mean value of change in CDF was 4×10^{-6}/RY.

Case 3: Failure of RHR Piping Resulting in Pipe Whip and Containment Impact/Failure, With Resultant Failure of All Emergency Core Cooling Systems

This event (INEEL BWR Event 12) was similar to Cases 1 and 2 but involved the RHR System piping. From NUREG-1150,[1081] the RHR DEGB frequency for this material was estimated to be 10^{-4}/RY. The fraction of BWR primary piping inside containment that is RHR piping was estimated to be 0.1. The fraction of RHR piping that can impact the containment metal shell was estimated to be 0.5. The mean probability of a recirculation system broken pipe rupturing the containment metal shell was 0.1. The mean probability of eventual failure of all ECCS by the same modes described for Cases 1 and 2 was estimated to be 0.8. Based on the above assumptions, the mean value of change in CDF/RY was 4×10^{-7}/RY.

Case 4: Failure of Recirculation Piping Resulting in Pipe Whip or Jet Impingement on Control Rod Drive Bundles, Causing Failure by Crimping of Enough Insert/Withdraw Lines to Result in Failure to Scram the Reactor

This case corresponded to INEEL BWR Event 5. From NUREG-1150,[1081] the recirculation loop DEGB frequency for this material was estimated to be 10^{-4}/RY. The fraction of BWR primary piping inside containment that is recirculation piping was estimated to be 0.2. The fraction of recirculation piping that can impact or impinge on the CRD lines was estimated to be 0.25. It was estimated that the mean probability of a broken RHR pipe crimping enough CRD lines to prevent a scram (about 5 to 10 adjacent lines) was 1. Based on the above assumptions, the mean value of change in CDF was estimated to be 5×10^{-6}/RY.

Case 5: Failure of RHR Piping Resulting in Pipe Whip or Jet Impingement on Control Rod Drive Bundles, Causing Failure by Crimping of Enough Insert/Withdraw Lines to Result in Failure to Scram the Reactor

This event (INEEL BWR Event 10) was similar to Case 3 but involved the RHR system piping. The research performed indicated that there was considerable variation among the affected plants regarding the amount of pipe whip protection provided and the proximity of high energy lines to potential targets of concern. Walkdowns showed that, in at least one case, a large "unisolable from the RCS" RHR line was routed directly between the two banks of CRD bundles. An RHR pipe break in this vicinity would impinge and/or impact on both banks simultaneously.

From NUREG-1150,[1081] the RHR DEGB frequency for this material was estimated to be 10^{-4}/RY. The fraction of BWR primary piping inside containment that consitutes RHR piping was estimated to be 0.1. The fraction of RHR piping that can impact or impinge on the CRD lines was estimated to be 0.25. It was estimated that the mean probability of a broken RHR pipe crimping enough CRD lines to prevent a scram (about 5 to 10 adjacent lines) was 1. Based on the above assumptions, the mean value of change in CDF was 2.5×10^{-6}/RY.

Case 6: Failure of High Energy Piping Resulting in Pipe Whip or Jet Impingement on Reactor Protection or Instrumentation & Control Electrical, Hydraulic or Pneumatic Lines, or Components and Eventually Resulting in Failure of Mitigation Systems and Core Damage

This case corresponded to INEEL BWR Event 14. From NUREG-1150,[1081] the large LOCA frequency is 10^{-4}/RY. All high energy piping inside containment was considered. The fraction of high energy piping that can impact or impinge on these lines or components was estimated to be

0.5. The mean probability of a broken high energy line failing some of these lines or components to the extent that core damage results was estimated to be 0.75. Based on the above assumptions, the mean value of change in CDF was 3.8 x 10^{-5}/RY.

Case 7: Failure of High Energy Piping Resulting in Pipe Whip Impact on Reactor Building Component Cooling Water (RBCCW) System to the Extent That the RBCCW Pressure Boundary is Broken, Potentially Opening a Path to Outside Containment if Containment Isolation Fails to Occur; Also Possible Loss of RBCCW Outside Containment for Mitigation

This case corresponded to INEEL BWR Event 16. From NUREG-1150,[1081] the large LOCA frequency was 10^{-4}/RY. All high energy piping inside containment was considered. The fraction of high energy piping that can impact the RBCCW system was estimated to be 0.1. The probability of an HELB broken pipe rupturing the RBCCW system was 0.5. The probability of failure to close of containment isolation check valve was 10^{-3}; the probability of failure to close of a containment isolation MOV was 3 x 10^{-3}. These scenarios had a combined total probability of 4 x 10^{-3}. Since the RBCCW surge tank in the secondary containment is vented to atmosphere and has a relatively small volume, it was assumed that its water inventory will drain quickly; for this reason, the mean probability of opening a path to atmosphere outside containment was 1. Once this scenario proceeds to this point, the RBCCW system in the secondary containment will become unavailable, including the RHR heat exchanger; therefore, the probability of losing the RBCCW function outside containment to the extent that core damage occurs was 1. Based on the above assumptions, the mean value of change in CDF was estimated to be 2 x 10^{-8}/RY.

The total change in CDF for the above 7 BWR cases was estimated to be 5.2 x 10^{-5}/RY. For all 16 affected BWRs, ΔCDF was 8.3 x 10^{-4}/RY.

PWRs

Case 1: Failure of Non-Leak-Before-Break Reactor Coolant System, Feedwater, or Main Steam Piping Resulting in Pipe Whip or Jet Impingement on Reactor Protection or Instrumentation & Control Electrical, Hydraulic or Pneumatic Lines or Components and Eventually Resulting in Failure of Mitigation Systems and Core Damage

This case corresponded to INEEL PWR Event 9. From NUREG-1150,[1081] the HELB frequency in the above-listed systems was 1.5 x 10^{-3}/RY. All of the listed high energy piping inside containment was considered. The fraction of high energy piping that can impact or impinge on these lines or components was estimated to be 0.1. The mean probability of a broken high energy line failing some of these lines or components to the extent that core damage results was estimated to be 0.5. Based on the above assumptions, the mean value of change in CDF was 7.5 x 10^{-5}/RY.

Case 2: Failure of Main Steam or Feedwater Piping Resulting in Pipe Whip and Containment Impact/Failure, with Resultant Failure of All Emergency Core Cooling Systems

This case corresponded to INEEL PWR Event 16. From NUREG-1150,[1081] the DEGB frequency in feedwater piping was estimated to be 4 x 10^{-4}/RY; for main steam piping, it was estimated to be 10^{-4} /RY. The fraction of feedwater piping that can impact the containment shell was estimated to be 0.1. The fraction of main steam piping was also estimated to be 0.1; this fraction remained 0.1. The mean probability of a feedwater or main steam system broken pipe rupturing the containment metal shell was 0.5. The mean probability of additional I&C or ECCS systems failures to the extent that core damage results was estimated to be 4.8×10^{-5} for the case involving feedwater piping breaks, and 9.8×10^{-5} for the case involving main steam piping breaks. Based on the above assumptions, the mean value of change in CDF was 1.4×10^{-9}/RY.

Case 3: Failure of Main Steam or Feedwater Piping Resulting in Pipe Whip Impact on CCW System to the Extent That the CCW Pressure Boundary is Broken, Potentially Opening a Path to Outside Containment if Containment Isolation Fails to Occur; Also Possible Loss of CCW Outside Containment for Mitigation

This case corresponded to INEEL PWR Event 17. From NUREG-1150,[1081] the DEGB frequency in feedwater piping was estimated to be 4×10^{-4}/RY; for main steam piping, it was estimated to be 10^{-4}/RY; this combined for a total frequency of 5×10^{-4}/RY. The fraction of feedwater piping that can impact the CCW system was estimated to be 0.1; the fraction of main steam piping was also estimated to be 0.1; this fraction remained 0.1. The probability of a feedwater or main steam system broken pipe rupturing the CCW system was 0.5. The probability of failure to close of containment isolation check valve was 10^{-3}; the probability of failure to close of a containment isolation MOV was 3×10^{-3}; this combined for a total probability of 4×10^{-3}. Since the CCW surge tank is in the auxiliary building near mitigation equipment, is vented to atmosphere, and has a relatively small volume, it was assumed that its water inventory will drain quickly. For this reason, the mean probability of opening a path to atmosphere outside containment was 1. Once this scenario proceeds to this point, the CCW system outside containment will become unavailable, including the RHR heat exchanger. Therefore, the probability of losing the CCW function outside containment, to the extent that core damage occurs, is 1. Based on the above assumptions, the mean value of change in CDF was 10^{-7} /RY.

The total change in CDF for the above three PWR cases was 7.5×10^{-5}/RY. For all 25 affected PWRs, the ΔCDF was estimated to be 1.9×10^{-3}/RY.

Consequence Estimate

TABLE 3.156-1
BWR Offsite Dose Table

NUREG/CR-6395 Event Number	ΔCDF (Event/RY)	WASH-1400[16] Release Category	WASH-1400[16] Offsite Dose (Man-rem/Event)	Offsite Dose (Man-rem/RY)
Event 1	2.0×10^{-6}	BWR-3	5.1×10^{6}	10.2
Event 5	5.0×10^{-6}	BWR-4	6.1×10^{5}	3.1
Event 9	4.0×10^{-6}	BWR-3	5.1×10^{6}	20.4
Event 10	2.5×10^{-6}	BWR-4	6.1×10^{5}	1.5
Event 12	4.0×10^{-7}	BWR-3	5.1×10^{6}	2.0
Event 14	3.8×10^{-5}	BWR-4	6.1×10^{5}	23.2
Event 16	2.0×10^{-8}	BWR-3	5.1×10^{6}	0.1
TOTAL:				**60.5**

For the 16 affected BWRs with an average remaining life of 17 years, the estimated change in offsite dose was (60.5 man-rem/RY)(16 reactors)(17years) or 16,464 man-rem.

TABLE 3.156-2
PWR Offsite Dose Table

NUREG/CR-6395 Event Number	ΔCDF (Event/RY)	WASH-1400[16] Release Category	WASH-1400[16] Offsite Dose (man-rem/event)	Offsite Dose (man-rem/RY)
Event 9	7.5×10^{-5}	PWR-6	1.5×10^{5}	11.3
Event 16	1.4×10^{-9}	PWR-4	2.7×10^{6}	0.004
Event 17	1.0×10^{-7}	PWR-4	2.7×10^{6}	0.3
TOTAL:				**11.6**

For the 25 affected PWRs with an average remaining life of 17 years, the estimated change in offsite dose was (11.6 man-rem/RY)(25 reactors)(17 years) or 4,925 man-rem. Thus, the estimated total offsite dose for the 41 affected plants was (16,464 + 4,925) man-rem or 21,389 man-rem.

Cost Estimate

Industry Cost: Implementation of the possible solution was assumed to require the performance of engineering analyses inside containment, perform system walkdowns, and provide a report to the NRC. Ultimately, it was expected that operating procedures and/or TS will be modified, inservice inspections will be enhanced, or physical modifications will be done either to piping (probably addition of pipe whip restraints or jet shields) or to the inside containment leakage detection system. It is expected that the cost to each plant will be $1M. Therefore, for the 41 affected plants (16 BWRs and 25 PWRs), the total implementation cost was estimated to be $41M. This estimate was based on the presumption that the level of effort at the affected plants would be similar to that which resulted for this issue during the SEP program review of the 10 earliest SEP plants.

NRC Cost: Development and implementation of a resolution was estimated to cost $1M, primarily involving review of industry submittals and possible proposed changes to hardware.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $42M.

Impact/Value Assessment

Based on a potential public risk reduction of 21,389 man-rem and an estimated cost of $42M for a possible solution, the impact/value ratio was given by:

$$R = \frac{\$42M}{21{,}389 \text{ man-rem}}$$

$$= \$1{,}960/\text{man-rem}$$

Other Considerations

(1) The updated SAR for an SEP-III BWR (i.e., one of the 41 plants potentially affected by this issue) stated that, in the event of a DEGB, the broken pipe would strike the Mark I Containment and deform it significantly. However, another BWR of about the same vintage is known to have been required to add energy absorbing structures to protect the Mark I Containment from pipe whip, prior to receipt of an operating license. Therefore, it appeared that there was considerable variation among the affected plants regarding the amount of pipe whip protection provided.

(2) Pipe breaks have actually occurred in the industry. Examples include a Surry feedwater line break, a WNP-2 Fire System valve structural pressure boundary failure, and a Ft. Calhoun 12" steam line break.

(3) Some suspect configurations were observed in the SEP-III walkdown plants, e.g., at one BWR a very close proximity exists between a large RHR (unisolable from RCS) pipe and both banks of the CRD piping, and at one PWR it appeared that a large volume of piping penetrated the containment near where a large amount of electrical wiring also penetrated the containment. This demonstrated that, even through modest efforts (i.e., sampling walkdowns of a sampling of plants), configurations of potential concern have been identified.

(4) Readily available plant documentation provides very little insights regarding actual proximity of high energy piping and potential targets or concern. The potential lack of adequate separation of redundant system targets (e.g., I&C electrical wiring) is also a concern.

(5) Uncertainty remains a significant factor because of the large scope of this issue. This is because of the large number and types of plants, and significant differences in the specific as-built details applicable to this issue.

(6) Many of the affected plants are either currently applying for life extension or are expected to in the near future. Most of the lead life extension applications will be from the affected plants for many years to come.

(7) Although there is a large apparent disparity between the BWR and PWR cases evaluated, it must be remembered that much of the background of this issue was based on sampling walkdowns, i.e., only selected portions of selected plants were available for these walkdowns. Therefore, it is important to treat the BWR and PWR evaluations equally during the next phase of the evaluation. Also, some of the listed scenarios seem to have low probabilities but potentially high consequences. They should be further evaluated.

(8) Assuming a life extension of 20 years for the 31 affected plants, the public risk reduction would be 35,824 man-rem and 10,725 man-rem for BWRs and PWRs, respectively. This would produce an impact/value ratio of $900/man-rem.

CONCLUSION

Several potential accident scenarios were identified; 7 for BWRs and 3 for PWRs. Mean values for core damage were estimated for each and the cumulative effect of each group was also estimated. The total change in CDF was 8.3×10^{-4}/year for the 16 affected BWRs and 7.5×10^{-5}/RY for the

3 PWR cases. This would give the issue a medium/high priority ranking (see Figure 2 of NUREG-0933). For all 25 affected PWRs, ΔCDF/Year was 1.9×10^{-3}, which would also give the issue a high/medium priority ranking. Further evaluations which included estimates of offsite doses and costs for potential solutions showed that the issue has a HIGH priority ranking.[399]

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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,[1741] and AEOD/C603[1742] (which was forwarded[1743] to the Commission). 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 safety valves 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 the SWS at BWRs. The use of power-operated valves in safety systems was sufficiently widespread to raise concerns similar to those on MOVs addressed in the implementation of Generic Letter No. 89-10.[1217] Therefore, this issue 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, it was believed that 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-1, Oconee-3, and Sequoyah-1 PRAs were used to model PWR AOVs and SOVs in SARA 4.0.[1456] The Grand Gulf-1 and Peach Bottom-2 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 x 10^{-3} or 8.7 x 10^{-3} was given compared to a NUREG-1150[1081] value of 10^{-3}; 8.7 x 10^{-3} was chosen for conservatism. An AEOD analysis of NPRDS data for AOVs determined a demand failure probability of 1.1 x 10^{-2} for AOVs in risk significant systems and 4.2 x 10^{-2} for all AOVs, compared to a NUREG-1150[1081] value of 10^{-3} to 2 x 10^{-3}. Because of the ambiguity in the modifier "risk significant," 4.2 x 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-3 and Surry-1 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-1 and Peach Bottom-2 results were chosen to be representative of all plants. Although the Oconee-3 and Surry-1 results were negligible and the Grand Gulf-1 results were much less than that of Peach Bottom-2, 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 x 10^{-5}/RY and and 1.202 x 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-1 and Peach Bottom-2 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

Reactor Type	PRA	ΔCore-Melt Frequency/RY
PWR	Sequoyah-1	1.236×10^{-5}
PWR	Oconee-3	-
PWR	Surry-1	-
BWR	Peach Bottom-2	1.202×10^{-5}
BWR	Grand Gulf-1	1.606×10^{-7}

TABLE 3.158-2
PWR and BWR Results for Changes in Core-Melt Frequency and Public Risk

Reactor Type	ΔCore-Melt Frequency/RY	ΔPublic 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 NRC and industry 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[1739] in January 1994. In accordance with an RES evaluation,[1564] the impact of a license renewal period of 20 years was to be considered in the resolution of the issue.

In resolving the issue, the staff concluded that existing regulations provided an adequate framework for any needed regulatory action. NRR committed to undertake efforts in conjunction with the industry to ensure that existing requirements for valve operability under design basis conditions will be met. Thus, the issue was RESOLVED with no new or revised requirements[1744] and licensees were informed of the staff's conclusion in NRC Regulatory Issue Summary 2000-03.[1768]

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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 relief valve 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 relief valves 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 relief valves 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 a relief valve 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 relief valve unreliability for various systems throughout a plant with spring-actuated relief valves. From these data, a best estimate probability of the relief valve 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 relief valve 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 relief valves in SARA 4.0,[1456] the Grand Gulf PRA[1318] was primarily used to model BWR relief valves, and the Peach Bottom PRA[1318] was used to support the Grand Gulf results.

Because the Surry PRA did not include relief valves in every system, modifications to the PRA were required to model their effects on a particular system. For those systems where relief valves were included with a component in a single train whose unavailability could fail the entire system, the failure probability of the relief valve was added to the component's failure probability. On the other hand, for those systems where relief valves were included with components in two trains where common mode failure could occur, the failure probability of the relief valve 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 relief valve reliability) and $\boldsymbol{\beta}$ (the beta factor for the relief valve and component) were given by $\mathbf{P} = (\mathbf{P_c} + \mathbf{P_v})$ and $\boldsymbol{\beta} = [(\boldsymbol{\beta_c}\mathbf{P_c} + \boldsymbol{\beta_v}\mathbf{P_v})/(\mathbf{P_c} + \mathbf{P_v})]$, where $\boldsymbol{\beta_c}$ and $\boldsymbol{\beta_v}$ were the beta factors and $\mathbf{P_c}$ and $\mathbf{P_v}$ were the failure probabilities for the component and relief valve, respectively. In this analysis, a value of 7×10^{-2} was used for $\boldsymbol{\beta_v}$ which was obtained from the beta factor for an SRV in the PRA. The values of $\boldsymbol{\beta_c}$ and $\mathbf{P_c}$ were obtained from the applicable component in the PRA. Using the above equations, the values of **P** and $\boldsymbol{\beta}$ 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 relief valves 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 2×10^4 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 systems with relief valves 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.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $(8.7 + 2.6)M or $11.3M.

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}
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}
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

Reactor Type	ΔCore-Melt Frequency/RY for Various Valve Failure Probabilities			ΔPublic Risk (man-rem/RY) for Various Valve Failure Probabilities		
	0.005	**0.001**	**0.05**	**0.005**	**0.001**	**0.05**
PWR	2.6×10^{-5}	5.3×10^{-6}	2.9×10^{-4}	73	15	770
BWR	2.0×10^{-6}	4.0×10^{-7}	2.2×10^{-5}	5.8	1.2	62

Impact/Value Assessment

Based on a potential public risk reduction of 10^5 man-rem and an estimated cost of \$11M for a possible solution, 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.[1732] In accordance with an RES evaluation,[1564] the impact of a license renewal period of 20 years was to be considered in the resolution of the issue.

In resolving the issue, the staff performed an analysis of an SRV failing its train and found the resultant CDF increase to be negligible. The staff also determined that additional testing of SRVs was included in the 1986 Edition of ASME Section XI and was later endorsed by the NRC in the 1992 revision of 10 CFR 50.55a. Thus, the issue was RESOLVED with no additional requirements[1733] and licensees were informed of the staff's conclusion in NRC Regulatory Issue Summary 2000-05.[1769]

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ISSUE 169: BWR MSIV COMMON MODE FAILURE DUE TO LOSS OF ACCUMULATOR PRESSURE

DESCRIPTION

Historical Background

This issue was identified[1684] by NRR following a request from Region I to review GE SIL 477 which identified the possibility of early containment bypass in a BWR, if any one of the MSIVs inside containment should fail to close, or fail to stay closed, during events that require main steam isolation. This failure could result from one or both of the following common causes: (1) valve operator spring pressure alone may not be adequate to close the MSIV; or (2) pneumatic accumulator pressure may not be adequately monitored and alarmed. Following a preliminary review of the safety concern, RES determined[1685] that the installation of a pressure alarm switch that would monitor nitrogen pressure at the MSIVs inside containment had the potential to be a cost-beneficial safety enhancement.

Each steam line penetrating the containment of a BWR is fitted with two MSIVs, one inside containment (inboard) and one outside containment (outboard), which are designed to perform the following safety functions:

(1) Prevent damage to the fuel barrier by limiting the loss of reactor coolant water in the event of a major leak from steam piping located outside the primary containment;

(2) Limit the release of radioactive materials by closing the nuclear system process barrier in the event of a gross release of radioactive materials from the reactor fuel to the reactor coolant water and steam;

(3) Limit the release of radioactive materials by closing the primary containment barrier in the event of a major leak from the nuclear system inside the primary containment.

Each MSIV is operated by a combination air and spring actuation system. Helical springs surrounding the spring guide shafts close the valve if air pressure is not available. Each inboard MSIV is supplied with air from the containment drywell pneumatic or nitrogen system. These air supplies are supplied through check valves into accumulator tanks which provide a pneumatic reserve for the closing of each valve.

Safety Significance

In BWRs, reactor steam is delivered directly to the turbine and other equipment located outside the containment. Radioactive materials in the steam can be released to the environment via process openings in the main steam system or via accidental openings. A major rupture in the steam system could drain water from the reactor core more quickly than it can be replaced by feedwater. This issue is applicable to all BWRs.

Possible Solution

A possible solution to the issue was assumed to be additional instrumentation and alarms to provide improved monitoring of the pressure in the air accumulators to help ensure the availability of adequate air supplies to the MSIVs. Alarms in the control room would annunciate if the accumulator pressure on an MSIV were to fall below a pre-set level. This action would subsequently be expected to reduce the common cause failure probability that MSIVs would fail to close on demand.

PRIORITY DETERMINATION

Assumptions

It was assumed that all 37 operating BWRs do not have a monitoring and alarm system and would be affected by the issue. The average remaining life of these plants was assumed to be 22 years.

Frequency Estimate

There are two types of conditions at a BWR in which the failure of an inboard MSIV to close or remain closed could lead to core damage with containment bypass: (1) the associated outboard MSIV closes, but the short length of piping connecting the two valves ruptures outside of containment; (2) the associated outboard MSIV fails to close or remain closed following the rupture of downstream main steam piping.

In an evaluation[1686] of this issue by Science and Engineering Associates (SEA), the base case CDF (F) was estimated as follows:

$$\bar{F} = F_1 P_{1a} P_{1b} + F_2 P_{2a} P_{2b}$$

where,

	F_1	=	frequency of a break between the containment wall and the outboard MSIV
	P_{1a}	=	probability of a failure on demand of the spring on the adjacent inboard MSIV
	P_{1b}	=	probability that design pressure is not available in the inboard accumulator
	F_2	=	frequency of a main steam line LOCA outside containment
	P_{2a}	=	probability of failure on demand of the springs in both the inboard and outboard MSIVs on the broken steam line
	P_{2b}	=	probability of unavailability of design pressure in both accumulators on the broken steam line

From PRAs in NUREG-4550, a main steam line break outside of containment is equivalent to a large LOCA. As an internal event, the frequency of a large LOCA was estimated to be 10^{-4} /RY. With the inclusion of external events in the PRA, the additional LOCA frequency from seismic events was estimated to be 1.9×10^{-5}/RY. Thus, the frequency of a main steam line LOCA outside containment, F_2, is $(10^{-4} + 1.9 \times 10^{-5})$/RY or approximately 1.2×10^{-4}/RY. Based on the approximate ratio of welds, 1:60, the frequency of a break between the containment wall and an outboard MSIV, F_1, was estimated to be $(1/60)(1.2 \times 10^{-4}/\text{RY})$ or (2×10^{-6})/RY.

The probability of a failure on demand of the spring on the adjacent inboard MSIV, P_{1a}, was the same as the probability of failure on demand of the springs in both the inboard and outboard MSIVs on the broken steam line, P_{2a}. Based on sparse data, spring failure probability was estimated to be 0.1. Thus, $P_{1a} = P_{2a} = 0.1$.

An LER search conducted by SEA uncovered 16 events related to MSIV accumulators between 1978 and 1995, a 17-year period; all events were reported at PWRs. During this period, approximately 60 PWRs were in operation, each with 2, 3, or 4 MSIVs. This amounted to about 20 million MSIV operable hours. With at least 2 time-related common cause failures during this period, the common cause failure rate (FACC) was estimated to be 10^{-7}/hour.

To derive an estimate for independent failures, it was assumed that a PWR licensee will postpone corrective action until the next cold shutdown, an average of about 6,000 hours. For time-related failures, the probability that a component is unavailable is the product of the failure rate and the average downtime. Therefore, the rate of occurrence of an accumulator failure while the redundant accumulator is still down is $(2 \times 6{,}000)(FA)^2$/hour, where FA is the rate of independent failures and the factor of 2 accounts for the fact that either accumulator may be the first to fail. To provide at least one such occurrence in 20 million MSIV hours, the estimate for the failure rate is given by FA $= 2 \times 10^{-6}$/hour.

Should the pressure of an accumulator on one MSIV fall below the design pressure, the BWR licensee may wait until the next cold shutdown to make repairs. This will average about 6,000 hours of downtime, regardless of whether the pressure is checked continuously or quarterly. Thus, the probability that design pressure would not be available in the inboard accumulator after installation of a monitoring/alarm system (P_{1c}) would be approximately the same as before, i.e., $P_{1b} = P_{1c} = (6{,}000)(FA + FACC) = (6{,}000)[10^{-7} + (2 \times 10^{-6})] = 0.012$.

Upon detection of simultaneous failure of both accumulators on one main steam line (both inboard and outboard MSIVs), licensees would go to cold shutdown to make repairs. For quarterly surveillance, the average downtime is about 1,000 hours. Therefore, probability of unavailability of design pressure in both accumulators on the broken steam line, P_{2b}, is given by:

$$
\begin{aligned}
P_{2b} &= 1{,}000[FACC + (2 \times 6{,}000)(FA)^2] \\
&= 1{,}000[10^{-7} + (12{,}000)(2 \times 10^{-6})^2] \\
&= 1{,}000[10^{-7} + (0.48 \times 10^{-7})] \\
&= 1.48 \times 10^{-4}
\end{aligned}
$$

Substituting the values stated above, the base case CDF is given by:

$$
\begin{aligned}
\bar{F} &= [(2 \times 10^{-6}/RY)(0.1)(0.012) + \\
&\qquad (1.2 \times 10^{-4}/RY)(0.1)(1.48 \times 10^{-4})] \\
&= (2.4 \times 10^{-9}/RY) + (1.8 \times 10^{-9}/RY) \\
&= 4.2 \times 10^{-9}/RY
\end{aligned}
$$

Upon detection of simultaneous failure of both accumulators on one main steam line (both inboard and outboard MSIVs), licensees would go to cold shutdown to make repairs. For quarterly surveillance, the average downtime would be reduced to 8 hours by the possible solution.

The probability of unavailability of design pressure in both accumulators on the broken steam line after installation of a monitoring/alarm system, P_{2c}, was given by:

$$\begin{aligned} P_{2c} &= 8[FACC + (2 \times 6{,}000)(FA)^2] \\ &= 8[10^{-7} + (12{,}000)(2 \times 10^{-6})^2] \\ &= 8[10^{-7} + (0.48 \times 10^{-7})] \\ &= 1.18 \times 10^{-6} \end{aligned}$$

Thus, following implementation of the possible solution, the adjusted case CDF (F*) is defined by:

$$\begin{aligned} \overline{F}^* &= F_1 P_{1a} P_{1c} + F_2 P_{2a} P_{2c} \\ &= [(2 \times 10^{-6}/RY)(0.1)(0.012) + (1.2 \times 10^{-4}/RY)(0.1)(1.18 \times 10^{-6})] \\ &= (2.4 \times 10^{-9}/RY) + (1.4 \times 10^{-11}/RY) \\ &= 2.414 \times 10^{-9}/RY \end{aligned}$$

Therefore, the reduction (Δ) in CDF is given by:

$$\begin{aligned} \Delta CDF &= \overline{F} - \overline{F}^* \\ &= (4.2 \times 10^{-9}/RY) - (2.414 \times 10^{-9}/RY) \\ &= 1.78 \times 10^{-9}/RY \end{aligned}$$

Consequence Estimate

Based on the assumptions that MSIV failure will result in consequences similar to those for a BWR-2 Release Category and that there will be a 2-hour delay prior to the initiation of fission product release from the core, the average consequence for an unisolated main steam line break was estimated[1686] to be approximately 5×10^8 man-rem. For the 37 affected plants with an average remaining operating life of 22 years, the total potential risk reduction (ΔW) associated with this issue is given by:

$$\begin{aligned} \Delta W &= (1.78 \times 10^{-9}/RY)(37)(22)(5 \times 10^8 \text{ man-rem}) \\ &= 724 \text{ man-rem} \end{aligned}$$

Cost Estimate

Industry Cost: It was assumed that plant modifications could be made during operation or scheduled outages. For MSIVs inside containment, it was assumed that instrumentation cables could be run through existing spare containment penetrations. The configuration assumed for each MSIV included one sensor circuit to generate an alarm to notify operators of accumulator air pressure loss; control cable and conduit will be required to be run from each transmitter to the control room.

It was estimated[1686] that the cost/plant for the modifications of 8 MSIVs to be $206,500 including hardware ($67,000), installation labor ($67,000), engineering ($24,000), and health physics ($80,500). Plant simulator modifications were estimated to cost an additional $50,000. Engineering analysis is expected to cost $22,600 for an FMEA along with a cost/benefit analysis for alternative solutions. Staff training and revisions to plant operating procedures were estimated to cost $40,100. Periodic inspection, surveillance, test and maintenance of additional hardware were estimated to cost an additional $147,300. For the 37 affected plants, the total industry cost was estimated to be (37)($466,500) or $17.3M.

NRC Cost: It was estimated that 4 man-weeks, or $9,080, would be required to issue a generic letter to licensees for the new alarms. Review and approval of licensee design changes and inspection of modifications were estimated to cost $21,700/plant or $802,900 for all 37 affected plants.

Total Cost: The total industry and NRC cost associated with the possible solution was estimated to be $(17.3 + 0.8)M or approximately $18.1M.

Impact/Value Assessment

Based on a potential public risk reduction of 724 man-rem and an estimated cost of $18.1M for a possible solution, the impact/value ratio was given by:

$$R = \frac{\$18.1\text{M}}{724 \text{ man-rem}}$$

$$= \$25{,}000/\text{man-rem}$$

Other Considerations

Affected Plants: It was conservatively estimated that no plant has alarms in place to monitor MSIV accumulator pressure. The total risk could be lower if some plants have already installed alarms.

License Renewal: Consideration of a license renewal period of 20 years would increase the public risk reduction to 1,383 man-rem. Additional maintenance costs for this renewal period would be ($30,000)(37) or $1.1M. Consideration of these two factors would reduce the impact/value score to approximately $13,900/man-rem.

CONCLUSION

Based on the impact/value ratio and the total risk reduction potential, this issue was placed in the DROP category.[1736] Consideration of a license renewal period of 20 years did not alter this conclusion.

REFERENCES

1684. Memorandum for E. Beckjord from T. Murley, "Request for Prioritization of Potential Generic Safety Issue - BWR MSIV Common Mode Failure Due to Loss of Accumulator Pressure," May 25, 1993.

1685. Memorandum for T. Murley from E. Beckjord, "Request for Prioritization of Potential Generic Safety Issue - BWR MSIV Common Mode Failure Due to Loss of Accumulator Pressure," June 29, 1993.

1686. SEA No. 95-3101-01-A:1, "Technical Information for Prioritization of Generic Safety Issues," Science and Engineering Associates, Inc., June 1996.

1736. Memorandum to M. Knapp from L. Shao, "Generic Issue No. 169, 'BWR MSIV Common Mode Failure Due to Loss of Accumulator Pressure,'" March 10, 1998.

ISSUE 173: SPENT FUEL STORAGE POOL

In November 1992, two engineers who had previously worked under contract for the Pennsylvania Power and Light Company (PP&L) filed a report contending that the design of the Susquehanna station failed to meet regulatory requirements with respect to sustained loss of the cooling function to the SFP that mechanistically results from a LOCA or a LOOP. PP&L and the engineers each made a series of additional submittals to the NRC and participated in public meetings with the NRC to describe their respective positions on a number of technical and licensing issues. In order to inform the nuclear power industry of the issues, NRC issued IN 93-83 on October 7, 1993. The staff evaluated the issues as they related to Susquehanna, using a probabilistic safety assessment, a deterministic engineering assessment and a licensing basis analysis, and issued an SER on June 19, 1995.

A generic action plan[1623] was developed with two parts: (1) Part A, which encompassed the staff's review of generic issues relating to the SFP at operating reactor facilities; and (2) Part B, which included applicable issues from the Part A review and concerns from the Dresden-1 special inspection,[1601] particular to permanently shutdown facilities with stored, irradiated fuel to establish evaluation criteria for spent fuel pools at permanently shutdown facilities. Part B was included after the special inspection at Dresden-1 determined that problems in implementing the facility's decommissioning plan combined with certain SFP design features created the potential for a substantial loss of SFP water inventory. Dresden-1, which is permanently shutdown, experienced containment flooding due to freeze damage to the service water system on January 25, 1994, and the licensee for Dresden-1 reported a similar threat to SFP integrity. This licensee report resulted in the special inspections[1601] of La Crosse, Humboldt Bay, Rancho Seco, Trojan, San Onofre-1, Yankee Rowe, and Indian Point-1. The two parts of this issue were evaluated separately.

ISSUE 173.A: OPERATING FACILITIES

DESCRIPTION

Historical Background

The principal concerns included in Part A of the generic action plan[1623] involved the potential for a sustained loss of SFP cooling capability, which was identified through the report filed with the NRC relating to Susquehanna, and the potential for a substantial loss of SFP coolant inventory, which was given renewed emphasis following the Dresden-1 special inspection. Postulated adverse conditions that may develop following a LOCA or a sustained loss of power to SFP cooling system components could prevent restoration of SFP decay heat removal. The heat and water vapor added to the building atmosphere by subsequent SFP boiling could cause failure of accident mitigation or other safety equipment and an associated increase in the consequences of the initiating event. Incomplete administrative controls combined with certain design features, particularly at the oldest facilities, may create the potential for a substantial loss of SFP coolant inventory and the associated consequences, which include high local radiation levels due to loss of shielding, unmonitored release of radiologically contaminated coolant, and inadequate cooling of stored fuel.

The action plan was intended to encompass SFP issues identified through a 1994 special inspection at Dresden-1, the staff's review of loss of SFP cooling concerns at Susquehanna, and other SFP concerns identified as part of this plan. Specific review areas identified through implementation of this action plan include plant design features and administrative controls that affect the probability of spent fuel pool boiling, adverse environmental effects on essential equipment due to boiling, significant loss of spent fuel pool coolant inventory, adverse radiological conditions, unplanned spent fuel pool reactivity changes, undetected spent fuel pool events, and adverse effects of control system actuations. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

The postulated events do not pose an undue risk to the public based on the availability of design features that help protect stored irradiated fuel, protect essential reactor safety systems, and prevent development of adverse radiological conditions. These design features include the provision of diverse means of cooling, the strong structural design of the spent fuel pool, the absence of drainage paths from the pool, the anti-syphon protection on piping within the spent fuel pool, the availability of multiple sources of make-up water, spent fuel pool instrumentation with control room annunciation, the maintenance of a substantial shutdown reactivity margin in the pool, radiation shielding provided by coolant inventory, and spent fuel pool water purification systems. Additionally, the relatively slow evolution of these events in the spent fuel pool resulting from the initial large cooling water inventory creates significant opportunity for operator recovery prior to experiencing adverse conditions or consequences.

Possible Solutions

Specific actions include: (1) determination of the safety significance of identified concerns; (2) determination of the facilities where the concerns may be applicable; (3) evaluation of the adequacy of present SFP designs; (4) evaluation of the adequacy of current NRC guidance for SFP designs; and (5) evaluation of the need for generic actions to address significant issues at operating and permanently shutdown facilities. Based on findings from these review areas and their risk significance, the staff will develop criteria for specific spent fuel pool operations for potential use in formulating generic communications, revisions of regulatory guidance, and other appropriate regulatory actions.

CONCLUSION

This issue was considered nearly-resolved[1731] since a solution had been identified and resolution was in progress with an approved Action Plan. It was later given a HIGH priority ranking in SECY-98-166.[1718]

In pursuing a resolution to this issue, the staff performed a comprehensive study of the Susquehanna SFP. The results of the special inspection of Dresden-1, after rupture of the SWS occurred inside containment, were transmitted to licensees in IN 94-38.[1624] The identification of concerns for evaluation and review of existing guidance were completed along with on-site safety assessments of spent fuel storage at Brunswick, Monticello, Comanche Peak, and Ginna. The assessment team concluded that the potential for a sustained loss of SFP cooling or a significant loss of SFP coolant inventory at the sites visited was remote, based on certain design features and operational controls. The team found that other concerns within the scope of the action plan review were much less significant in terms of risk at the plants visited. An FSAR-based review was undertaken to identify facilities whose design was not well represented by any of the facilities reviewed through on-site assessments. As a result, approximately 26 concerns were identified in the major review areas; additional concerns associated with the Millstone-1 SFP (adequacy of SFP cooling during refueling with a full core off-load) were included. Each concern was to be addressed on the basis of a qualitative safety assessment. The concern for SFP criticality control (Boraflex degradation) was pursued through issuance of an information notice and a planned generic letter.

Following reports[1693,1694] to the Commission on its findings, the staff committed to complete regulatory analyses associated with plant-specific backfits, implement plant-specific backfits, and complete revisions to Regulatory Guide 1.13[1697] and SRP[11] Sections 9.1.1 and 9.1.3. The regulatory analyses were pursued by NRR under the proposed rulemaking on shutdown and fuel storage pool operation. In July 1997, the staff's proposed rule was presented to the Commission in SECY-97-168[1695] following which, the Commission directed[1696] the staff not to issue the proposed rule. The staff will pursue regulatory improvement changes to Regulatory Guide 1.13[1697] and the SRP[11] and the impact of a license renewal period of 20 years will be considered in the resolution of the issue.

ISSUE 173.B: PERMANENTLY SHUTDOWN FACILITIES

DESCRIPTION

Historical Background

The staff issued Bulletin 94-01[1625] requesting all holders of licenses for nuclear power reactors that were permanently shut down with spent fuel in the spent fuel pool to take actions to ensure the quality of the SFP coolant, the ability to maintain an adequate coolant inventory for cooling and shielding, and the necessary support systems were not degraded. In order to evaluate the management controls and SFP activities at permanently shutdown reactors, the NRC initiated a series of special team inspections at permanently shutdown facilities with stored, irradiated fuel in the SFP. This Part B effort was expected to use the results of Part A activities to establish evaluation criteria for SFPs at permanently shutdown plants to support rulemaking and other generic activities initiated by NRR. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

The postulated events involving a loss of cooling do not pose undue risk to the public because of the low residual decay heat in the spent fuel at permanently shutdown reactors and the associated long period of time available for recovery. Concerns involving maintenance of the coolant quality and ability to control coolant inventory were addressed through the special inspection activities. Therefore, continued facility operation was justified.

Possible Solution

Specific actions included in Part B of the generic action plan[1623] were: (1) the determination of significant identified concerns from Part A applicable to permanently shutdown facilities; and (2) the evaluation and implementation of additional requirements specifically applicable to permanently shutdown facilities with stored, irradiated fuel.

CONCLUSION

This issue was considered nearly-resolved[1731] since a solution had been identified and resolution is in progress with an approved Action Plan. The staff determined that all significant identified concerns from Part A applicable to permanently shutdown facilities were encompassed by the special inspection activities which showed no significant deficiencies other than at Dresden-1. In response to the Dresden-1 Special Inspection findings, NRR proceeded with issuance of a decommissioning action plan. Thus, this issue was RESOLVED with no new requirements.

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.

1601. Memorandum to C. Serpan from A. Chaffee, "Nuclear Reactor Regulation (NRR) Input into Research NUREG-0933 (WITS Item 9400213)," February 13, 1996.

1623. Memorandum to A. Thadani from G. Holahan, "Task Action Plan for Spent Fuel Storage Pool Safety," October 13, 1994.

1624. NRC Information Notice 94-38, "Results of a Special NRC Inspection at Dresden Nuclear Power Station Unit 1 Following a Rupture of Service Water Inside Containment," May 27, 1994.

1625. NRC Bulletin 94-01, "Potential Fuel Pool Draindown Caused by Inadequate Maintenance Practices at Dresden Unit 1," April 14, 1994.

1693. Memorandum to Chairman Jackson, et al., from J. Taylor, "Report on Survey of Refueling Practices," May 21, 1996.

1694. Memorandum to Chairman Jackson, et al., from J. Taylor, "Resolution of Spent Fuel Storage Pool Action Plan Issues," July 26, 1996.

1695. SECY-97-168, "Issuance for Public Comment of Proposed Rulemaking Package for Shutdown and Fuel Storage Pool Operation," July 30, 1997.

1696. Memorandum to L. Callan from J. Hoyle, "Staff Requirements - SECY-97-168 - Issuance for Public Comment of Proposed Rulemaking Package for Shutdown and Fuel Storage Pool Operation," December 11, 1997.

1697. Regulatory Guide 1.13, "Spent Fuel Storage Facility Design Basis," U.S. Nuclear Regulatory Commission, (Rev. 1) December 1975, (Draft Rev. 2) December 1981.

1718. SECY-98-166, "Summary of Activities Related to Generic Safety Issues," July 6, 1998.

1731. Memorandum for W. Russell from D. Morrison, "Prioritization of the NRR Action Plans Submitted to RES on February 13, 1996," June 24, 1996.

ISSUE 174: FASTENER GAGING PRACTICES

This issue has two parts that were evaluated separately.

ISSUE 174.A: SONGS EMPLOYEES' CONCERN

DESCRIPTION

Historical Background

A San Onofre Nuclear Generating Station (SONGS) employee filed a concern with the SONGS Employee Program concerning the acceptance of fastener threads using GO/NO GO thread gages (System 21) rather than variables gaging (System 22). Because of the employee's displeasure with the response received from the SONGS Employee Program, an allegation was filed with the NRC; he was later joined by three other SONGS employees with the same allegation.

SONGS purchased equipment to conduct System 22 thread gaging measurements on a sample of fasteners purchased for the SONGS warehouse. The measurements were made in the commercial dedication laboratory. The fasteners were purchased with the requirement that they are acceptable using a System 21 measurement. Between a quarter and a third of the fasteners tested using System 22 did not meet the System 22 requirements, although they did meet the System 21 requirements. An extensive investigation by SONGS and an independent investigation by the NRC resulted in the conclusion that fasteners that failed testing using System 22 but passed testing using System 21 did not result in an unsafe condition. Each alleger was interviewed, a copy of the allegations was sent to each alleger, and a response was provided to each of the technical allegations. A two-week inspection at the SONGS warehouse was conducted, during which, no unsafe conditions were observed. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

The safety concern is that the use of GO/NO GO gages does not ensure that all of the material limits specified in ASME B1.1 have been met and unsafe conditions could result from threaded fastener failures.

CONCLUSION

All of the technical concerns identified by the allegers have been addressed and they were notified in writing by the NRC. Thus, this issue was RESOLVED and no new requirements were established.[1731]

ISSUE 174.B: JOHNSON GAGE COMPANY CONCERN

DESCRIPTION

Historical Background

Concerns were raised by employees at the Johnson Gage Company regarding the gaging of fasteners. The employees approached the NRC staff with a concern about the use of GO/NO GO gages (System 21) instead of the use of variables gaging (System 22) for determining the acceptability of fastener threads. The staff pointed out to the Johnson Gage employees that this issue had low safety significance. The Johnson Gage employees sent numerous letters to the Chairman of the NRC, had congressmen write to the Chairman of the NRC, had NIST write the NRC staff, and met with Chairman Selin and Chairman Jackson to discuss their concerns. The staff responded to all of the correspondence from the Johnson Gage employees, met with congressional staffers, responded to congressional correspondence, met with NIST staff members, and submitted a code inquiry to the ASME. No safety issues could be identified and ASME stated that there were no compliance issues involved. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

The safety concern is that the use of GO/NO GO gages does not ensure that all of material limits specified in ASME B1.1 have been met and unsafe conditions could result from threaded fastener failures.

CONCLUSION

Letters were sent by the NRC to the Johnson Gage Company employees stating that that this issue had low safety significance and no compliance issues were involved. Thus, the issue was RESOLVED and no new requirements were established.[1731]

REFERENCES

1601. Memorandum to C. Serpan from A. Chaffee, "Nuclear Reactor Regulation (NRR) Input into Research NUREG-0933 (WITS Item 9400213)," February 13, 1996.

1731. Memorandum for W. Russell from D. Morrison, "Prioritization of the NRR Action Plans Submitted to RES on February 13, 1996," June 24, 1996.

ISSUE 175: NUCLEAR POWER PLANT SHIFT STAFFING

DESCRIPTION

Historical Background

The NRC post-TMI-2 accident shift staffing policy was codified through the issuance of 10 CFR 50.54(m) which specified minimum requirements for licensed operators at nuclear power reactor sites but not for non-licensed personnel. Subsequently, the NRC promulgated additional shift staffing requirements and specified actions required by certain plant personnel during an emergency. These include personnel requirements for fire brigades and emergency response personnel contained in Appendix R and Appendix E to 10 CFR 50, respectively, and the shift staffing implications commensurate with the reporting/notification requirements contained in 10 CFR 50.73 and 10 CFR 72. In addition, Generic Letter 86-04[1650] encouraged licensees to combine one of the required Senior Reactor Operator (SRO) positions with the Shift Technical Advisor (STA) position forming a dual role position (SRO/STA).

Subsequent events over the last several years at some nuclear power plants have led to questions regarding the adequacy of the shift staffing level requirements. In particular, concern was raised regarding the minimum shift staffing (including non-licensed personnel) needed during an event which challenges a backshift crew's ability to perform all necessary functions.

Information Notice (IN) 91-77[1651] was issued to alert licensees to the problems that could result from inadequate control of shift staffing levels. IN 91-77[1651] identified fire brigade and security response as additional duties that some licensees had assigned to operations staff, and reminded licensees that 10 CFR 50.54(m) specifies only minimum staffing levels for licensed operators and does not address personnel availability for all of the necessary actions specified in the licensees' administrative controls and required by an event.

In NUREG-1275,[1079] Volume 8, concerns were raised regarding the use of STAs to perform duties during plant events that may interfere with their ability to perform their primary function of providing engineering and accident assessment advice to the shift supervisor. NRR completed a survey of licensee staffing practices, including how plant personnel were distributed, to ensure necessary actions could be accomplished during an event.

NUMARC provided[1655] the NRC with the results of its survey of industry staffing practices; this survey documented responses from 110 of the 113 licensees solicited. Ninety-three percent of the respondents stated that they conducted a staffing review after receiving IN 91-77[1651]; the 7% that did not respond had recently conducted a shift complement staffing study. Some licensees increased staffing to accomplish required tasks, reassigned duties to more evenly distribute the workload, or modified equipment to reduce the need for operator action. All respondents confirmed the adequacy of their existing staffing practices against the two actual occurrences cited in IN 91-77.[1651]

Information Notices 93-44[1652] and 93-81[1653] were issued to alert the industry to the operational challenges that could result when responding to an event with minimum staffing levels, or when STAs are distracted from their accident assessment duties by serving in concurrent roles such as fire brigade leader or communicator. NRR requested RES to evaluate the adequacy of the minimum staffing levels required by 10 CFR 50.54(m). The staff also issued two reports to the Commission: (1) SECY-93-184[1656] informed the Commission that an NRR survey indicated operators at some plants were concerned about the adequacy of their staffing to handle certain complex events, and several AEOD event reviews indicated that shift resources had not been effectively allocated to ensure that individuals were not overburdened; and (2) SECY-93-193[1657] summarized the staff's findings concerning the industry's implementation of the STA position at nuclear power plants. The staff found that the STA was an on-call position at 20 of the 79 sites using dedicated STAs and was concerned about the ability of on-call STAs to maintain an adequate awareness of plant configuration and status. The staff also reported that some licensees assign the STA to concurrent roles such as fire brigade leader or communicator during an event.

NRR was assigned the lead to evaluate the effectiveness of licensee shift staffing practices, with the focus on staffing levels outside the control room, and a Task Action Plan was approved. This plan addresses the adequacy of shift staffing level requirements at nuclear power plants (NPPs) and includes assessment of the generic implications of assigning conflicting multiple responsibilities to the operating staff of NPPs for response to resource-intensive accidents. The plan considers whether there is a need to change or develop regulatory guidance regarding shift staffing requirements at NPPs. The plan included the issuance of an information notice to provide licensees the results and insights gained. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

The minimum shift staffing (including non-licensed personnel) needed during an event challenges a backshift crew's ability to perform all necessary functions.

Possible Solution

Research on the subject was conducted and included: (1) a review and evaluation of experience and events for which staffing was a contributing factor; and (2) a detailed on-site survey of staffing practices at 7 facilities, including tabletop and walk-through exercises for specific accident sequences that could challenge staff resources. Upon completion of the research, the NRC was expected to review the results and issue an Information Notice regarding the findings. In April 1994, NRR broadened the scope of the staffing research and requested RES to include all licensee staff initially needed for an event.

CONCLUSION

The shift staffing study was published by BNL in two reports to the NRC and included the following findings:

(1) Licensees did not use a systematic process for establishing site-specific staffing levels, despite the availability of such methods.

(2) For all plants surveyed, the TS staffing requirements for SROs and ROs were equivalent to the minimum requirements of 10 CFR 50.54(m).

(3) Licensees frequently assign plant-specific tasks to be performed during an event that are not required by regulation.

(4) There was significant variation between plants in the number of licensed and non-licensed personnel that were administratively required.

(5) During scenario walk-throughs, similar-vendor licensees made significantly different decisions, resulting in very different control room activities and in-plant tasks.

(6) For all plants surveyed, the typical staffing levels were greater than the TS staffing requirements; however, these licensees were actively engaged in reducing operations and management costs. Such reductions could impact their future staffing levels.

Information Notice 95-48[1654] was issued to provide licensees with the results and the insights gained during the staff study. Although there had been, and continue to be, occasional events in which the adequacy of shift staffing and task allocation were called into question, the staff believed that, at the time the Notice[1654] was issued, insufficient basis existed for a regulatory analysis which would support generic regulatory action in these areas. Accordingly, the staff will continue to monitor the adequacy of shift staffing and task allocation for events in which they are questioned, and will take plant-specific regulatory action as appropriate. Based on the actions described above, this issue was RESOLVED and no new requirements were established.[1731]

REFERENCES

1079. NUREG-1275, "Operating Experience Feedback Report," U.S. Nuclear Regulatory Commission, (Volume 8) December 1992.

1601. Memorandum to C. Serpan from A. Chaffee, "Nuclear Reactor Regulation (NRR) Input into Research NUREG-0933 (WITS Item 9400213)," February 13, 1996.

1650. NRC Letter to All Power Reactor Licensees and Applicants for Power Reactor Licenses, "Policy Statement on Engineering Expertise on Shift (Generic Letter 86-04)," February 13, 1986.

1651. NRC Information Notice 91-77, "Shift Staffing at Nuclear Power Plants," November 26, 1991.

1652. NRC Information Notice 93-44, "Operational Challenges During a Dual-Unit Transient," June 15, 1993.

1653. NRC Information Notice 93-81, "Implementation of Engineering Expertise on Shift," October 12, 1993.

1654. NRC Information Notice 95-48, "Results of Shift Staffing Study," October 10, 1995.

1655. Letter to B. Boger (NRC) from R. Whitesel (NUMARC), December 29, 1992.

1656. SECY-93-184, "Shift Staffing at Nuclear Power Plants," June 29, 1993.

1657. SECY-93-193, "Policy on Shift Technical Advisor Position at Nuclear Power Plants," July 13, 1993.

1731. Memorandum for W. Russell from D. Morrison, "Prioritization of the NRR Action Plans Submitted to RES on February 13, 1996," June 24, 1996.

ISSUE 176: LOSS OF FILL-OIL IN ROSEMOUNT TRANSMITTERS

DESCRIPTION

Historical Background

The Rosemount Transmitter Review Group (RTRG) was established[1659] to perform an assessment of the actions taken to address Rosemount transmitter oil-loss concerns. This assessment included an evaluation of the adequacy of the information and actions specified in NRC Bulletin 90-01,[1658] Supplement 1, which informed licensees of activities undertaken by the NRC and the industry in evaluating and addressing loss of fill-oil in Rosemount transmitters manufactured prior to July 11, 1989, and requested licensees to take actions to resolve the concerns.

An action plan was developed by the staff and integrated the following RTRG recommendations to address Rosemount transmitter loss of fill-oil concerns: (1) conduct temporary instruction (TI) inspections to verify commitments made by licensees to address the requested actions of NRC Bulletin 90-01,[1658] Supplement 1, and to gather plant-specific data on Rosemount transmitter failures; (2) establish a dialogue with Rosemount, Inc., on Rosemount transmitter failure information; (3) review NPRDS data on Rosemount transmitter performance; and (4) review EPRI Report TR-102908, "Review of Technical Issues Related to the Failure of Rosemount Pressure Transmitters Due to Fill-Oil Loss," dated August 1994. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

Loss of fill-oil in Rosemount transmitters was determined to be a potentially undetected means of common mode failure. Such failures could result in loss of automatic reactor protection and engineered safety feature actuations.

Possible Solution

The staff determined that actions were needed by licensees to ensure that safety-related functions were maintained. These actions were first identified in Bulletin 90-01[1658] and subsequently modified in Bulletin 90-01,[1658] Supplement 1. The time frame for this action plan was based on the fact that licensees had implemented the requested actions of Bulletin 90-01,[1658] Supplement 1, and the plan was intended only as confirmation of the adequacy of the actions called for in the Bulletin.[1658]

The activities specified in the action plan were completed as a follow-up and verification of the implementation of the requested actions in Bulletin 90-01,[1658] Supplement 1. Licensees addressed the common mode failure concerns by either replacing affected transmitters with newly designed transmitters which corrected the oil leakage problem, or subjecting affected transmitters to enhanced surveillance monitoring to ensure their proper performance. A two-year period was established for completing the necessary verification activities recommended by the RTRG including TI inspections and reviews of recent Rosemount transmitter performance.

CONCLUSION

Temporary Instruction (TI) 2515/122, "Evaluation of Rosemount Pressure Transmitter Performance and Licensee Enhanced Surveillance Programs," was issued on March 17, 1994 and inspections were initiated in May 1994. Based on the results of the TI effort, the staff determined that licensees were effectively addressing the Rosemount transmitter loss of fill-oil issue by, in general, following the requested actions of Bulletin 90-01,[1658] Supplement 1, and the manufacturer's drift trending guidance.

The staff met periodically (between January 1994 and September 1995) with Rosemount, Inc. to exchange information on Rosemount transmitter performance. In addition, the staff completed NPRDS reviews for Rosemount transmitter failure information during the same period. Based on the information presented by Rosemount, Inc. and the results of the NPRDS reviews, the staff concluded that there was a significant decrease in the number of fill-oil failures since the issuance of Bulletin 90-01,[1658] Supplement 1.

On February 15, 1995, the staff completed its review of EPRI Report TR-102908 and confirmed that it was substantially in agreement with the previous conclusions, guidance, and requested actions contained in Bulletin 90-01,[1658] Supplement 1.

Based on the results of the above activities completed, the staff confirmed that all pertinent information regarding loss of fill-oil in Rosemount transmitters was contained in Bulletin 90-01,[1658] Supplement 1, and Rosemount technical guidance. Therefore, the staff concluded that the safety concern of the issue had been effectively resolved by the actions taken and no changes or additional actions were warranted. Thus, this issue was RESOLVED and no new requirements were issued.[1731]

REFERENCES

1601. Memorandum to C. Serpan from A. Chaffee, "Nuclear Reactor Regulation (NRR) Input into Research NUREG-0933 (WITS Item 9400213)," February 13, 1996.

1658. NRC Bulletin No. 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount," March 9, 1990, (Supplement 1) December 22, 1992.

1659. Memorandum for R. Zimmerman, et al., from J. Sniezek, "Review of Rosemount Transmitter Issues," May 21, 1993.

1731. Memorandum for W. Russell from D. Morrison, “Prioritization of the NRR Action Plans Submitted to RES on February 13, 1996,” June 24, 1996.

ISSUE 177: VEHICLE INTRUSION AT TMI

DESCRIPTION

Historical Background

At 6:53 a.m. on February 7, 1993, an intruder drove into the TMI site owner-controlled area, through a gate into the protected area of Unit 1, and crashed through a roll-up door on the turbine building. TMI security reported this event to the NRC operations officer and declared a Security Emergency upon determining that the protected area of the plant had been comprised. At 7:23 a.m., the TMI-1 shift supervisor officially notified the NRC Headquarters operations officer that he had declared a Site Area Emergency effective at 7:05 a.m. At 10:57 a.m., TMI security personnel discovered and apprehended the intruder at the bottom of the turbine building. The intruder challenged security barriers and programs, disrupted normal site operations, and was not apprehended for 4 hours. However, the intruder was unarmed, entered only the protected area, and did not breach a vital area boundary. This issue was identified in an NRR memorandum[1601] to RES in February 1996.

Safety Significance

Although the event resulted in no actual adverse reactor safety consequences and was of minimal safety significance, some significant issues were raised. The IIT report[1665] highlighted the fact that: (1) the performance objectives of 10 CFR 73 for establishing and maintaining a physical protection system did not effectively address the use of a vehicle for entering the protected area in a manner similar to the TMI event; (2) the method of entry into the protected area significantly affected the security program response strategy toward protecting the vital areas and protecting against radiological sabotage; and (3) the NRC had not effectively defined and communicated its expectations for the licensee's security program performance in response to vehicle intrusions. The IIT report also raised concerns related to the emergency response of TMI, the NRC, and other organizations and the NRC security inspection program.

Solution

An action plan[1662] was developed by AEOD and included 8 issues that arose from NUREG-1485,[1665] the report on the event by the incident investigation team (IIT). Resolution of these issues was assigned to NRR, NMSS, AEOD, and Region I with responsibilities for each Office delineated by the EDO.[1662]

CONCLUSION

Between February 10 and March 10, 1993, the staff tested the Emergency Response Data System (ERDS) link with all reactor units that had not been linked to ERDS since October 1992. During these tests, the staff found deficiencies in the performance of some links; these deficiencies were corrected and the links were retested. Generic Letter 93-01[1663] was issued to implement an ERDS quarterly testing program.

The staff held an enforcement conference at Region I headquarters with GPU Nuclear on August 24, 1993 to discuss a violation regarding the delay in calling emergency response personnel. Region 1 issued a Severity Level III notice of violation (with no civil penalty) to the licensee on October 20, 1993. The licensee responded with appropriate corrective actions on November 19, 1993.

In September 1993, the NRC staff meet with the FBI to discuss concerns raised as a result of the TMI intrusion. The FBI updated its contingency plans maintained at the field office level for responding to nuclear-related incidents.

Information Notice 93-94[1664] was issued to alert other licensees of the event and to inform them of NRC concerns related to protected area barriers and intrusion assessment systems, the interface between operations, emergency response, and physical security response activities, the effect of security on licensee emergency response, the process for implementing 10 CFR 50.54(x) and (y) provisions, and communications systems. The core inspection procedure for physical security was revised on April 15, 1994, to provide periodic in-depth performance-oriented review of the site security forces.

A final Rule was published on August 1, 1994, to modify the design basis threat for radiological sabotage to include: (1) use of a land vehicle by adversaries for transporting personnel and their hand equipment to the proximity of vital areas; and (2) a land vehicle bomb (in response to the bombing of the World Trade Center later in February, 1993). This Rule also required licensees to install vehicle control measures, including vehicle barrier systems, to protect against the malevolent use of a land vehicle.

From September 21 to October 3, 1995, letters were sent to all licensees regarding lessons learned from the TMI event and the NRC operational safeguards response evaluations. These letters transmitted safeguards information that could assist licensees in their efforts to protect against a determined, violent, external assault on a plant. Based on the actions described above, this issue was RESOLVED and new requirements were established.[1731]

REFERENCES

1601. Memorandum to C. Serpan from A. Chaffee, "Nuclear Reactor Regulation (NRR) Input into Research NUREG-0933 (WITS Item 9400213)," February 13, 1996.

1662. Memorandum for E. Jordan, et al., from J. Taylor, "Unauthorized Forced Entry Into the Protected Area at Three Mile Island Unit 1 on February 7, 1993 (NUREG-1485)," June 18, 1993.

1663. NRC Letter to All Holders of Operating Licenses or Construction Permits for Nuclear Power Reactors, Except for Big Rock Point and Facilities Permanently or Indefinitely Shut Down, "Emergency Response Data System Test Program (Generic Letter 93-01)," March 3, 1993.

1664. NRC Information Notice 93-94, "Unauthorized Forced Entry Into the Protected Area at Three Mile Island Unit 1 on February 7, 1993," December 9, 1993.

1665. NUREG-1485, "Unauthorized Forced Entry Into the Protected Area at Three Mile Island Unit 1 on February 7, 1993," U.S. Nuclear Regulatory Commission, April 1993.

1731. Memorandum for W. Russell from D. Morrison, "Prioritization of the NRR Action Plans Submitted to RES on February 13, 1996," June 24, 1996.