NUREG-0420
Supplement No. 7

Safety Evaluation Report
related to the operation of Shoreham Nuclear Power Station, Unit No. 1

Docket No. 50-322

Long Island Lighting Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

September 1984

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ABSTRACT

Supplement 7 (SSER 7) to the Safety Evaluation Report on Long Island Lighting Company's application for a license to operate the Shoreham Nuclear Power Station, Unit 1, located in Suffolk County, New York, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement addresses several items that have been reviewed by the staff since the previous supplement was issued.

TABLE OF CONTENTS

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

TABLE OF CONTENTS (continued)

ACRONYMS

ADS	automatic depressurization system
ANSI	American National Standards Institute
ARS	amplified response spectra
ASLB	Atomic Safety and Licensing Board
ASME	American Society of Mechanical Engineers
BNL	Brookhaven National Laboratory
BOP	balance of plant
BTP	Branch Technical Position
BWR	boiling water reactor
CFR	Code of Federal Regulations
CRAC	control room air conditioning
DAR	Design Assessment Report
DBE	design-basis event
DCRDR	detailed control room design review
DPO	differing professional opinion
EAL	emergency action levels
ECCS	emergency core cooling system
E&DCR	engineering and design coordination report
EOC	emergency operations center
EPZ	emergency planning zone
ERF	emergency response facility
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
FEMA	Federal Emergency Management Agency
FSAR	Final Safety Analysis Report
GDC	General Design Criteria(on)
GE	General Electric
HPCI	high pressure coolant injection
HVAC	heating, ventilation, and air conditioning
ICC	inadequate core cooling
IDR	independent design review
IDVP	independent design verification program
IE	Office of Inspection and Enforcement (Nuclear Regulatory Commission)
IEB	Office of Inspection and Enforcement Bulletin
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress corrosion cracking
ISI	inservice inspection
IST	inservice testing
JIO	justification interim operation

LER	licensee event report
LILCO	Long Island Lighting Company (applicant)
LOCA	loss-of-coolant accident
LPAC	lead plant acceptance criteria
LPCI	low pressure coolant injection
LPCS	low pressure core spray
LTP	long-term project
NAWAS	national warning system
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
OBE	operating basis earthquake
PCV	pressure control valves
PDA	preliminary design assessment
PP&L	Pennsylvania Power & Light
PRA	probabilistic risk analysis
PSAR	Preliminary Safety Analysis Report
PWR	pressurized water reactor
QA	quality assurance
RBSVS	reactor building standby ventilation system
RCIC	reactor core isolation cooling
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RECS	radiological emergency communication system
RG	regulatory guide
RHR	residual heat removal
RPV	reactor pressure vessel
RRS	required response spectra
RSP	remote shutdown panel
RWLMS	reactor water level measurement system
SAI	Science Applications, Inc.
SBO	station blackout
SCM	steam condensing mode
SDV	scram discharge volume
SER	Safety Evaluation Report
SLCS	standby liquid control system
SQRT	seismic qualification review team
SRO	senior reactor operator
SRP	Standard Review Plan (NUREG-0800)
SRV	safety/relief valve
SSE	safe shutdown earthquake
SSER	Safety Evaluation Report Supplement
SWEC	Stone and Webster Engineering Company
4T	tall temperature test tank
TES	Teledyne Engineering Services
TIP	traversing incore probe
TRS	test response spectra
WLMS	water level monitoring system

1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

The Nuclear Regulatory Commission's Safety Evaluation Report (SER) (NUREG-0420) on the application by Long Island Lighting Company (LILCO or applicant) to operate the Shoreham Nuclear Power Station was issued by the Nuclear Regulatory Commission staff (NRC staff) on April 10, 1981. Supplement 1 (SSER 1) to the Shoreham SER was issued in September 1981; SSER 2 was issued in February 1982; SSER 3 was issued in February 1983; SSER 4 was issued in September 1983; and SSER 5 was issued in April 1984; and SSER 6 was issued in July 1984.

Each of the sections in this SSER 7 is numbered the same as the section of the SER that is being updated. The discussions in this report are supplementary to and not in lieu of the discussions in the SER, except where specifically noted.

Copies of this report are available for public inspection at the Commission's Public Document Room, 1717 H Street, NW, Washington, D.C. 20555 and at the Shoreham-Wading River Public Library, Route 25A, Shoreham, New York 11786. Copies are also available for purchase from the sources indicated on the inside front cover. The NRC documents and other project-related documents cited in this report are available as described on the inside front cover.

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1.7 Outstanding Issues

In Section 1.7 of the SER, the NRC staff identified 61 outstanding issues that were not resolved at the time of issuance of the SER. This report discusses the resolution of a number of these items previously identified as open. The items identified in Section 1.7 of the SER are listed below with status of each item. If the item is discussed in this supplement, the section where the item is discussed is identified. The resolution of the remaining outstanding issues will be discussed in future supplements to the SER.

Item		Status	Section
(1)	Pool dynamic loads	Resolved	
(2)	Masonry walls	Resolved	
(3)	Piping vibration test program - small bore piping/instrumentation lines	Resolved	
(4)	Piping vibration test program - safety-related snubbers	Resolved	
(5)	LOCA loadings on reactor vessel supports and internals	Resolved	
(6)	Downcomer fatique analysis	Resolved	
(7)	Piping functional capability criteria	Resolved	
(8)	Dynamic qualification	Resolved with license condition	3.10
(9)	Environmental qualification	Resolved with license condition	3.11
(10)	Seismic and LOCA loadings	Resolved	4.2.3.4
(11)	Supplemental ECCS calculations with NUREG-0630 model	Resolved with license condition	
(12)	ODYN-Generic letter 81-08	Resolved	
(13)	NUREG-0619 - feedwater nozzle and control rod return line cracking - Generic Letter 81-11	Resolved	
(14)	Jet pump holddown beam	Resolved	
(15)	Inservice testing of pumps and valves	Resolved	
(16)	Leak testing of pressure isolation valves	Resolved	

Item		Status	Section
(17)	SRV surveillance program	Resolved	
(18)	NUREG-0313	Resolved	5.2.6
(19)	Preservice inspection	Resolved	
(20)	Appendix G - IV.A.2.a	Resolved	
(21)	Appendix G - IV.A.2.c	Resolved	
(22)	Appendix G - IV.A.3	Resolved	
(23)	Appendix G - IV.B	Resolved	
(24)	Appendix H - II.C.3b	Resolved	
(25)	RCIC	Resolved	
(26)	Suppression pool bypass	Resolved	
(27)	Steam condensation downcomer lateral loads	Resolved	
(28)	Steam condensation oscillation and chugging loads	Resolved	
(29)	Quencher air clearing load	Resolved	
(30)	Drywell pressure history	Resolved	
(31)	Impact loads on grating	Resolved	
(32)	Steam condensation submerged drag loads	Resolved	
(33)	Pool temperature limit	Resolved	6.2.1.8
(34)	Quencher arm and tie-down loads	Resolved	
(35)	Containment isolation	Resolved	
(36)	Containment purge system	Resolved	
(37)	Secondary containment bypass leakage	Resolved	
(38)	Fracture prevention of containment pressure boundary	Resolved	
(39)	Emergency procedures	Resolved	

Item		Status	Section
(40)	LOCA analyses	Resolved	
(41)	LPCI diversion	Resolved	
(42)	Flow meter	Resolved	
(43)	Loss of safety function after reset	Resolved	7.3.6
(44)	Level measurement errors	Resolved	
(45)	Fire protection	Resolved	
(46)	IE Bulletin 79-27	Resolved	
(47)	Control system failures	Resolved	
(48)	High-energy line breaks	Resolved	
(49)	DC system monitoring	Resolved	
(50)	Low and/or degraded grid voltage condition	Resolved	
(51)	Fracture toughness of steam and feedwater line materials	Resolved	
(52)	Management organization	Resolved	
(53)	Emergency planning (onsite)	Resolved pending confirmation	13.3
(54)	Security	Resolved	
(55)	Q-list	Resolved	
(56)	Financial qualification	Resolved	
(57)	TMI-2 requirements:		
	Shift technical advisor	Resolved with license condition	
	Shift supervisor administrative duties	Resolved	
	Shift manning	Resolved	
	Upgrade operator training	Resolved	
	Training programs - operators	Resolved	I.A.2.3

Item	Status	Section
Organization and management	Resolved	
Procedures for transients and accidents	Resolved	
Shift relief and turnover procedures	Resolved	
Control room access	Resolved	
Dissemination of operating experiences	Resolved	
Verify correct performance of operating activities	Resolved	
Vendor review of procedures	Resolved	
Emergency procedures	Resolved	
Control room design review	Resolved with license condition	I.D.1
Training during low-power testing	Resolved	I.G.1
Reactor coolant system vents	Resolved	
Plant shielding	Resolved	
Post-accident sampling	Resolved with license condition	
Degraded core training	Resolved	
Hydrogen control	Resolved	
Relief and safety valves	Resolved	II.D.1
Valve position indication	Resolved	
Dedicated hydrogen penetrations	Resolved	
Containment isolation dependability	Resolved	II.E.4.2
Accident-monitoring instrumentation		
Attachment 1	Resolved with post-implementation review	
Attachment 2	Resolved	

Item	Status	Section
Attachment 3	Resolved	
Attachment 4	Resolved	
Attachment 5	Resolved	
Attachment 6	Resolved	
Inadequate core cooling	Resolved	II.F.2
IE Bulletins		
Item 5	Resolved	II.K.1.5
Item 10	Resolved	II.K.1.10
Item 22	Resolved	
Item 23	Resolved	
Bulletins and Order Task Force		
Item 3	Resolved	
Item 13	Resolved	II.K.3.13
Item 16	Resolved	
Item 17	Resolved	
Item 18	Resolved	II.K.3.18
Item 21	Resolved	
Item 22	Resolved	
Item 24	Resolved	
Item 25	Resolved	
Item 27	Resolved	
Item 28	Resolved	
Item 30	Resolved	
Item 31	Resolved	

Item		Status	Section
	Item 44	Resolved	
	Item 45	Resolved	
	Item 46	Resolved	
	Emergency preparedness - short term	Under review	
	Upgrade emergency support facilities	Resolved	13.3.5
	Emergency preparedness - long term	Under review	
	Primary coolant outside containment	Resolved	
	Improved iodine monitoring	Resolved	
	Control room habitability	Resolved	II.D.3.4
(58)	Reactor vessel materials toughness	Resolved	
(59)	Control of heavy loads - Generic Letter 81-07	Resolved	
(60)	Station blackout - Generic Letter 81-04	Resolved pending confirmation	
(61)	Scram system piping	Resolved	
(62)	Remote shutdown system	Resolved with license condition	7.4.3
(63)	Design verification	Resolved	17.7
(64)	Loose parts monitoring system	Resolved	
(65)	Reactor building flooding	Resolved	3.12
(66)	Deep draft pumps (IEB-79-15)	Resolved	3.13
(67)	Reactor internal and core support material	Resolved with license condition	4.5.2
(68)	GHOSH code	Resolved	6.2.7
(69)	LPCI annunciator	Resolved	7.3.1
(70)	Core spray logic	Resolved	7.3.10

3 DESIGN OF STRUCTURES, COMPONENTS, EQUIPMENT, AND SYSTEMS

3.10 Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment

3.10.1 Background

In SSER 3 and SSER 4, the staff identified several seismic and dynamic review team concerns still to be addressed by the applicant. In this supplement, the staff provides an updated report on the resolution of these concerns, as well as the staff's conclusion on the Shoreham long-term operability assurance program for deep draft pumps. This evaluation is based on the information presented in the applicant's submittals of December 29, 1982, and June 6, 28, and 30, August 11, and October 7, 1983.

3.10.2 Justification for Interim Operation

The applicant has provided further justification for interim operation (JIO) for the equipment items that will be qualified after the fuel load. The staff has found this justification acceptable, as described below.

3.10.2.1 Radiation Monitoring System (Mark 1D11*PNL-117A and B)

The channels for each of the two high range area monitors are mechanically isolated by barriers and electrically separated. Hence, failure of one component in one channel will not affect the components in the other channel. If both monitors were to fail, the extent of core damage could still be estimated by analyzing containment atmosphere samples obtained using the post-accident sampling system. Because the high range area monitors are not safety related, failure of both monitors would not degrade the safety function of any other components required for safe shutdown. On the basis of the above consideration, the staff finds interim operation of the unqualified Class 1E cabinets and internals acceptable for a power level not to exceed 5%.

3.10.2.2 Radiation Monitoring System (Mark 1D11*P-126, 134)

The specific items of concern in this system are the auxiliary pump skids used to supply the sample air to the post-accident station vent and reactor building standby vent monitors. If there is seismic failure of the pump skids, alternate means such as post-accident sampling and/or grab sampling of the effluents and normal range monitors are available for the applicant to determine the gaseous effluent releases from the plant. Also, the buildup of radioactivity inventory during operation at a power level up to 5% will be comparatively small. In view of these considerations, the staff finds interim operation acceptable for a power level not to exceed 5%.

3.10.2.3 Scram Discharge Volume (SDV) Vent and Drain Valves

The required safety function of these valves is to close in the event of a scram, thus isolating the SDV from the radwaste drain system. There are two vent valves (F010 and F180) and two drain valves (F011 and F181) in series.

Only one vent valve and one drain valve must close to isolate the SDV. Vent and drain valves identical to those in the Shoreham design recently underwent successful dynamic testing. Even if these valves were to fail open, the resulting leakage would be less than that resulting from a postulated scram discharge system pipe break (as discussed in NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping"). Thus, it should be possible to isolate this leakage by closing a valve upstream of the scram discharge volume, either by resetting scram or manually. On the basis of the above, the staff concludes that interim operation up to 5% power is acceptable without full seismic qualification of the SDV vent and drain valves.

3.10.2.4 SDV Solenoid Valves (F009, F182)

The required safety function of the solenoid valves is to open (de-energize) and bleed air from the operators for one set of SDV vent and drain valves, thereby closing them. Both solenoid valves would have to fail in the closed position (energized from Class 1E power supplies) to preclude bleeding the air from at least one set of vent and drain valves. If both valves failed closed, the ability to scram would still be unaffected. As discussed above, the only adverse effect is leakage through the drain system, and that leakage is less than the leakage discussed in NUREG-0803. On the basis of the above consideration, the staff concludes that interim operation prior to full power operation with the solenoid valve not fully seismically qualified is acceptable. In this context, "prior to full power operation," means prior to full power range testing during the power ascension program.

3.10.2.5 High Pressure Coolant Injection (HPCI) Turbine (E41-C002/1E41*TCI-002)

The applicant has stated that a single-failure-proof path to safe shutdown can be achieved in the event of HPCI turbine failure using the automatic depressurization system, low pressure coolant injection system, and core spray system. The staff would have been in agreement with this position; however on May 22, 1984, the applicant requested an exemption from GDC 17. In light of this exemption request, the staff reviewed the safety implications and reported on them in SSER 6. In Chapter 15 of SSER 6, the staff analyzed all pertinent accident sequences and determined that in assuming the occurrence of a seismic event, the staff also assumes loss of offsite power and onsite ac power. To meet the single-failure-proof criterion, the staff also assumes that the HPCI system will be operational. Therefore, the staff will require the applicant to seismically qualify the HPCI turbine before fuel load, and the license will be so conditioned.

3.10.2.6 Power Range Monitor Panel (H11-P608/1H11*PNL-608)

An erroneously high reactor power reading as a result of failure of this equipment is fail-safe because the control system will act to lower power. An erroneously low power reading could lead to control system commands to increase power. However, in this instance, there are single-failure-proof backup systems that will automatically scram the reactor. In particular, should reactor power increase to excessively high levels, scram will automatically occur on high reactor pressure. As a last resort, the main steam radiation monitors will automatically scram the reactor if they detect high radiation levels that might result from fuel damage caused by the excessive power excursion. Because of built-in redundancy and electrical safeguards, the chances of an erroneous power level reading are low. In addition to the above justification based on system function, testing performed to date indicates that the power range monitoring panel has been successfully qualified to meet the Institute of Electrical and Electronics Engineers (IEEE) standard 344-1971. A retest of the panel to the standards of IEEE 344-1975 is in progress.

On the basis of the above, the staff concludes that interim operation, up to 5% power, with the power range monitor panel not fully qualified is justified.

3.10.2.7 Invessel Rack (F16-E006/1F16*FAK-09)

The invessel rack is used during refueling only, as a convenient invessel storage area for fuel bundles. It is not used during the initial fuel loading. Ample time is available before the first refueling outage for the applicant to perform the required nonlinear analysis to qualify the Shoreham invessel rack to the seismic qualification review team (SQRT) criteria. Even if it is not qualified by the first refueling outage, refueling could proceed without the use of this rack.

The staff concludes that interim operation until the first refueling outage without the invessel rack completely qualified poses no safety hazard.

3.10.3 Other SQRT Open Items

The remainder of the open items identified in SSER 3 and 4 have been successfully resolved by the applicant as described below.

3.10.3.1 Updated Equipment Qualification Summary List

The applicant has been submitting the updated equipment qualification summary list for the staff's information on a monthly basis.

3.10.3.2 Qualification Documentation Filing System

In the submittal of October 7, 1983, the applicant reported that a permanent filing system at the site had been established that covers all the relevant balance-of-plant (BOP) documentation, such as test reports or summaries, including anomalies and their resolutions. The applicant also stated that detailed nuclear steam supply system (NSSS) qualification documentation has been delivered to the site for the permanent site file, to back up the NSSS equipment dynamic qualification summaries. The staff finds this permanent filing system acceptable.

3.10.3.3 Single Frequency/Single Axis Testing Method

The use of single frequency/single axis testing is generally not acceptable for qualifying equipment to seismic loads. However, as noted in IEEE 344-1975, this method may be used in certain specific cases. In particular, the method may be used if it can be shown that the equipment (1) has no resonances in the amplified region of the required response spectra, (2) has only one resonance, or (3) resonances that are widely spaced and does not interact to reduce the fragility level.

The method applies to three cases, as discussed in the applicant's June 6, 1983, submittal. Single frequency, single axis tests were conducted for

- local panel devices, B21-N055 (163C1292)
- transmitter gage pressure (163C1564)
- Limitorque actuator recirculation discharge valve, B31-F031

The applicant's transmittal dated June 6, 1983 ("Technical Justification of the Single Frequency/Single Axis testing Method, Shoreham Nuclear Power Station"), clearly establishes the justification for the use of this method for these three pieces of equipment. In each case, the applicable response is cited in accordance with IEEE 344-1975. The use of single frequency/single axis testing is, therefore, acceptable for these equipment items.

3.10.3.4 Field Modifications on Already Qualified and Installed Equipment

The applicant submitted two lists of seismic Category I equipment change records--one for BOP equipment and one for NSSS equipment--with the June 28, 1983 letter. The lists include field modifications made to already qualified and installed safety-related equipment since the September 2, 1982 site SQRT audit. Additionally, the June 30, 1983, letter includes the installation modifications associated with the HPCI turbine qualification. It has been determined that all the modifications for this equipment cannot be completed before the plant exceeds 5% power (see Section 3.10.2.5 above). This information satisfies the staff request for the notification of field changes.

3.10.3.5 Cycling Effects of Hydrodynamic Loads on Equipment Qualification

The staff has accepted the approach adopted by General Electric (GE) in considering vibration fatigue cycling effects for NSSS equipment. At the staff's request, in a June 28, 1983 letter, the applicant submitted two sample calculations for the core spray motor and the residual heat removal (RHR) pump/motor. This information was reviewed by the staff and found to be acceptable.

In regard to the fatigue cycling effects for BOP equipment, the applicant has submitted Stone and Webster calculations for four components that were chosen on the basis of their location in areas of the plant where safety/relief valve (SRV) loads are known to be the most significant. These include a head tank, a loop level pump, a booster heat exchanger, and a Velan gate valve. The cumulative usage factors for all this equipment were found to be very small, with the largest 0.35 for the gate valve. The staff accepts the approach used by the applicant in calculating the usage factors.

The applicant has provided additional justifications for fatigue evaluation of components qualified by test. It was noted that, with few exceptions, fatigue testing has not been performed for Shoreham equipment. Instead, the durations in the seismic tests for one safe shutdown earthquake (SSE) and five operating basis earthquakes (OBEs) tests have been increased to 30 seconds each to account for additional SRV cycles. The amplitude and frequency content of test acceleration inputs bound Shoreham requirements for combined seismic and hydrodynamic loads. To further quantify the number of equivalent SRV cycles achieved, an analysis of an actual Shoreham test acceleration time history has been performed. The applicant's letter of June 28, 1983, includes the justification for such an analysis. On this basis, the staff finds the applicant's justifications on cycling effects of hydrodynamic loads acceptable.

3.10.3.6 Age-Sensitive Equipment

In regard to operability assurance for age-sensitive equipment, the applicant submitted information in letters dated March 17 and April 22, 1983 ("Surveillance and Maintenance Program Description") and sample procedures for batteries and pump motors. The staff has reviewed these submittals and has found the applicant's program adequate to ensure a qualified status of the equipment throughout the plant life. Therefore, this program is acceptable.

3.10.3.7 Emergency Switchgear

On February 23, 1983, the SQRT reviewed the 480-V emergency switchgear bus 112 test report in a meeting at Brown Boveri Electric, Spring House, Pennsylvania. All the staff's concerns relative to potentially undocumented anomalies were resolved, and the corresponding equipment-specific open item identified in SSER 3 is closed.

3.10.3.8 Confirmatory Items

In letters dated February 18 and April 15, 1983, the applicant submitted information on the open items listed below, which are confirmatory. The staff has reviewed these items and considers them resolved.

- A "road map" report describing the BOP equipment qualification methodology has been prepared and placed in the permanent plant SQRT file.

- Clarification of the worst case spectrum for floor-mounted equipment has been incorporated into the appropriate SQRT documentation packages.

- The confirmatory spectrum for floor-mounted equipment in the reactor building has been incorporated into the appropriate SQRT documentation packages.

- Current qualification levels for all motor-operated valves on the 30 piping subsystems discussed in SSER 3 were found to be larger than the acceleration levels calculated for the generic long-term program (LTP) confirmatory hydrodynamic loads. In addition, all pipe-mounted equipment on elevations 21, 83, and 106 feet has been identified. A 100% confirmatory evaluation has been completed, and, in all cases, components that were designed to the original Shoreham design-basis load definition were found to have adequate design margins to accommodate the LTP confirmatory loads.

3.10.4 Summary

The applicant has made significant progress toward completing the equipment seismic and dynamic qualfication program. However, before the program can be considered complete, the applicant must complete the seismic and dynamic qualification for the HPCI turbine before fuel load, and for the Class 1E cabinets and internals, auxiliary pump skids, and SDV vent and drain valves before the plant exceeds 5% power operation. The applicant must also complete the qualification for SDV solenoid valves before full power range testing during the power ascension program. Finally, qualification of the invessel rack must be complete before the first refueling outage.

The applicant will continue to provide a monthly updated equipment qualification summary list until this equipment has been qualified.

3.11 Environmental Qualification of Electrical and Mechanical Equipment

3.11.1 Background

SSER 3 identified several issues relating to justifications for interim operation with equipment that is not fully qualified and to qualification of the GE 200 series electrical penetrations that required resolution before an operating license is issued. On February 22, 1983, a new rule, 10 CFR 50.49, became effective that defined requirements for the environmental qualification of electrical equipment important to safety; this rule imposed several new requirements that applicants must address before licensing. The following paragraphs describe the staff evaluation of the applicant's responses to these outstanding items and to the new rule, and describe the staff's bases for concluding that the applicant has demonstrated conformance with 10 CFR 50.49.

3.11.2 Outstanding Items from SSER 3

3.11.2.1 Justification for Interim Operation

SSER 3 identified a number of open items relating to the justifications for interim operation (JIOs) with equipment that is not fully qualified. Many of these were requests for backup documentation used to support statements made in the JIOs or other minor clarifications. These have been resolved as a result of information in a letter from the applicant dated February 18, 1983 (SNRC-838), with the exception of the Anaconda flex conduit.

The applicant indicated that this item had been "successfully tested to the applicable service conditions." In a meeting with the applicant on July 29, 1983, the staff reviewed the qualification file for this item. Although a test report was available, the test was inadequate because only the electrical continuity of an assembly consisting of a junction box, conduit, and terminal blocks was measured during exposure to steam. The insulation resistance of the assembly, which could be reduced to unacceptable values for some instruments by failure of the plastic sleeve on the flexible conduit, was not measured. The applicant had performed additional analysis to demonstrate that the conduit construction is adequate for preventing moisture intrusion during a pipe break outside containment. The staff finds this acceptable only for justifying interim operation until additional type testing can be completed.

The applicant's original justification for interim operation was unacceptable because nonconservative handbook temperature ratings for the plastic sleeve of the conduit were used. As a result, the staff required that the applicant review all JIOs to determine if similar practices were utilized on other equipment items. The few cases where this method was utilized were found to be acceptable by the applicant and were so verified by the staff.

3.11.2.2 Interim Operation

The staff also requested that the applicant define the periods of interim operation with mechanical equipment not fully qualified, as identified in a letter dated November 19, 1982. In SNRC-838 dated February 18, 1983, the applicant indicated that full qualification would be accomplished by the end of the first refueling outage. The staff finds this schedule acceptable.

3.11.2.3 GE Series 200 Penetrations

The staff identified two outstanding items relating to the qualification of the GE series 200 electrical penetrations. The applicant addressed these items in a letter dated January 21, 1983 (SNRC-821) as follows:

- Surveillance testing: The staff requested that the applicant commit to a program for periodically monitoring the electrical integrity of these penetrations so significant age-related degradation can be detected and appropriate corrective action taken before failures occur. In SNRC-821, the applicant described an acceptable program to be utilized for this purpose.

- I^2R heating: The applicant provided information to show that the I^2R heating during qualification testing was greater than the heating effect that could be experienced in service. The response is acceptable.

3.11.3 Conformance with 10 CFR 50.49

10 CFR 50.49 contains several provisions not previously addressed by the applicant in the NUREG-0588 qualification program. In letters dated June 24, August 3 and 15, and September 9, 1983, the applicant discussed the effect of the rule on the existing environmental qualification program. The staff evaluated this response for those areas where a change to the program could occur. The staff's evaluation follows.

3.11.3.1 Scope of Equipment

10 CFR 50.49(b) and (c) define the scope of equipment to be included in the environmental qualification program. 10 CFR 50.49(c) limits the scope of equipment to that located in the harsh environments produced by design-basis events (DBEs) that is, therefore, susceptible to common mode failures.

Thus, a large portion of the electrical equipment important to safety is not covered by the rule and is not evaluated in this report. Conformance with existing requirements--such as the General Design Criteria (GDC, in Appendix A to 10 CFR 50), Appendix B to 10 CFR 50 (particularly Section III, "Design Control") and Regulatory Guide (RG) 1.33, Revision 2 ("Quality Assurance Program Requirements (Operation)") and other regulatory guides--is sufficient to ensure that electrical equipment located in mild environments performs adequately. The staff evaluation of this equipment is a part of the overall evaluation performed in accordance with the Standard Review plan (SRP, NUREG-0800).

10 CFR 50.49(b)(1) requires that safety-related equipment* be included in the program. The definition of safety-related is consistent with that used in the environmental qualification program.

Safety-related equipment that is not required to function to mitigate an event that produces a harsh environment need not be qualified for that harsh environment, as stated and implied in 10 CFR 59.49(d)(1), (e)(1), and (e)(4), provided that failure of that equipment has no impact on plant safety. This requirement agrees with that defined in the equipment classifications of NUREG-0588, Appendix E, Items 2a, 2b, and 2c. These classifications were used in the development of the Shoreham environmental qualification program, with the exception of a broader scope of DBEs to be evaluated, as discussed later in this report.

10 CFR 50.49(b)(2) requires qualification of nonsafety-related equipment whose failure could prevent the satisfactory accomplishment of safety functions by the safety-related equipment. The applicant has indicated that no Shoreham equipment is in this category. The applicant has referenced the control systems failure study, the high energy line break/control system failure analysis, and the electrical isolation design philosophy at Shoreham, which comply with RG 1.75, Revision 1.

The review of the first two areas is discussed in SER Section 7.7. The staff review has now been completed, and all issues have been satisfactorily resolved.

Position C.4 RG 1.75, Revision 1 states

> Associated circuits installed in accordance with Section 4.5.1 [of IEEE Standard 384-1974] should be subject to all requirements placed on Class 1E circuits such as cable derating, environmental qualification (emphasis added), flame retardance, splicing restrictions, and raceway fill unless it can be demonstrated that the absence of such requirements could not significantly reduce the availability of Class 1E circuits.

Associated circuits are defined as non-Class 1E circuits (i.e., nonsafety-related circuits) that share power supplies, enclosures, etc., with Class 1E circuits or that are not physically separated from Class 1E circuits. Other non-Class 1E circuits are not connected to Class 1E power supplies or are electrically isolated from Class 1E supplies to prevent malfunctions in one section of a circuit from causing unacceptable influences in other sections of the circuit.

The staff finds that conformance with this standard is sufficient to demonstrate compliance with 10 CFR 59.49(b)(2). Other interactions between safety-related and nonsafety-related equipment are covered in parts of the SRP, including Sections 3.5.1, 3.5.2 (missiles), 9.5.1 (fires), and 3.6.1 (pipe breaks).

Operating plants licensed in accordance with safety classification criteria less definitive than those applied to recently licensed plants may contain improperly classified equipment that would be covered by 10 CFR 50.49(b)(2). However, the staff review of the classification of structures, systems, and

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*Safety-related equipment is defined as equipment that is relied on to remain functional during and following design-basis events to ensure certain safety functions.

components in Section 3.2.1 of the Shoreham Final Safety Analysis Report (FSAR) provides reasonable assurance that the equipment at Shoreham has been classified using the proper criteria.

The last type of equipment to be included in the environmental qualification program is the Category 1 and 2 instrumentation addressed in RG 1.97, Revision 2. The applicant has identified installed equipment in this category and provided justifications for interim operation with unqualified equipment. The staff has reviewed the identified items in the same way that other equipment in the program has been identified.

3.11.3.2 Scope of Design-Basis Events

10 CFR 50.49 requires that equipment be qualified for DBEs that produce a harsh environment, subject to certain limitations specified in 10 CFR 50.49(c). In accordance with Commission directives, the applicant based the Shoreham program on LOCAs and pipe breaks inside and outside containment only. The applicant also has reviewed additional events and their impact on the program, and described the results to the staff. Some events create environments that are different from normal plant operating conditions but that are not "significantly more severe" than the normal environment. Qualification in accordance with the new rule is not required because a harsh environment is not created. One event, control rod drop, results in a 6-month integrated gamma dose in the steam tunnel of 3.4×10^5 rems. Equipment required to mitigate this event and achieve shutdown is either (1) included in the applicant's existing environmental qualification program with operability required at significantly high radiation levels, or (2) located in a mild environment.

On the basis of its review, the staff does not require the applicant to change the harsh environment qualification program.

Instrument line breaks in the secondary containment have also been considered as a result of the rule, but these are enveloped by the breaks postulated in FSAR Appendix 3C.

3.11.3.3 List of Equipment

10 CFR 50.49(d) directs applicants to prepare a list of equipment covered by the rule. The applicant provided this list to the staff, and the latest revision (in the applicant's June 27, 1983 letter (SNRC-917)) is acceptable.

3.11.3.4 Completion of Qualification

Previous staff evaluations indicated that a license condition would be imposed requiring full qualification by the end of the first refueling outage. However, because 10 CFR 50.49(g) does not specify schedule requirements for holders of operating licenses, the following license condition will be imposed on the applicant and will supersede the previous commitment:

> The applicant shall environmentally qualify all electrical equipment within the scope of 10 CFR 50.49 in accordance with the implementation requirements of 10 CFR 50.49(g).

All other requirements in the rule are bounded by the existing qualification program. The staff, therefore, finds that the applicant conforms with 10 CFR 50.49.

3.12 Reactor Building Internal Flooding

The staff has completed its review of the internal flooding analysis in the Shoreham probabilistic risk assessment (PRA) study and the Shoreham flooding submittal dated December 2, 1982.* The applicant had found the Shoreham core vulnerable frequency initiated by flooding to be about 4×10^{-6} per reactor-year.

For the most part, the staff found the assumptions and methodology used by the applicant to be reasonable. However, in its review, the staff used more recent licensee event report (LER) data and used a different model in re-evaluating the flood-initiating frequency. The staff model used a Markov process model to determine the frequency of flood precursor events, and used time-phased event trees to account for the effects of flooding to different levels.

The staff recognizes that there are many uncertainties in the analysis, particularly the human error in initiating a flood and in not taking proper corrective actions during a flood. Therefore, the staff has performed an uncertainty analysis using the SAMPLE program (NUREG-75/014). The staff estimates that the mean value of the core vulnerable frequency of accidents initiated by flooding in the reactor building at Shoreham is 2×10^{-5} per reactor-year, and the 95% upper limit is 7.5×10^{-5} per reactor-year. The core vulnerable frequency as a result of maintenance-induced flooding has a mean value of 7×10^{-6} per reactor-year, while the corresponding value for pipe break-induced flooding is 1.3×10^{-5} per reactor-year.

The staff's complete evaluation is in Appendix A of this report, which includes the evaluation of the applicant's PRA study on flooding performed by personnel at Brookhaven National Laboratory (BNL).

On the basis of its review, the staff concludes that although there are discrepancies between the applicant's core vulnerable frequencies and those determined by the staff, this item is satisfactorily resolved. The staff review has determined that this issue provides no basis for further investigation or for the denial of an operating license.

3.13 Long-Term Operability of Deep Draft Pumps

Bulletin IE 79-15 (dated July 1979), issued by the NRC office of Inspection and Enforcement (IE) (IEB 79-15), identified problems with deep draft pumps in operating facilities. These vertical turbine pumps are usually 30 to 60 feet long with impellers in casing bowls at the lowest elevation of the pump and the motor (driver) at the highest elevation; the discharge is just below the motor. This configuration has experienced excessive vibration and bearing wear, which have been attributed to

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*See Appendix A.

- flexibility of the rotor and casing structure
- natural vibration frequencies near the operating speed of the pump
- flow inlet conditions conducive to the formation of vortices at the bellmouth of the pump
- misalignment between the shaft and column

These conditions can cause and aggravate vibration-induced wear of the pump components, suggesting that these pumps might not be able to perform their required functions during or following an accident.

By letters dated October 13, 1981 (SNRC-626), April 15, 1983 (SNRC-857), and August 11, 1983 (SNRC-950), the applicant responded to IEB 79-15. The applicant stated that four such pumps are used in safety-related applications at Shoreham. These pumps are in the service water system and are required during normal operation. Unlike the emergency core cooling system (ECCS) pumps cited in IEB 79-15, the Shoreham deep draft service water pumps will experience extended, continuous operation. In addition, in support of the preoperational testing program, each pump has run more than 3000 hours without excessive bearing wear, under conditions that are representative of what the system will experience during power operation.

In accordance with Station Procedure 24.122.01 (Revision 2) and Revision 3 of the pump and valve inservice testing (IST) program, the pump vibration readings will be logged quarterly and compared to a baseline measurement to determine if any action is required. To ensure a repeatable reference vibration level, the baseline and subsequent vibration measurements are taken during stable operating periods, as specified in Section XI, Paragraph IWP-3500, of the Boiler and Pressure Vessel Code of the American Society of Mechanical Engineers (ASME Code). Pump flow rate inlet pressure and differential pressure are measured and compared to reference values to verify stable operation of the pump.

In addition to the quarterly tests, the service water pumps are continuously monitored for excessive vibration. Control room alarms activate whenever the measured vibration exceeds either the predermined "alert" or "warning" levels. The proper setpoints for these alarms will be considered during the staff review of the applicant's IST program.

The staff also reviewed Station Procedure 35.122.01 (Revision 1), which requires the pumps to be hand-turned following reassembly to ensure that no major misalignments exist. When the pumps return to service, if pump vibration exceeds either the warning or alert levels, the pump will be immediately shut down to determine the cause of the excessive vibration.

The pump shaft is guided by cutless rubber bushings at a maximum spacing of 80 inches. Journal bearings are located at the discharge head and at the lowest point on the pump shaft. Those bearings directly above and below each of the two impellers prevent the pump impellers from experiencing undesirable lateral deflection during operation.

In addition, the service water pumps have been designed to operate continuously for extended periods of time in the environment of the intake bay. System design features include traveling screens, which are used to prevent large, potentially damaging particles from entering the pumps, and hard-faced journal-bearing sleeves and bushings to enhance wear resistance.

On the basis of the above consideration and on the fact that the continuous vibration monitoring system has not shown any indication of potential problems as a result of shaft deflection or vibration on any of the service water pumps, the staff concludes that the applicant's long-term operability assurance program for deep draft pumps is acceptable, and IEB 79-15 is closed for Shoreham.

4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.4 Seismic and LOCA Loadings

The staff has approved the GE Topical Report NEDE-21175-3 (letter from C. O. Thomas (NRC) to J. F. Quirk (GE), October 20, 1983), which describes an analytical method for evaluating seismic and LOCA loads. The staff has reviewed the plant-specific values of liftoff and acceleration. The results of the review show that the vertical liftoff is insignificant, and the accelerations are within the evaluation-basis limits, thereby ensuring structural integrity and control rod insertibility during seismic and LOCA events. Therefore, the staff concludes that the confirmatory issue of seismic and LOCA loadings is resolved for Shoreham.

4.5 Reactor Materials

4.5.2 Reactor Internal and Core Support Materials

Board Notification 82-70, dated July 20, 1982, noted an NRC staff member's differing professional opinion (DPO) concerning the adequacy of welding procedures used during the fabrication of reactor vessel internals for boiling water reactors (BWRs). The DPO indicated that in fabricating such components, GE (and/or its subcontractors) had used welding procedures that permitted heat input levels that could cause "sensitization" of heat-affected zones of type 304 stainless steel, which is not consistent with RG 1.44. The intent and purpose of that guide is to ensure a low probability of intergranular stress corrosion cracking (IGSCC). One of the three factors necessary to produce IGSCC is sensitization of materials. Accordingly, prevention of sensitization is desirable.

The concerns identified in Board Notification 82-70 may be significant because the potentially sensitized components may include feedwater spargers, core spray spargers, the steam dryer, the shroud head and separator assembly, the jet pumps, the upper core support grid, the lower core support gird, the shroud support, the control guide tube, and control rod housings. Some of these components have cracked in service, and it is possible that such failures could have an adverse impact on the safety of the Shoreham plant. Broken component parts could interfere with the flow and distribution of cooling water. Loose parts could also damage fuel rods, interfere with the operation of control rods, and, in extreme cases, penetrate the reactor coolant pressure boundary through wear or internal damage.

The NRC staff member who filed the DPO visited the GE office in San Jose, California on September 22 and 23, 1982; the staff member also reviewed the Monticello plant inservice inspection records for the reactor internals at the offices of Northern States Power in Minneapolis, Minnesota on October 20, 1982.

Between these two visits, the staff member met with other staff members to discuss the information reviewed in San Jose. The staff member concluded that the procedures used in the fabrication of the reactor internals for Shoreham and other BWRs increased the susceptibility of weldments to IGSCC because of weld sensitization.

After the review of the Monticello inservice inspection (ISI) records, the staff member concluded that the technique used in the reactor internals ISI program being conducted at the plant would provide a resolution that would permit meaningful detection of significant inservice degradation of these components. The staff member also concluded that, given this technique, a scope of inspection based on that identified in the Monticello program and in Section 5.2.3.2.1.3 of the Preliminary Safety Analysis Report (PSAR) for the Perry plant (Docket 50-440) would resolve the concern relating to the potential inservice degradation of reactor internals for Shoreham.

Other NRC staff members have reviewed the question of whether implementation of the Monticello inspection technique in NRC licensing reviews would involve imposing any new requirements. The staff has determined that meeting the intent of ASME Code Section XI would necessitate the use of an inspection technique and scope consistent with the Monticello inspection program and that characterized in Section 5.2.3.2.1.3 of the Perry PSAR. This has been the position of the staff for some time; criteria on adequate inspection techniques that are similar to those used at Monticello were issued in IEB 80-13 on May 12, 1980.

By letter dated January 28, 1983, the applicant agreed to develop and incorporate into the Shoreham ISI program provisions involving (1) use of the Monticello-type techniques for detection of IGSCC, and (2) an inspection program scope consistent with that in Section 5.2.3.2.1.3 of the Perry PSAR. The Shoreham ISI program will be submitted to the staff, which will monitor implementation of the program as part of the staff's normal inspection functions pertaining to the ISI program. The applicant also agreed to notify the staff of any significant or substantive changes in the intended inspection program, and will continue to evaluate and implement, where practicable, state-of-the-art improvements in scope or methods of implementing the ISI program throughout the life of the plant.

On the basis of these commitments, which will be incorporated into a license condition, the staff considers the issues raised in the DPO resolved.

5 REACTOR COOLANT SYSTEM AND CONNECTED SYSTEMS

5.2 Integrity of the Reactor Coolant Pressure Boundary

5.2.6 Reactor Coolant Pressure Boundary Materials

5.2.6.2 Stainless Steel Pipe Cracking

In SSER 1, the staff concluded that the modifications performed by the applicant to stainless steel piping and the augmented inspection programs to be implemented are acceptable in accordance with NUREG-0313, Revision 1, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping."

Revision 2 to NUREG-0313, which is in preparation, will address the staff's technical positions on material selection and processing for prevention of IGSCC in stainless piping systems and on inspections of those systems that do not conform to the technical positions on materials selection and processing.

It is anticipated that the requirements of NUREG-0313, Revision 2, will be implemented uniformly on all BWR plants within 1 year. At that time, Shoreham and all other BWRs that have not been reviewed in detail will be evaluated. It should be noted that Shoreham conforms to the staff's technical positions in the proposed Revision 2 of NUREG-0313 on materials selection and processing to a greater extent than do most other operating BWRs.

The applicant has taken action to mitigate IGSCC in most weld joints, and has committed to augmented inservice inspection of those welds for which no mitigation actions have been taken. Shoreham has had little or no time at elevated temperatures, and accordingly, IGSCC is not anticipated. Therefore, the staff concludes that operation through at least the first refueling outage is acceptable.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

6.2.1.8 Pool Dynamics

E. Bulk to Local Temperature Differences

In SSER 1, the staff discussed the use of tests at the LaSalle Nuclear Power Station to establish the difference between local and bulk suppression pool temperatures to demonstrate that the maximum local pool temperature specification would not be exceeded. The staff required that the applicant demonstrate the applicability of the LaSalle tests to Shoreham and submit the results of this study to the staff before fuel load. By letter dated November 17, 1983 (SNRC-982), the applicant submitted the Shoreham-specific "Suppression Pool Local to Bulk Temperature Difference Report." The staff is reviewing this submittal in conjunction with reports from LaSalle, and will issue an evaluation later. The requirement to submit the report is therefore considered fulfilled.

6.2.7 Mark II Hydrodynamic Load Building Response

On September 27, 1982, the applicant reported an error in the GHOSH computer program that had been used in the analysis of the Shoreham Mark II containment. In assessing the impact of the error, another error in data transmittal from Stone and Webster Engineering Corporation (SWEC) to GE was discovered; this was reported on February 15, 1983. SWEC is the architect/engineer for Shoreham, and GE is the NSSS supplier. According to the applicant's report, the GHOSH program--which is a commercially available, finite element program--was used at Shoreham in the development of the building response spectra for Mark II hydrodynamic loads.

The first discrepancy was in an internal subroutine that calculates stiffness matrices for triangular finite elements. The program internally breaks each triangular element into three subsections to determine the centroid of the element and the overall stiffness. In doing this, the subroutine incorrectly ignored the stiffness of two subsections, assigning the stiffness of one subsection to the entire triangular element. This tends to present a lower relative stiffness than actually exists. These triangular elements were used in combination with rectangular elements in modeling the soil beneath the reactor building. No triangular elements were used in the superstructure.

In assessing the effect of the GHOSH discrepancy, SWEC discovered a second discrepancy, which was the incorrect labeling of the units for the rocking acceleration data and the corresponding response spectra transmitted to GE. This discrepancy was also found to apply to the confirmatory spectrum transmitted to GE in 1981. In these transmittals to GE, some of the units for rocking acceleration were specified in g values (g represents the gravitational acceleration equal to 32.3 feet per second per second), whereas some of the plots of the rocking data were labeled in radians per second per second. GE had incorrectly utilized the units of radians per second per second in the Shoreham Mark II confirmatory analyses. The correct units are g per foot for rocking acceleration. This discrepancy affected only the GE scope of work because the rocking time history was used only in the NSSS evaluation.

After the discovery of the two errors, SWEC and GE assessed the effects of these two errors on the design of structures, components, and systems. The results of this assessment were described in a report forwarded by letter from M. H. Milligan (LILCO) to James M. Allan (NRC), dated April 20, 1983 (SNRC-875). The assessment procedure as implemented by the applicant can be summarized as follows:

(1) The GHOSH program was revised.

(2) Representative sets of input pressure time histories for each type of pool dynamic loads were selected for use in the assessment.

(3) Amplified response spectra (ARS) were generated using the revised GHOSH program and the selected representative time histories as indicated in (2) above, and the rocking units were corrected.

(4) The adequacy of all components and structures was assessed by comparing the revised confirmatory ARS generated from (3) above with (a) the old confirmatory ARS and (b) the design-basis ARS. Both of the latter ARS were generated by using the original GHOSH program. The design-basis ARS were generated using the pool loads established in the lead plant acceptance criteria (LPAC) and the old confirmatory ARS were generated using pool loads approved by the staff. These pool loads were used to assess and confirm the adequacy of components and structures designed on the basis of LPAC loads.

(5) Scaling factors were generated for design parameters (loads and responses) at critical points to be used for assessment of the design of the reactor pressure vessel (RPV) and its internals and piping.

(6) An assessment was conducted on the basis of resultant stresses from load combinations as described in the Shoreham Mark II design assessment report (DAR), when the revised loads exceeded the design loads.

(7) For equipment qualified by test, the required response spectra (RRS) (which are obtained by combining the revised confirmatory response spectrum and the applicable seismic response spectrum) were compared with the test response spectra (TRS). To demonstrate that the equipment is qualified, the TRS should envelope the RRS.

On the basis of the results of the assessment outlined above, the applicant concluded that no changes to the Shoreham plant design are warranted because of the two discrepancies.

The staff has reviewed the assessment procedure and agrees with the applicant's conclusion. The staff finds the conclusion reasonable because

(1) The GHOSH program is not used in the seismic analysis, but only in the analysis of hydrodynamic loads.

(2) The discrepancy in the GHOSH program incorrectly reduces the stiffness of the foundation soil, which would result in lower fundamental structural frequency and amplitude. Therefore, the revised GHOSH program should result in frequency shift and some amplitude increase.

(3) The design-basis loads that were used in the containment system design have been established generally on a more conservative basis than those loads determined from the MARK II long-term program that were accepted by the staff and used in the confirmatory evaluation.

(4) The discrepancy in the unit for rocking motion (acceleration) is limited to the NSSS supplied by GE. Because the NSSS is located in the lower level of the containment, the effect of the error on the NSSS is slight.

(5) The pool dynamic loads are only one load component in a load combination, and any change in their magnitude would have limited impact on the load combinations.

Even though the two discrepancies have not resulted in any change to the containment system and its components, the staff had some concerns about the adequacy of the quality assurance in design. In response to staff's concerns, the applicant stated that because of the uniqueness of the discrepancies in nature and cause, they should not be considered as indicators of any programmatic weakness in the design of the quality assurance program. Moreover, the GHOSH program has been validated through the use of ANSYS computer program, and the applicant has instituted precautionary measures to prevent the recurrence of the data transmittal error.

On the basis of its review and evaluation of the information provided by the applicant, the staff concludes that the issues arising from the errors in the GHOSH program and in the transmittal of the rocking data have been satisfactorily resolved.

7 INSTRUMENTATION AND CONTROLS

7.3 Engineered Safety Feature Systems

7.3.1 Low Pressure Coolant Injection System Modifications

As part of their inspection activities, NRC staff inspectors reviewed information provided by the applicant regarding the lack of annuciation for the low pressure coolant injection (LPCI) low pressure permissive interlock for the injection valve opening. The inspectors concluded that the Shoreham design did not meet the requirements for IEEE-279 (memorandum from Themis P. Speis to Thomas Novak, November 30, 1982).

Paragraph 4.19 of IEEE 279 requires that protective actions be indicated and identified down to the channel level. It was the staff's position that to meet Paragraph 4.19, the actuation of the low pressure permissive relay (410 psig) for the LPCI valve should be indicated or annuciated in the control room. Thus, the staff required the applicant to modify the design.

In a letter dated February 8, 1983, from J. L. Smith (LILCO) to Harold R. Denton (NRC), the applicant stated that the LPCI low pressure permissive relay will be annuciated at panel 1H*PNL601 on annunciation boards A-1 (System A) and A-2 (System B). These annuciators have been located in accordance with good human engineering practices and will be installed before fuel load. The staff has reviewed the applicant's response to this concern and has concluded that the design meets IEEE 279. Therefore, this issue is resolved.

7.3.6 Loss of Safety Function After Reset

As was done for operating reactors through IEB 80-06, the NRC staff requested that the applicant review all safety equipment to determine which, if any, safety functions might be unavailable after reset, and what changes could be implemented to correct any problems. This review was to follow the following guidelines:

(1) Review the drawings for all systems serving safety-related functions at the schematic level to determine whether or not upon the reset of an engineered safety feature (ESF) actuation signal (ESFAS), all associated safety-related equipment remains in its emergency mode.

(2) Verify that the actual installed instrumentation and controls at the facility are consistent with the schematics reviewed in item (1) by conducting a test to demonstrate that all safety-related equipment remains in its emergency mode upon resetting of the ESFAS.

(3) If any safety-related equipment does not remain in its emergency mode upon reset of the ESFAS, describe the proposed system modification or provide acceptable justifications.

The applicant responded to this concern by letter dated March 18, 1981 (SNRC-546). The staff review of this response, which is in SSER 1, concluded that use of an ESF reset control would not result in the loss of safety functions at Shoreham. Therefore, the staff considered this concern resolved. However, as a result of review of the Shoreham ESF reset designs by the NRC Region I staff, apparent discrepancies were discovered in the results of the applicant's review regarding this concern. Because of these apparent discrepancies, the staff questioned the validity of the applicant's original ESF reset review and the basis for the conclusions. The staff determined that this concern needed further review, and transmitted additional questions to the applicant.

The applicant's response to the first question (FSAR Revision 26, April 1982) provided an acceptable clarification of the discrepancies noted, with the exception of the control room air conditioning (CRAC) system. The discrepancies noted in the inspection report (excluding CRAC) involved apparent reset problems in the Shoreham fire protection system and in nonsafety-related equipment that changed its mode or position to the normal state after actuation, as a result of a manual reset operation. The intent of IEB 80-06 is to address the operation of ESF systems and to determine which, if any, safety functions might be unavailable after an actuation signal reset. The staff had concluded that the discrepancies noted (excluding CRAC) involved systems that are not ESF systems, and, therefore, need not be addressed in this context.

For the CRAC system, the applicant's response indicated that valves in the system would revert to a normal position if switch 1A2 were reset, but that this would occur only if the CRAC system were manually and not automatically initiated. The staff questioned the applicant (Question 223.100) regarding the adequacy of the review for manual initiation and the subsequent reset thereof for all of the ESF systems.

The applicant's response to this question (FSAR Revision 28, December 1982) stated that the reviews regarding this concern included manual as well as automatic actuation of the ESF systems. The response also provided additional information regarding the automatic and manual actuation capabilities of the CRAC system. When required to perform its intended protective function, the CRAC system is automatically initiated, and distinct and deliberate operator actions are required before any component can return to its normal mode. If the CRAC system is manually initiated and an automatic initiation signal is subsequently received, the automatic signal takes precedence. A system manual actuation through switch 1A1 does enable a system reset through switch 1A2 (assuming no automatic actuation takes place). Reset through switch 1A2 would require deliberate operator action and would not affect any system other than the CRAC system. In addition, reset through switch 1A2 would have to occur individually for each train of the CRAC system (two independent deliberate operator actions).

The staff reviewed the instrumentation and control schematics for the CRAC system and concluded that the design adequately met the staff guidelines on ESF reset controls and that the ESF reset control concern was resolved.

However, the applicant was required (as specified in IEB 80-06) to perform a preoperational test to demonstrate that all ESF equipment (except the systems for which acceptable justifications have been provided) remains in its emergency mode upon removal of the actuation signal and/or resetting of the various isolation or actuation signals. During the preoperational test, an NRC inspector discovered two additional apparent discrepancies: (1) the reactor building standby ventilation system (RBSVS) changes to the nonsafety mode upon reset from manual initiation and from a low differential pressure initiation, and (2) the traversing incore probe (TIP) nitrogen purge containment isolation valve reopens after a reset of the nuclear steam supply shutoff system (Inspection Report 50-322/83-08, April 15, 1983). The inspector also noted that the preoperational test did not fully verify that components did not change position after the actuation signal clears and after a system reset from both automatic and manual initiations.

The applicant responded to these concerns in a letter from J. L. Smith to Harold R. Denton dated June 8, 1983. In this letter, the applicant stated that originally the term "ESF actuation signal" was utilized in a narrow context. In an effort to resolve the ESF reset concern, the applicant conducted an additional engineering review based on a broader definition of ESFAS and included

(1) ESF systems actuated by ESFAS and affected by a reset of these signals

(2) ESF systems actuated by non-ESF actuation signals and affected by subsequent reset of these signals

(3) non-ESF systems affected by resets of ESFAS

This additional engineering review identified four possible problem areas (including the two discrepancies noted by Region I) as follows:

(1) Steam Condensing Mode of RHR

This mode is used after the primary heat sink is isolated. It takes steam from the reactor, reduces the pressure, and directs it to the RHR heat exchangers where it is condensed. The condensate is then returned to either the reactor pressure vessel via the RCIC system or to the suppression pool. Upon an ESFAS, steam inlet valves 1E11*MOV-043A and B and pressure control valves (PCVs) 1E*PCV-003A, B, 007A, and B close. When the ESFAS is reset, the PCVs will reopen, but the steam inlet valves and the condensate return valves will remain closed. This resetting sequence will occur only if the steam condensing mode is in service at the time of the ESF actuation.

The staff has concluded that this method of operation meets the intent of IEB 80-06, and no modifications are required.

(2) TIP System

The TIP system is used to map the core. It consists of four movable detectors, four drive mechanisms (each with ball and shear valves for containment isolation), readout equipment, and indexing equipment. If the probes are inserted at the time of an ESFAS, they would be withdrawn. A reset of the actuation signal would cause the probes to be reinserted. This would occur only if the TIP system were in use at the time of ESF actuation. The applicant has stated that a design modification is being pursued that will preclude reinsertion of the TIP probes upon reset of the ESFAS. Because of the post-fuel load modifications and the 20- to

30-week lead time needed for this design modification, the modification is expected to be completed by the last quarter of 1984.

The staff has concluded that interim operation until the first refueling shutdown without the design modification is acceptable because (1) there is a low probability of the TIP system being in operation concurrent with an ESFAS and its subsequent reset (it is in operation only 2% of the time when a plant operates at power), and (2) even if this occurred, the leakage from an unisolated TIP would be within the guidelines of Title 10 of the Code of Federal Regulations (10 CFR 100). However, the license will be conditioned to require the applicant to modify the design before startup after the first refueling to prevent reinsertion of the TIP probes upon reset of an ESFAS, thereby meeting the recommendations of IEB 80-06.

In addition, the applicant stated that the solenoid valve for the TIP nitrogen purge line (upstream of isolation valve 1C51*SOV-028) will reopen upon reset of the ESFAS. However, the isolation valve will remain closed. The staff has concluded that this method of operation meets the intent of IEB 80-06, and no modifications are necessary for the nitrogen purge line solenoid valve.

(3) RBSVS and CRAC

The RBSVS initiation and reset design is similar to the CRAC design discussed previously. However, the applicant modified the original submittal (FSAR Revision 28, December 1982) regarding the CRAC system by stating that reactor building low differential pressure is an actuation signal that, upon reset, would enable CRAC components to change state by reverting to their normal mode. The RBSVS and CRAC start automatically on the following signals:

- reactor vessel water level low (1)
- drywell pressure high (2)
- reactor building refueling air exhaust duct radiation high (3)
- bus under voltage (RBSVS only) (4)
- reactor building low differential pressure (5)

If the RBSVS or CRAC system is automatically or manually actuated from the logics of signals 1, 2, or 3, the system components will not change position unless these signals are cleared, the initiating logic is reset, and the RBSVS and CRAC system logics are reset. If RBSVS and CRAC are started by signal 4 (RBSVS only) or 5, or manually initiated via the system switch, the system components will change position to normal upon a reset signal. The applicant has stated that this is acceptable because signals 4 (RBSVS) and 5 (CRAC and RBSVS) are operation-related and not accident-related signals. Therefore, the present reset design capability should be acceptable. For RBSVS manual initiation, reset would require deliberate operator action and would not affect any system other than the RBSVS. In addition, each train of the RBSVS (two independent deliberate operator actions) would have to be reset individually. The staff concurrs with the applicant's position regarding RBSVS manual actuation (CRAC system manual actuation was discussed above) and the automatic actuation (RBSVS only) through signal 4 (bus under voltage). However, the staff did not concur with the applicant's position regarding automatic actuation of RBSVS or CRAC system via signal 5. The staff concluded that signal 5 (reactor building low differential pressure) is not an operational actuation signal but is, in fact, an ESFAS and should be considered in accordance with IEB 80-06.

The applicant's response to this concern (FSAR Revision 32, November 1983) stated that for both RBSVS and CRAC system actuation by the reactor building low differential pressure signal, the system components would change position to normal upon clearing of the initiation signal and manual reset of the RBSVS and CRAC system logics, respectively. Thus, deliberate operator action independent of the clearing of the initiation signal is required. In addition, each train of the RBSVS and the CRAC system would have to be reset individually (two independent deliberate operator actions for each system).

The staff has reviewed the instrumentation and control schematics and the applicant's response to the staff questions regarding the RBSVS and CRAC system and concludes that the designs adequately meet the staff guidelines regarding ESF reset controls and the intent of IEB 80-06. Thus, the designs are acceptable.

(4) Automatic Depressurization System (ADS) Safety/Relief Valves

The resetting of the ESFAS will cause the ADS safety/relief valves to close if they are not already closed. The reset pushbuttons for ADS are provided as the means of manually preventing or limiting inadvertent actuation of the ADS. These are the only ADS shutoff switches available to the operator.

The applicant has taken the position that this design is consistent with IEEE standards and that no change is necessary to meet IEB 80-06. The staff concurs with the applicant's position.

With regard to preoperational testing, the applicant has committed to perform the preoperational test program specified in IEB 80-06 to verify that ESF system components (except those for which acceptable justification has been provided) do not change position upon removal of the ESFAS and/or a reset of the various isolation or actuation signals. Satisfactory completion of these preoperational tests will be verified by an NRC Regional Inspector.

The staff has reviewed the applicant's responses to the concerns expressed in IEB 80-06 and concluded that the Shoreham ESF actuation designs meet the staff guidelines regarding ESF reset controls. Therefore, the concerns expressed in IEB 80-06 are resolved for Shoreham. However, the applicant will be required, as a condition of the license, (1) to provide an acceptable reset design for the containment isolation provisions of the TIP system and (2) to have that revised design installed before startup after the first refueling.

7.3.10 Core Spray Valve Logic and Setpoint

As part of their inspection activities, NRC staff inspectors reviewed information provided by the applicant on core spray valve logic and setpoint data and determined (memorandum from Themis P. Speis to Thomas M. Novak, November 1982) that the present design is unacceptable for long-term operation at Shoreham.

The present design opens the loop injection valve (MOV-033) following actuation of a LOCA signal based on a differential pressure detector signal (PDS-033) across the valve itself. This signal opens the valve at 450 psid and is arranged in a simple one out of one logic. The core spray pump discharge pressure is 290 psig, and, together with the 450 psid setting of PDS-033, would allow MOV-33 to open at a reactor pressure of about 740 psig. The piping upstream of the loop injection valve is designed for 500 psig. If the loop injection check valve (1E26-F006 A or B) were to stick or leak, the core spray piping could be exposed to excessive pressures. On this basis, the staff has required that the applicant change the low pressure permissive interlock design to a design that would prevent overpressurization of the core spray piping, assuming a check valve failure.

In a letter from J. L. Smith (LILCO) to Harold R. Denton (NRC), dated February 18, 1983, the applicant committed to make these design changes before startup after the first refueling outage and to provide NRC the conceptual design for staff review before the modifications are implemented. The staff will require that this design change be implemented before startup following the first refueling, and the operating license will be so conditioned. In addition, until the core spray injection valve low pressure permissive interlock is modified during or before the first refueling outage, the staff will require that core spray system check valves 1E21-F006 A and B be demonstrated operable (in addition to normal surveillance requirements) by verifying leakage is within its limit

(1) whenever the unit has been in cold shutdown, after the last check valve disturbance (i.e., when the check valve has changed position) before the reactor coolant system temperature exceeds 200°F

(2) within 24 hours following check valve disturbance, except during cold shutdown

In a letter dated February 18, 1983, the applicant committed to these surveillance requirements. The staff has reviewed the applicant's response has concluded that this item is resolved. The license will be conditioned to require this testing until the design modification is acceptably implemented.

7.4 Systems Required for Safe Shutdown

7.4.3 Remote Shutdown System

On the basis of its review of the information furnished by the applicant regarding the remote shutdown panel (RSP), as described in Section 7.4.3 of SSER 3, the staff found that the design of the RSP would meet GDC 19 and SRP 7.4.II and III. As a confirmatory item, the staff required the applicant to provide final operating procedures and Technical Specifications and to perform a system operational verification test of the RSP with the assumption of the most limiting single failure in the equipment train controlled from the RSP or remote stations away from the RSP.

In a letter dated June 21, 1983, from J. L. Smith to Harold R. Denton (SNRC-909), the applicant committed to (1) conduct a walk-through before fuel load to demonstrate RSP system operability (including stations remote from the RSP) with the assumption of the most limiting single failure; (2) revise the operating procedures before exceeding 5% power to reflect the final design of the RSP and its remote stations; and (3) address the RSP and its remote stations in the Technical Specificatons.

As documented in inspection report 50-322/83-35 and reported an inspection report 50-322/84-10, the inspector watched the applicant perform a walk-through using the existing RSP system design to demonstrate that there are appropriate communcation and accessibility to remote operating areas, and that required equipment could be operated. This walk-through was performed assuming the single worst case failure had occurred. The inspector identified three concerns: the lack of a written procedure, the inaccessiblity of some valves, and missing valve tags.

To address these concerns, the applicant issued TP23.133.02, "Local Operation During Failure of Bus 102 at Remote Shutdown Panel," to document the performance of this walk-through. The inspector reviewed the completed procedure, which was performed on February 23, 1984, and noted that the procedure required the operators (1) to document the method of accessiblity to the valve to verify that the proper component tag was in place, and (2) to record the method of communication.

The inspector identified no discrepancies in the procedure. The inspector also reviewed the applicant's program for valve and component tagging and verified that an ongoing program was in place to ensure that all components are properly tagged. The applicant had adequately addressed the concerns of this unresolved item and had completed the walk-through committed to in SNRC-909.

On this basis, the NRC staff concludes that the applicant's commitment to items (2) and (3) is acceptable and that these confirmatory items are resolved. Item (1) is completed at this time.

The staff will condition the Shoreham license to require the applicant to (1) implement (and document) all of the required design changes discussed in Section 7.4.3 of SSER 3 by the end of the first refueling and (2) perform an acceptable procedure verification test for the new RSP design at that time.

The applicant indicated that this worst case failure was the loss of the Blue Emergency Bus (Bus 102) because of its associated loads.

13 CONDUCT OF OPERATIONS

13.3 Emergency Planning

The applicant's emergency plan was evaluated in SSER 1. SSER 1 identified deficiencies requiring revisions or additional information, and the applicant responded by providing the required information. The staff reviewed the information and published its findings in SSER 3, which identified open and confirmatory items not yet resolved. The staff has visited the reactor site and evaluated the applicant's progress in resolving the open and confirmatory items. This report discusses those items. The order of presentation corresponds to the listing of deficiencies in Section 13.3 of SSERs 1 and 3.

13.3.1 Assignment of Responsibility (Organizational Control)

SSER 3 identified the following open items:

(1) The New York State site-specific emergency plan for Shoreham is still under development and has not yet been formally submitted to the NRC.

(2) The Suffolk County Radiological Emergency Response Plan is still under development and has not yet been formally submitted to the NRC.

The Suffolk County authorities have decided not to participate further in offsite emergency planning, and the State of New York will not impose an independently developed plan on the local authorities. In the absence of state and local plans, the applicant has developed an offsite radiological emergency response plan for Shoreham, referred to as the LILCO Transition Plan, and the implementing procedures for this plan. The Transition Plan (Revisions 1, 2, and 3) has been submitted to the NRC and, at the request of the NRC, was reviewed by the Federal Emergency Management Agency (FEMA). FEMA provided its findings on Revision 3 to the Transition Plan by letter dated March 15, 1984. FEMA identified 32 plan inadequacies and raised concerns regarding the applicant's legal authority in certain areas of the Transition Plan. Since that time, members of FEMA and the staff met with the applicant to dicuss these inadequacies. As a result, the applicant submitted Revision 4 to this plan addressing FEMA's concerns. This revision is presently under review.

13.3.2 Emergency Classification System

SSER 3 documented the applicant's commitment that all remaining information on emergency action levels (EALs) would be submitted to the staff for review before fuel load.

In a submittal dated June 3, 1983, the applicant provided all the requested information on EALs. The staff has reviewed this information and finds that it complies with Appendix 1 of NUREG-0654. The staff concludes that this item has been satisfactorily resolved.

13.3.3 Notification Methods and Procedures

SSER 3 stated that the applicant plans to coordinate protective action recommendations with local and state emergency personnel when the offsite plans are available for review. As indicated in Section 13.3.2 of this report, county and state plans have not been submitted. The applicant has submitted a Transition Plan to compensate for this inadequacy; however, this is considered to be an open item pending the resolution of the offsite emergency preparedness issue.

13.3.4 Public Education and Information

SSER 3 identified lack of coordination with Suffolk County on the public information program as an open item.

Since January 1983, the applicant has been mailing to all electric service customers within the 10-mile emergency planning zone (EPZ) a monthly newsletter that provides generic information about emergency preparedness. The information provided in the newsletter to date has included a description of the alert and notification system including the siren system, tone alert radios, and the emergency broadcast system (station WALK); basic information about radiation; and information about evacuation. On February 17, 1984, the applicant submitted revision 3 of the public information brochure, which includes improved maps, additional information on the classification of radiological emergencies, and information for the hearing impaired and disabled.

The staff concludes that coordination with Suffolk County on the public information program is not presently feasible as a result of Suffolk County's refusal to participate in Shoreham emergency planning. However, on the basis of its review of the emergency planning information already distributed through the newsletter and its review of the public information brochure that the applicant plans to mail to all residents in the 10-mile EPZ, the staff concludes that the applicant has provided a satisfactory response to this item.

13.3.5 Emergency Facilities and Equipment

As documented in SSER 3, the applicant committed that the Technical Support Center, the Emergency Operations Facility, and the Operations Support Center would be functional before fuel load. The applicant also committed that the backup meteorological tower would be functional before fuel load and that agreements would be made with offsite agencies for seismic, meteorological, and hydrologic information.

On the basis of its review of information in the emergency plan, on the results of the emergency plan implementation appraisal conducted at Shoreham, and on observations made during visits to the Shoreham site, the staff finds that, on an interim basis, the emergency response facilities (ERFs) and equipment at Shoreham are adequate to support a response effort in the event of a radiological emergency. In addition, information obtained during the site visits has established that the backup meteorological tower is operational and that the applicant has made agreements with Lamont Laboratories for seismic information and with the National Weather Service for meteorological and hydrologic information. The staff concludes that this issue is resolved.

Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability" (issued via Generic Letter 82-33 dated December 17, 1982), provided additional clarification for items in NUREG-0737, "Clarification of TMI Action Plan Requirements," including ERFs. As indicated in Supplement 1 to NUREG-0737, the staff will conduct a post-implementation appraisal of the applicant's emergency response capability against the requirements specified in Supplement 1 to NUREG-0737, including the adequacy of the completed ERFs. The schedule will be developed between the applicant and the NRC.

13.3.6 Accident Assessment

As documented in SSER 3, the applicant has committed to complete installation of equipment necessary for radiological assessment.

On the basis of information obtained during the onsite emergency plan implementation appraisal and subsequent site visits, the staff has verified that the applicant has completed installation of radiation effluent monitors, inplant radioiodine instrumentation, and containment high-range radiation monitors. The applicant has also completed installation of a radiation monitoring system computer for computing offsite radiological consequences based on either measured or assumed radiation source terms and site meteorology. The staff finds that this issue has been satisfactorily resolved.

13.3.7 Protective Response

SSER 3 indicated that the applicant had committed to complete installation of equipment for respiratory protection before fuel load.

A facility for testing and fitting respirators and a refilling system have been installed on the site and are operational. In addition, implementation procedures have been written and approved by plant management. Thus, the staff finds that this item has been satisfactorily resolved.

13.3.8 Radiological Emergency Response Training

SSER 3 noted that the applicant had developed a training program for the Suffolk County Police, but the police had not responded to the applicant's offer to provide training.

The staff finds that the Suffolk County Police still have not accepted the training offered by the applicant. In the applicant's Transition Plan, during a radiological emergency at Shoreham certain police functions would be performed by applicant personnel, who are being trained to perform such functions. The staff considers that this item is related to offsite preparedness and will remain open pending resolution of the offsite emergency preparedness issue at Shoreham.

13.3.9 Emergency Plan Implementation Appraisal

During the period of August 23 to September 2, 1982, the staff conducted an onsite appraisal of the applicant's capability to implement the emergency plan. This appraisal was confined to elements of the Shoreham emergency plan (onsite) and did not address elements of the applicant's Transition Plan (offsite). The findings of the emergency preparedness appraisal and the applicant's commitment to resolve the deficiencies noted therein by specified times were transmitted to the applicant in a report dated September 13, 1982. In letters to the NRC dated October 29, 1982, February 14, 1983, and April 21, 1983, the applicant reported the progress in resolving the deficiencies. From December 5 to 9, 1983, the staff conducted an onsite reappraisal of the applicant's progress. The reappraisal report, dated February 6, 1984, identified four open items to be resolved. The applicant has made further progress in resolving these items, and the staff has determined that as of April 1, 1984, the status of open items was as follows:

(1) Four radiation monitoring system monitors remain to be calibrated.

(2) A replacement valve has been installed in the post-accident sampling system (PASS); the valve must be tested and calibrated.

(3) New York State must agree to the national warning system (NAWAS) and the radiological emergency communication system (RECS) telephone drops in the New York State emergency operations center (EOC).

(4) The audibility of the onsite public address system will be adjusted to the ambient noise level after the plant is in operation.

(5) The distribution of the public information brochure must be completed. The staff will request that the applicant distribute the public information brochure before fuel load.

The NRC reapprasial also determined that the applicant has completed a review and update of the emergency plan implementation procedures. The reappraisal also determined that the applicant has completed the installation, testing, and development of procedures for the following: the computerized dose assessment system; the radiation and effluent monitoring system (with the exception of the calibration noted above); emergency response facilities; decontamination facility; and EAL instrumentation set-points.

The staff has determined that resolution of the two remaining open items related to equipment--calibration of the remaining radiation monitor and the valve in the post-accident sampling system--can be confirmed through re-inspection before fuel loading. The other open items are related to the resolution of the offsite emergency preparedness issue.

13.3.10 Conclusion

On the basis of its review of information provided by the applicant, on the results of the onsite emergency plan implementation appraisal, and on additional staff visits to the site, the staff has determined that the state of onsite emergency preparednesss provides reasonable assurance that adequate protective measures can be taken in the event of a radiological emergency that may occur during fuel loading and low-power operations (up to 5% of rated power).

17 QUALITY ASSURANCE

17.7 Independent Design Review

Teledyne Engineering Services (TES) performed an independent design review (IDR) for the applicant on a portion of the low pressure core spray system (LPCS) to verify (1) that the design and quality assurance process imposed by documentation was adequately implemented and (2) that the as-built configuration was in compliance with the commitments in the FSAR.

In a letter from D. F. Landers (TES) to H. R. Denton (NRC) dated June 30, 1983, TES transmitted Technical Report TR-5633-3, "Executive Summary of Final Report - Independent Design Review for the Shoreham Nuclear Power Station," dated June 30, 1983. The final report transmitted to the staff was TES Technical Report TR-5633-4, "Final Report - Independent Design Review for the Shoreham Nuclear Power Station," dated July 22, 1983. The final report included the results outlined in the executive summary, all internal committee review forms, the TES additional concerns, disposition responses from the applicant, and final TES disposition reports.

17.7.1 Program Scope

The major areas of review were

- Task 1: design process and procedures
- Task 2: design requirements
- Task 3: as-built design documents
- Task 4: as-built plant configuration
- Task 5: as-built documentation vs. plant configuration
- Task 6: quality assurance process and documentation

Although the initial scope of the IDR was to review a portion of the LPCS system, during the review, the scope of the IDR was expanded to address a number of findings on a generic basis. The generic review covered the following areas:

(1) small bore piping
(2) attachment of supports to pipe
(3) consideration of time-history dynamic loading in piping and support design
(4) determination of applied accelerations on valve operators and comparison with allowables
(5) branch line stress intensification factors
(6) thermal attenuation modelling of tie-back supports
(7) adequacy of Vibra check baseplates in a radiation environment

The IDR focused on a specific time in the Shoreham design and construction process so deficiencies, the subsequent design changes, the reconciliation with other disciplines, and the final construction could be identified. As a result, TES was able to review the results of the total process as well as to review the ongoing design and construction process over approximately 13 months. About 12,000 hours were expended by TES in the performance of this IDR.

17.7.2 Results of the IDR

The IDR was performed in three phases. The first phase included a complete review of the design and quality assurance process. At the conclusion of this phase, 28 items had been identified and were classified as follows:*

- 2 closed
- 16 findings
- 10 observations

Phase 2 involved a review of the responses, prepared by the applicant and SWEC, to the 16 findings in Phase 1. As a result of this review, eight findings were closed and eight additional concerns were identified.*

Phase 3 involved a final review of each item for which an additional concern had been identified. This review included several meetings between LILCO, SWEC, and TES,** as well as the formal responses submitted by the applicant and SWEC. Phase 3 was completed when these eight additional concerns were closed. The results of the review are in TES Technical Report TR-5633-3.

17.7.3 TES Conclusions and Recommendations

In the area of quality assurance (QA), TES indicated that the applicant's QA program as applied to construction of the LPCS system demonstrates management awareness and participation and a high level of proficiency and efficiency in the QA organization, and exceeds the minimum in application and performance of the QA program requirements.

On the basis of the results of the IDR, TES found that the applicant has complied with the commitments in the FSAR with respect to design and QA.

The responses by SWEC to a number of the generic items were in the form of engineering studies or evaluations that differ from calculations in the SWEC design process. The term "calculation" denotes an engineering/design technical report that provides the basis for an engineered design or conclusion and provides the full and formal documentation of the engineering process. A "study" or "evaluation" serves to verify the conclusions of previously established calculations rather then replace them.

For example, SWEC performed an "evaluation" to determine the adequacy of valve operators to meet acceptable acceleration levels. Part of this study involved reanalysis of three piping systems using different modelling techniques, damping values, and/or acceleration summation. TES recommended that these analyses should eventually become part of the formal documentation for Shoreham. That is, the analyses should be modified so they can be classified as "calculations."

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*D. F. Landers (TES), letter to H. R. Denton (NRC), February 11, 1983.
**J. H. King (TES), letters to H. R. Denton (NRC), April 6 and 21, and May 6, 1983.

Further, TES recommended that the applicant review all the "studies" and "evaluations" performed as a result of this IDR to determine what existing "calculations" require modification to bring the formal documentation in line with the conclusions of this IDR. Not all of the "calculations" impacted by "studies" and "evaluations" will require modification, and reference to, or attachment of, the appropriate "study" or "evaluation" in the "calculation" may be appropriate. However, TES believes that completion of this effort by the applicant will have no impact on the conclusions of the IDR, and the changes are recommended only to provide an appropriate set of records that can be utilized for maintenance, replacement, repair, and modification.

17.7.4 Staff Conclusions

The staff reviewed the 16 findings identified in the IDR to determine the generic conclusion. The staff found that the IDR report was well organized and technically extensive, and provided an indepth review of the design process, analysis methods, and construction activities. The staff finds that the conclusions reached by TES were reasonably justified and that the generic aspects were resolved in an appropriate manner. On this basis, the staff concludes that the IDR provides further assurance that the piping systems in the Shoreham facility have been adequately designed to satisfy the applicable codes, standards, and staff requirements.

Furthermore, the staff believes that the recommendation by TES, as stated above, should be implemented by the applicant. In accordance with the proper QA procedures the applicant should formally document the studies and evaluations performed by the applicant as a result of this IDR to bring the existing calculations in line with the conclusions of the IDR. The staff will condition the Shoreham license to require that this documentation be completed before the plant exceeds 5% power.

22 TMI-2 REQUIREMENTS

I.A.2.3 Administration of Training Programs for Licensed Operators

Discussion and Conclusions

As part of IE Inspection Report No. 50-322/84-10, the staff inspector verified the implementation of this item. Shoreham instructors who teach systems, integrated response, transient, and simulator courses demonstrate SRO qualifications and are enrolled in appropriate requalification programs. This item is closed.

I.D.I Control Room Design Review

Discussion

Human factors engineering in nuclear power plants is addressed in SRP Chapter 18. The preliminary control room design review at Shoreham was consistent with SRP 18.4 and 18.5. The SRP 18.5 review was limited to the remote shutdown panel. The following is a summary of the results of the preliminary control room design review performed since publication of SSER 3.

SSER 3 lists 22 unresolved items for which improvements were to be implemented by the applicant and audited by the staff before fuel load. Implementation is complete on all items, and the improvements have been audited by the staff.

Conclusion

All implemented improvements are satisfactory to the staff. The staff concludes that, with these improvements, the potential for operator error leading to serious consequences as a result of human factors considerations in the control room will be sufficiently low to permit safe operation of the Shoreham facility.

This completes the pre-licensing staff evaluation of the Shoreham control room and the preliminary design assessment (PDA) portion of TMI Action Plan Item I.D.1. The plant must still be subjected to a detailed control room design review (DCRDR). Requirements for the DCRDR are identified in Supplement 1 to NUREG-0737. The DCRDR for Shoreham must also address all PDA issues that the staff agreed could be postponed until that review.

SSER 1 stated that the DCRDR would be completed within 1 year of the issuance of NUREG-0700. Since then, Supplement 1 to NUREG-0737 has been issued, so the schedule for the completion of the DCRDR will be determined in accordance with the supplement and will be made a condition of the Shoreham license.

I.G.1 Special Low Power Testing and Training

Position

TMI Action Plan item I.G.1, requires applicants for low power operating licenses to

> Define and commit to a special low power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training (NUREG-0694).

Before a full power license is issued, low power licensees are to

> Supplement operator training by completing the special low power test program. Tests may be observed by other shifts or repeated on other shifts to provide training to the operators.

Discussion and Conclusions

Beginning with the licensing of Sequoyah 1 in 1980, applicants for licenses for pressurized water reactors (PWRs) have complied with the I.G.1 requirements by conducting special testing and training in natural circulation and simulated degraded ac power conditions. The staff has not required these tests for follow-on units if the tests had been performed on the first unit and all licensed operators participated (e.g., Sequoyah 1 and McGuire 1 conducted a I.G.1 program, but Sequoyah 2 and McGuire 2 did not).

A meaningful I.G.1 program for BWRs comparable to the PWR program has not been defined. The BWR owners group's initial response to TMI Item I.G.1 was that it should not apply to BWRs because there are no additional tests analoguous to the PWR tests that would provide meaningful technical information and supplemental operator training. In a letter from D. B. Waters (BWR owners group) to D. G. Eisenhut (NRC), dated February 4, 1981, the owners group proposed that BWR applicants meet the I.G.1 requirement by augmenting reactor operator participation in the initial test program and by some additional preoperational tests.

After a review of this response, it was the staff's position that, to ensure compliance with I.G.1, BWR applicants should be required to perform some additional startup testing beyond that called for by RG 1.68 (and in addition to some tests proposed by the BWR owners group). The staff subsequently asked BWR applicants to commit to the recommendations of the owners group and to perform a simulated loss of all ac power (station blackout, SBO) test. The objective of the SBO test was to determine the temperature, pressure, and level responses and associated time constants of the reactor, drywell, containment, and vital spaces in the event of a loss of heating, ventilation, and air conditioning (HVAC) and cooling water, with decay heat being rejected to the suppression pool via the safety-relief valves. Decay heat was to be simulated by nuclear heat produced at low power, or the test could be postponed until later in the fuel cycle when sufficient decay heat was available.

The staff has received commitments from each new OL holder to conduct the test during the first fuel cycle when decay heat is available. However, the Susquehanna licensee, Pennsylvania Power & Light (PP&L), has indicated that a simulated loss of all ac power test would subject the drywell to a severe temperature and humidity transient with the potential of damaging equipment in the drywell. Several other BWR licensees have indicated that they would terminate the test before certain temperature limits in the drywell are exceeded. After further review of the basis for the requirement, the practicalities and value of such a test, and the proposed augmented owners group program, the staff concludes that the SBO test does not provide significant new information to justify its performance. Furthermore, because one of the original criteria for I.G.1 special tests (as stated in the Sequoyah SER) is that the test must not post a hazard to plant equipment, the staff has determined that the SBO test be deleted from the BWR I.G.1 staff position.

The staff finds that if it can be demonstrated that temperature and/or other SBO test conditions would adversely impact and pose a hazard to plant equipment, the BWR owners group recommendations by themselves would constitute compliance with Item I.G.1, because performance of the SBO test under less adverse conditions would not provide significant benefit for either training or design feedback. The staff also has not identified other special tests that should be performed on BWRs at this time. Therefore, the staff concludes that, unless a need is identified in the resolution of Generic Issue A-44, "Station Blackout," the SBO test should not be required for BWRs.

By letter dated February 16, 1984 (SNRC-1014), the applicant demonstrated the adverse impact the SBO test will have on plant equipment. The letter included evidence that loss of drywell cooling would pose a risk of damage to plant equipment in the drywell area and confirmed that the BWR owners group recommendations will constitute compliance with Item I.G.1. The staff has reviewed that submittal and concludes, for the reasons stated above, that the Shoreham license need not be conditioned to require such a test.

II.D.1 Performance Testing of BWR and PWR Relief and Safety Valves

Position

Light water reactor experience has included a number of instances of improper performance of relief and safety valves installed in the primary coolant systems. There have been instances of valves opening below set pressure, valves opening above set pressure, and valves failing to open or reseat. It is not known if these instances occurred because of the limited qualification of the valve or because of the basic unreliability of the valve design. However, while it is known that the failure of a power-operated relief valve to reseat was a significant contributor to the TMI-2 sequence of events, such an event in a BWR would not have the same severe consequences. Nevertheless, these facts led the task force that prepared NUREG-0578 to recommend that programs be developed and executed that would reexamine the performance capabilities of BWR relief and safety valves for unusual but credible events. These programs were deemed necessary to reconfirm that GDC 14, 15, and 30 are satisfied.

GDC 14, 15, and 30 require (1) that the reactor primary coolant pressure boundary be designed, fabricated, and tested to have an extremely low probability of abnormal leakage; (2) that the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to ensure that the design conditions are not exceeded during normal operation or anticipated transient events; and (3) that the components that are part of the reactor coolant pressure boundary shall be constructed to the highest quality standards practical.

To reconfirm the integrity of relief and safety valve systems and thereby ensure that the GDC are met, in a letter dated September 13, 1979, the staff made the NUREG-0578 position a requirement for all operating nuclear power plants. This requirement was subsequently incorporated as Item II.D.1 of NUREG-0737.

Clarification

As stated in the NUREG-0578 and NUREG-0737, each BWR licensee and applicant shall

(1) Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

(2) Determine expected valve operating conditions through analyses of accidents and anticipated operational occurrences referenced in RG 1.70, Revision 2.

(3) Choose the single failures for these valves so that the dynamic forces on the relief and safety valves are maximized.

(4) Use the highest test pressures predicted by conventional safety analysis procedures.

(5) Include in the relief and safety valve qualification program the qualification of the associated control circuitry, piping, and supports.

(6) Test data--including criteria for success or failure of valves tested--must be provided for staff review and evaluation. These test data should include data that would permit plant-specific evaluation of discharge piping and supports that are not directly tested.

(7) Each licensee and applicant must submit a correlation or other evidence to substantiate that the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show that the test conditions used are equivalent to expected operating and accident conditions as prescribed in the FSAR. The effect of as-built relief and safety valve discharge piping on valve operability must be accounted for if it is different from the generic test loop piping.

Discussion

To respond to the requirements listed above, the BWR owners group contracted GE to design and conduct an SRV test program. The program describes the relief and safety valves to be tested, the test facility requirements, the test sequence, the valve acceptance criteria, and the procedure for obtaining, analyzing, and reporting the test data. Before the test program was accepted, it underwent extensive staff review and comment, followed by responses from the GE BWR owners group.* On the basis of this review, the staff considers the concerns expressed in the questions appropriately resolved.

The test sequence and conditions established in the test program were based on an evaluation of expected operating conditions determined through the analyses of accident and anticipated operational occurrences referenced in RG 1.70, Revision 2. Enclosure 2 to D. B. Waters' September 17, 1980 letter provides this evaluation, which indicated that there is one event that is significantly likely to occur and can lead to the discharge of liquid or two-phase flow from the SRVs. This event, considered with the single failure requirement of NUREG-0737, results in the conclusion that a test should be performed simulating the alternate shutdown cooling mode that utilizes the SRVs as a return flow path for low pressure liquid to the suppression pool.

At a meeting on March 10, 1981,** the BWR owners group presented results of a study by Science Applications, Inc. (SAI) that showed that the probability of getting liquid to the steamline--and hence to the SRVs--is approximately 10-2 per reactor year. However, even if the water level increases to the mid-plane of the steamline nozzle on the vessel, which is not likely,*** the fluid quality at the valve was calculated by GE to be greater than 20%. Because the steamlines

*See letters from D. B. Waters (BWR owners group) to R. H. Vollmer (NRC) dated September 17, 1980 ("NUREG-0758 Requirement 2.1.2, Performance Testing of BWR and PWR Relief and Safety Valves") and to D. G. Eisenhut (NRC) dated March 31, 1981 ("Response to NRC Questions on BWR S/RV Test Program"), and from B. F. Saffell to R. E. Tiller, dated April 23, 1981 ("Comments on BWR Owners Group Responses to NRC Questions on Safety/Relief Valves Low Pressure Program").

**Wayne Hodges (NRC), memorandum to T. P. Speis, "Summary of March 10 Meeting with GE to Discuss BWR Liquid Overfill Events," May 8, 1981.

***Feedwater pumps would be tripped before the water level reaches the mid-plane by the L8 high level trip, turbine vibration trip, or operator action.

typically drop about 45 feet vertically from the vessel nozzles to the horizontal runs on which the SRVs are mounted, much of the liquid that gets to the steamlines would be entrained as droplets. Therefore, should liquid reach the level of the steamlines, the two-phase mixture upstream of the SRVs would exist as a froth, droplet, annular, or stratified flow regime, and slug flow or subcooled liquid flow would be unlikely.

Even if two-phase discharge through a SRV should result in a stuck-open valve, the results of the blowdown are not severe. As discussed in NUREG-0462, there were 53 inadvertent blowdown events as a result of pressure relief system valve malfunctions from 1969 through April 1978. These events varied in consequences from a short-duration pressure transient to a rapid depressurization and cooldown of the primary coolant system from approximately 1100 psig to a few hundred psig. No fuel failures as a result of these transients were reported.

A letter from D. B. Waters to D. G. Eisenhut (NRC) dated December 29, 1980 (BWROG-80-12), the BWR owners group discussed the consequences of the worst case transient for maintaining the core covered (loss of feedwater) combined with the worst single failure (failure of the high pressure injection system) and one stuck-open relief valve. Reference plant analyses for a BWR 4 and a BWR 5 show that the reactor core isolation cooling system can automatically provide enough inventory to keep the core covered. This capability is not a design basis for the RCIC system, and not all plants have been analyzed to demonstrate this capabilty. If a plant does not have this capability, manual depressurization of low pressure core cooling systems will avoid core uncovery for the case of loss of feedwater plus worst single failure plus a stuck-open relief valve. Therefore, even for the loss of feedwater transient with the worst single failure, a stuck-open relief valve does not uncover fuel.

At the March 10, 1981 meeting, the BWR owners group presented an analysis that showed that even if a slug of subcooled water exists upstream of the SRVs, the probability of rupturing the discharge line is 7×10^{-4} per event. The staff has not reviewed the supporting analysis for this value; however, even if the failure probability is as high as 10^{-2} per event, the combined probability is no greater than for a steamline break inside containment. GE states that the steamline break, which has been analyzed and found to be acceptable, would be more severe (effects on the core and containment) than a break in an SRV discharge line with a stuck-open SRV because the assumed break area is larger.

In summary, based on the history of inadvertent SRV blowdowns in operating BWRs, the low likelihood of severe consequences, and the bounding design-basis steamline break, the staff decided not to require high pressure testing with saturated liquid or subcooled water.

On this basis, the applicant has complied with requirements 1 through 4 above. That is, an acceptable test program was established that adhered to the staff guidelines on the selection of test conditions and the maximization of system loads. That portion of requirement 5 dealing with the qualification of the associated control circuitry is considered to be satisfied as a result of the anticipated licensing action for compliance with 10 CFR 50.49.

In October 1981, the BWR owners group published a technical report* documenting the results of the prototypical SRV tests conducted in accordance with the accepted test program. The tests were performed by GE for the BWR owners group at the Wyle Laboratory in Huntsville, Alabama. The test report, which was reviewed by the staff, describes the test facility, the basis for the test conditions and valve selection, and the instrumentation and its accuracy, and analyzes the results with respect to valve operability, piping and supporting loads, and the applicability of the results to the inplant SRVs.

With the completion of the testing and the submittal of the test report, the applicant complied with requirement 6 above. However, the subsequent staff review of the test results generated six plant-specific questions. The applicant's response to these was submitted for review December 15, 1982 (J. L. Smith (LILCO), letter to H. R. Denton (NRC), SNRC-812).

NRC staff consultants (EG&G Idaho, Inc.) conduct an extensive review of the test results.** The review addressed not only the test results, but also the applicability of the test results and equipment to the Shoreham SRV systems. The six plant-specific questions generated by the review and the applicant's responses to those questions are discussed below.

The generic test program required the testing of six different SRVs. Included was a Target Rock 6 x 10 two-stage pilot-operated safety/ relief valve, Model 7567F. This valve, with minor differences, is the valve used in the Shoreham plant. The tested valve was different from the plant valves in the following areas:

(1) topwork, design
(2) seat bore diameter
(3) main disk lift position

The only differences in the top works are dimensional, which would not affect the operability of the valve or the piping reaction loads from water discharge. Exact dimensions for the Shoreham valves were not provided in the test report; however, the owners group inplant valves have seat bore diameters and disk lift values that range from 4.27 inches and 2.58 inches, respectively, to a 5.25-inch diameter seat bore and a 2.63-inch lift, thereby bounding the maximum flow capacity.

Although the Shoreham plant does not employ the three-state Target Rock valve, it was included in the test program. The three-stage test valve has a bore diameter of 4.27 inches and was considered bounding from an operational standpoint, because flashing under the water test conditions would be more likely to occur with the smallest bore diameter.

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*GE Topical Report NEDE-24988-P, "Analysis of Generic BWR Safety Relief Valve Operability Test Results," October 1981.

**Letters from B. F. Saffell, EG&G Inc., to R. E. Tiller, DOE, Idaho Operations Office, dated January 13, 1982 ("Review of BWR GE Safety Relief Valve Test Report") and to D. E. Solecki, DOE Idaho Operations Office, dated May 4, 1982 ("Open Questions-BWR GE Safety/Relief Valve Test Report").

Thus, the two-stage test valve bound the maximum flow capacity and discharge line loads that could be expected for the inplant valves, and the three-stage test valve verified the operability of the Shoreham inplant valves.

As discussed above, test conditions to envelop the expected BWR SRV events were developed in accordance with NRC guidelines and were accepted. The review of the test results indicates that the actual test conditions were in accordance with the established test program.

Applicant's Responses to Plant-Specific Questions

(1) Question 1

The response to Question 1 indicates that there are SRV discharge line differences between the test configuration and the inplant configuration. However, the response notes that these differences result in bounding loads on the safety valves. The first segment of test piping downstream of the safety valve is longer than the comparable inplant segment, which would result in a larger moment at the test valve. Discharge from the tee quencher at the end of the Shoreham safety valve discharge line cannot transmit loads to the valve quencher and the valve. Thus, this portion of the response is considered acceptable.

The second part of the response addressed the back pressure (dynamic, hydraulic) loads on the test and inplant valves. The applicant addressed both transient and steady-state back-pressure loads. The steady-state back pressure for the test valve was forced to be greater than that expected in the plant by installing a predetermined orifice plate in the discharge line before the ram's head and above the water line The response also indicated that the high pressure steam test preceeding the low pressure water test would produce the greater transient back pressures. This would be true because of the higher pressure upstream of the safety valve and the shorter valve opening time. Additionally, the test facility discharge line submergence is greater and the total line length is shorter than the Shoreham discharge line, so the test facility had a smaller air volume and hence a larger back pressure.

On the basis of the above discussion, the staff considers the response to the first question acceptable.

(2) Question 2

In the plant-specific response to Item II.D.1, the applicant referenced GE Topical Report NEDE-24988-P as the basis for concluding that the Shoreham SRV discharge piping and supports were designed with sufficient conservatism to withstand the fluid transient and deadweight loads resulting from the operation of the alternate shutdown cooling mode.

NEDE-24988-P contains a description of the generic test facility that was designed to be prototypical of BWR plants in terms of discharge piping configuration. The generic test program determined that the fluid transient line forces resulting from the alternate shutdown cooling mode liquid discharge are of substantially lower magnitude than those resulting from the design-basis high pressure steam discharge events. Because the test facility piping was supported by rigid supports and snubbers, it could be concluded that rigid pipe supports and snubbers that are adequate for the steam discharge loads are also acceptable for loads associated with the alternate shutdown cooling liquid discharge.

In its review of the GE Topical Report, the staff agreed with the conclusion for plant-specific discharge piping systems supported similarly to the test facility piping (i.e., supported solely by rigid supports and snubbers). However, most inplant SRV discharge piping systems are also supported by one or more unpinned spring hangers. Excessive deflection of unpinned spring hangers from large liquid deadweight loads associated with the alternate shutdown cooling mode could result in large stresses on piping and supports and increased SRV loads. This concern was Question 2 in the staff's request for additional information.

The staff requested that the applicant (1) provide plant-specific information regarding the Shoreham SRV discharge piping and supports, (2) compare anticipated SRV loads for the Shoreham supports with those measured in the generic test program, and (3) describe the impact of any differences on SRV operability.

The applicant provided a written response to the staff's concern in prepared testimony transmitted to the Shoreham Atomic Safety and Licensing Board (ASLB) July 29, 1982.

In this response, the applicant described the Shoreham plant-specific SRV discharge piping and the types of supports used, including the one or two spring hangers used on each discharge line, all of which are located in the drywell. The applicant further stated that analysis of a typical Shoreham SRV discharge line had confirmed the applicability of the Topical Report generic results for rigid pipe support and snubbers (i.e., loads resulting from low pressure liquid flow during the alternate shutdown cooling mode of operation are of substantially lower magnitude than those resulting from design-basis high pressure events). Therefore, the design adequacy of the Shoreham plant-specific snubbers and rigid supports is ensured because they are designed for the larger steam discharge loads.

Regarding the one or two spring hangers installed on each SRV discharge line, the applicant stated that sufficient margin existed in the Shoreham design to adequately offset the increased dead weight load on the hangers in the unpinned condition. Nevertheless, the applicant committed to perform stress analyses to confirm that adequate margins exists for all SRV discharge piping and supports, specifically taking into account increased deadweight loads on the unpinned hangers.

In a letter dated December 15, 1982 from J. L. Smith (LILCO) to H. R. Denton (NRC), the applicant transmitted a description of the results of the confirmatory stress analyses. Each SRV discharge line in the drywell has been analyzed to determine pipe stresses and support loads that result from the deadweight of the water in the pipes, concurrent thermal effects, and the effects of an assumed concurrent safe-shutdown earthquake.

In verbal testimony at the ASLB hearing on July 29, 1982, the applicant committed that pipe and support stresses would comply with ASME Code faulted condition stress limits for the referenced combination of loads. At the hearing, the staff accepted the faulted stress criterion. The staff also noted that the applicant's methods of piping analysis, related computer codes, etc. had been reviewed and accepted by the staff, and this acceptance was documented in the Safety Evaluation Report. The staff also notes that the faulted stress limit does permit stresses to exceed the yield strength. Some inelastic deformation and consequent loss of piping cross-sectional flow area could result in piping with stresses at the faulted limit. However, because the faulted limit ensures that structural integrity is maintained, and because there are 11 SRV discharge lines that can be utilized for flow, there is adequate assurance of sufficient flow area so that the required shutdown cooling water flow can be maintained.

In the December 15, 1982 letter, the applicant confirmed that the results of the SRV wetwell discharge pipe analyses verified that, for the above combination of loads, piping stresses were well within the faulted condition values allowed by the ASME Code. Also, each pipe support was within its applicable allowable design value for the same combination of loads. The applicant further noted that the spring hangers of concern had been designed to carry the full weight of water associated with the hydrotest condition, although during hydrotesting the hangers are pinned to minimize deflection. The applicant reported that for the case of the alternate shutdown cooling mode, where the hangers are not pinned, the hanger travel distances are within the working range of the springs, thus ensuring that they will not bottom-out during this mode of operation.

To provide additional assurance that operation in the alternate shutdown cooling mode will not impose loads on the SRVs beyond their design-allowable values, the applicant has noted that none of the Shoreham SRV discharge lines have any spring hangers in the wetwell. Because the lines are anchored at the drywell floor, loads imposed in the wetwell area are not transmited to the SRVs.

A confirmatory stress analysis was done on the wetwell discharge line judged by the applicant to be most likely to be heavily loaded during alternate shutdown cooling. All pipe stresses and support loads were within design-allowable values. Although the applicant had concluded, from this one analysis, that there is no remaining concern regarding wetwell piping, the applicant had committed to perform confirmatory stress analyses of the balance of the wetwell piping before fuel load.

In a letter dated April 6, 1983, from J. L. Smith (LILCO) to Harold R. Denton (NRC), the applicant reported that the stress analyses for the balance of the wetwell piping had been completed and that all pipe stresses and support loads were well within design allowables. Thus, the staff concludes that the applicant has provided sufficient assurance of SRV discharge piping integrity for the alternate shutdown cooling mode of operation and that the related piping loads imposed on the SRVs will have no adverse affect on valve operability.

The staff thus considers the issues raised in Question 2 resolved.

(3) <u>Question 3</u>

Question 3 inferred that, during testing, there may have been valve functional deficiencies or anomalies encountered that invalidated test runs and were not reported in the test results because there were subsequent valid test runs.

The applicant's response to this question states, "All the valves subjected to test runs, valid or invalid, opened and closed without loss of pressure integrity or damage." This statement was supported by the submittal of the Wyle Laboratory test log sheet for the two-stage Target Rock valves. Thus, the staff finds the response to Question 3 acceptable.

(4) Question 4

Question 4 asked the applicant to describe and compare expected events at Shoreham with the conditions of the generic test program. The applicant summarized the analysis procedure using RG 1.70 and determined eight events that would result in liquid or two-phase flow through the safety valves and maximize the dynamic forces on the valve. As indicated above, this analysis concluded that the alternate shutdown cooling mode is the only expected event that will result in liquid at the valve inlet. To simulate this event, the applicant's test program used a 15°F to 50°F subcooled liquid at 20 to 250 psig at the safety valve inlet before valve opening. The applicant indicates that the alternate cooling mode of operation at Shoreham will result in subcooled fluid at a pressure less than 250 psig. Therefore, the test conditions envelope the expected conditions for this event, should it occur in the Shoreham unit. The applicant's response to Question 4 is acceptable to the staff.

(5) Question 5

Question 5 addressed the effect on valve performance of steam flow cycling of the valves before the low pressure liquid flow event. The sequence to arrive at the alternate shutdown cooling mode is described in the response, which indicates that the SRV would be cycled under steam conditions to maintain a 100°F cooldown rate. The test program and the actual tests included only one steam cycle, the purpose of which was to bring the valve up to the proper service temperature before the low pressure liquid test. Thus, any adverse effect of several high pressure steam cycles on valve performance during the liquid test was not included. The response indicates that the valve vendors subject their valves to steam flow cycling and that no loss of valve performance has been noted. The response to this question is acceptable to the staff. (See below for further discussion on the effect of steam flow cycling.)

(6) Question 6

The response to Question 6 addressed the determination and future use of the valve flow coefficient, C. The response indicates that the value of the liquid flow coefficient in itself is not of direct interest. The flow capacity of the valves as measured during the tests is the value of interest. The flow capacity of the system safety valves is larger than the capacity of the coolant source pump of the RHR system and, therefore, is sufficient to remove decay heat. The answer to this question is considered acceptable to the staff.

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*Letters from D. B. Waters (BWR owners group) to R. H. Vollmer (NRC), dated September 17, 1980, and from J. L. Smith (LILCO) to H. R. Denton (NRC) dated December 15, 1982.

Summary

On the basis of the above evaluations, the staff finds that the applicant has provided an acceptable response to items 5 and 7.

The two-stage Target Rock valve has been in service on operating BWRs for only a short period of time (several years). Set pressure inservice test data compiled to date for this valve indicate that, after initial or subsequent setpoint adjustment, the valve setpoint tends to drift in an upward direction after some period of operation in a BWR plant.

Technical Specifications for BWR plants require that SRVs be adjusted to open within +1% of their required set pressure. As found in prior adjustments, two-stage valve data indicate that most valves have been opening in a range of 1% to 4% above nominal set pressure, with a few valves opening at a considerably higher value.

Additionally, during a plant transient at one BWR in mid-1982, all two-stage valves exhibited setpoint drift greater than 4%, but, on subsequent inservice bench testing, they opened in the more typical range of 1% to 4%.

In response to the NRC and industry concern about the high setpoint drift exhibited by the two-stage valves, a BWR owners group SRV drift committee has been formed; the committee consists of at least some of the utilities that use or plan to use the two-stage valve. The owners group is funding GE research to determine the exact nature of the setpoint drift phenomenon.

Resolution of the two-stage Target Rock valve high setpoint drift issue will be addressed by the staff as a separate action when the owners group program is complete.

The staff (above) has accepted the response regarding the SRV discharge piping system to the response of the inplant piping system.

The applicant's test report indicated (1) that the analytically predicted response of the test piping and supports was comparable to the measured values, and (2) that the maximum test piping response to liquid flow was generally less than 30% of that due to test steam flow conditions. Further, as part of the initial review, the loads on the inplant piping and supports as a result of steam discharge were found to be acceptable by the staff.

Conclusions

The applicant has provided an acceptable response to the requirements of NUREG-0737 Item II.D.1 and, thereby, reconfirmed that GDC 14, 15, and 30 have been met.

With concurrence by the staff, the applicant developed an acceptable relief and safety valve test program designed to qualify the operability of the prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The subsequent tests were successfully completed under operating conditions that, by analysis, bounded the most probable maximum forces expected from anticipated design-basis events.

The generic test results showed that the valves tested functioned correctly and safely for all steam and water discharge events specified in the test program and that the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the applicant's justifications indicated the direct applicability of prototypical valve and valve system performances to the inplant valves and systems intended to be covered by the generic test program.

Thus, the requirements of Item II.D.1 of NUREG 0737 have been met, ensuring that the reactor primary coolant pressure boundary will have, by testing, a low probability of abnormal leakage (GDC 14) and that the reactor primary coolant pressure boundary and its associated components (piping, valves, and supports) have been designed with sufficient margin so that design conditions are not exceeded during SRV events (GDC 15). Further, the prototypical tests and the successful performance of the valves and associated components have demonstrated that this equipment has been constructed in accordance with high quality standards (GDC 30).

II.E.4.2 Containment Isolation Dependability

Discussion and Conclusion

SSER 3 specified a license condition that would require the applicant to provide a high radiation isolation signal to the purge/vent isolation valves. (A conceptual design for this modification was provided in a letter dated August 31, 1982 (SNRC-762).) In a letter dated May 1, 1984 (SNRC-1038), the applicant advised the staff that these plant modifications have been physically completed and satisfactorily tested. This item is resolved.

II.F.2 Instrumentation for Detection of Inadequate Core Cooling

Discussion

The applicant has performed a plant-specific study, "Review of the Shoreham Water Level Measurement System" (SLI-8221, September 1982). This study describes the current Shoreham reactor water level measurement system (RWLMS) and its compliance with the RWLMS improvements recommended in SLI-8211. The staff reviewed this study and found it acceptable, except that, with the RWLMS originally proposed for Shoreham, early operator action would be required in the event of an instrument line failure (leak or break) accompanied by a single additional component failure.

As a result of an agreement reached during the Shoreham ASLB hearings, the applicant agreed to modify portions of the RWLMS and ECCS initiation logic. This agreement resulted in the following Shoreham license condition:

> By July 1, 1983, LILCO shall submit to the staff a description and schedule for hardware modifications to the Shoreham reactor vessel water level measurement system to eliminate dependence on early operator action during events involving an instrument line failure (leak or break) and a single additional component failure, in accordance with the second recommendation in the BWR Owners Group Report SLI-8211 (July 1982). The proposed modifications and schedule must be acceptable to the staff and installation must be completed no later than the end of the second refueling outage. (Agreement at 7-8, II.B.1). (NOTE: The proposed modifications will be installed as soon as practicable, but in no event later than the end of the second refueling outage.) (Agreement at 8, II.B.3).
>
> LILCO shall implement any staff requirements regarding additional instrumentation for detection of inadequate core cooling which may result from the staff's review of the BWR Owners' Group Report on this subject in conjunction with LILCO documentation addressing the subject. (Agreement at 16-17, III.B.3).

The applicant subsequently proposed a modification to the RWLMS (in a letter, from J. L. Smith to H. R. Denton (NRC), dated July 19, 1983) to resolve the staff concerns in this area, and the applicant has proposed to implement these modifications before the end of the second refueling outage.

The physical modification entails the installation of four new transmitters on existing racks or on adjacent new racks. Instrument piping must be tapped and run to the transmitters, and new cables will have to run from the racks in the secondary containment to the analog transmitter trip system panels in the relay room of the control building. The existing relay logic for HPCI and RCIC will have to be modified so that it correlates to the new transmitter assignments, and the applicant will perform a safety evaluation in accordance with 10 CFR 50.59.

The relay logic modification consists of adding four level sensors, reassigning initiation and trip signals to the HPCI and RCIC control logic, and modifying power distribution to ensure that all HPCI control is associated with bus B and all RCIC control is associated with bus A. The turbine controls of the

HPCI and the RCIC are powered by buses B and A, respectively. This modification reassigns the level initiation and trip logic to the same buses as the turbine control of each.

Conclusion

The staff has completed its review of the applicant's responses concerning this issue and has found that the Shoreham RWLMS fully conforms with the water level instrumentation modifications recommended in SLI-8211; no further modifications are required. The staff has also completed its review of SLI-8218 and has accepted the recommendation that, if the reactor water level instrumentation is fully upgraded according to SLI-8211 recommendations, no additional instrumentation is required for the detection of inadequate core cooling. Because the Shoreham RWLMS fully conforms with the recommendations of SLI-8211, no additional instrumentation for detection of inadequate core cooling is required.

II.K.1.5 Assurance of Proper Engineered Safety Features Functioning

Discussion and Conclusions

As part of IE Inspection Report No. 50-322/84-10, an NRC staff inspector reviewed valve positioning and verified the maintenance of proper valve position. The plant is designed to annunciate certain offnormal valve position conditions in accordance with FSAR Chapter 7 and RG 1.47. The applicant conducted a systematic review of engineered safeguards systems to ensure that disabling valve conditions (except for manual valves) result in control room annunciation.

During a review of engineered safeguards systems, two instances were identified where an unannunciated inoperable system lineup could occur. These conditions were closure of a single RHR pump suction valve and the blocking shut of LPCI valves by the shutdown cooling isolation signal. These conditions apparently did not satisfy the applicant's original commitment to RG 1.47 and IEB 79-08. The applicant has modified tne system level annunciation for RHR to alarm when a single RHR pump suction valve is closed.

The inspector reviewed plant modification package DOP 83-121, which was completed in April 1984. This modification was properly approved and installed. Circuit testing was conducted on April 12, 1984, in accordance with Procedure 87.001.06 (Checkout of Low Voltage Control Circuits, Revision 0). The inspector reviewed the test documents and verified satisfactory completion of the test.

The applicant determined that the control room indication of shutdown cooling isolation initiation was sufficient annunciation of the inoperable condition of the LPCI injection valves in this situation. This position was formalized in FSAR Revision 32. The inspector reviewed Procedures 23-121.01 (Residual Heat Removal System, Revision 7) and 23-204.1 (Low Pressure Coolant Injection, Revision 2 to verify that the operators are directed to reset shutdown cooling isolation on receipt of a safety injection signal. This item is closed.

The applicant also conducted a review of plant procedures to ensure that manual valves manipulated by these procedures are repositioned and verified upon completion of the evolution. In addition, the applicant has monthly manual valve position verification surveillance procedures for all engineered safety feature systems. The inspector reviewed these administrative controls and determined that they provide reasonable assurance of proper system alignment. This item is closed.

II.K.1.10 Safety-Related System Operability Status Assurance

Discussion and Conclusions

As part of Inspection Report No. 50-322/84-10, an NRC staff inspector reviewed the applicant's control of the removal of safety-related system from service. The applicant conducted a review of maintenance and surveillance procedures to identify those procedures that remove safety systems from service. In addition, the applicant's Procedures 12-013-01 (Maintenance Work Requests, Revision 16) and 12-016-01 (Surveillance Program, Revision 7) provide for shift engineer approval of the removal of equipment from service and its return to service.

The inspector reviewed these procedures and found that adequate controls of safety-related equipment existed, except that Procedure 12-016-01 did not delineate the responsibilities of the shift engineer before the equipment is removed from service. The applicant issued Procedure Change Notice 84-586 to revise the procedure to conform with the guidance of American National Standards Institute (ANSI) Standard N18.7(1976) paragraph 5.2.6. Ths issue is resolved.

II.K.3.13 Separation of HPCI and RCIC System Initiation Levels

Position

This item required re-analysis of the RCIC system actuation level setpoint. The objective was to cause RCIC initiation before HPCI injection during a reactor vessel level transient, possibly eliminating the HPCI injection and reducing reactor vessel thermal fatigue.

Discussion and Conclusions

The applicant's stated position on NUREG-0737 Item II.K.3.13, as discussed in SSER 1, conforms with that taken by the BWR owners group; that is, there is no significant advantage to changing the RCIC or HPCI actuation level setpoint.

On a second issue, the applicant committed to and modified the high reactor vessel water level isolation of the RCIC steam turbine. Tripping the turbine steam admission valve has been replaced by applying a closure signal to the turbine supply valve, 1E51*MOV043. This motor-operated valve will re-open to initiate RCIC flow if reactor water level drops to the low level setpoint. The plant design change was implemented through GE Engineering Change Notice NJ28490 and Field Disposition Instruction TFEN.

As discussed in IE Inspection Report 50-322/83-38, dated February 3, 1984, an NRC regional inspector verified that Procedure SP23.119.01, Revision 5, dated December 13, 1983, correctly addresses system response to a high reactor vessel level isolation. Procedures SP44.119.07 (RCIC Automatic Isolation Logic System Functional Test, Revision 4, dated November 4, 1983, Sections 8.31 through 8.38) and SP44.119.11 (RCIC Initiation Logic System Functional Test, Revision 5, dated January 10, 1984, Section 8.9.11) have been revised to test the modified logic systems. This item is resolved.

II.K.3.18 Modification of Automatic Depressurization System Logic

Discussion and Conclusions

By letter dated August 5, 1983 (SNRC-947), an applicant adopted the results of the BWR owners group report on II.K.3.18, "Modification of Automatic Depressurization System (ADS) Logic: Feasibility for Increased Diversity for Some Events." The applicant has committed to modify the ADS logic by deleting high drywell pressure permissive and adding a manual switch that may be used to inhibit ADS actuation if necessary. This is consistent with Option 2 of the owners group study and is acceptable to staff, as discussed in the staff memorandum from R. W. Houston to G. C. Lainas, "Evaluation of BWR Owners Group Generic Response to Item II.K.3.28," dated April 1, 1983.

In a filing before the Shoreham ASLB dated January 16, 1984, the applicant reported that implementation of the ADS logic modifications was expected to be complete by February 1984, and in a letter dated May 1, 1984 (SNRC-1038), the applicant advised the NRC staff that the plant modifications have been physically completed and satisfactorily tested. An NRC regional inspector will verify that instruction regarding the use of the inhibit switch has been addressed in the plant emergency procedures. Additionally, use of the manual inhibit switch will be included in the plant Technical Specifications.

The staff has determined that the conceptual design for ADS logic modifications proposed by the applicant is acceptable for resolution of Item II.K.3.18. With the installation of the required modifications, this item is resolved.

III.D.3.4 Control Room Habitability

Discussion

This item addresses the need for the applicant to ensure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can be safely operated or shut down under design-basis accident conditions. The applicant submitted the results of its evaluations to the staff, which reviewed the submittal and published the results in SSER 1. In SSER 1, the staff accepted the applicant's systems and analyses and stated (1) that the applicant had further committed to include provisions for carbon dioxide (CO_2) detection and alarm and (2) that when these additional modifications had been completed, the applicant will have satisfied the requirements for control room habitability.

Conclusions

As reported in IE Inspection Report 50-322/83-08, dated April 12, 1983, an NRC regional inspector reviewed the documentation associated with the installation of the CO_2 monitors including the FSAR, SER, and engineering and design coordination report (E&DCR) P-3834. The inspector toured the plant and verified that the detectors had been installed in accordance with the E&DCR. The inspector also reviewed the results of the checkout and initial operation procedure and noted that the CO_2 monitors had been checked and calibrated successfully. The inspector also reviewed the preoperational test procedure for the control room air conditioning (CRAC) system and noted that steps had been included in this procedure to verify that the CO_2 monitors would, on detection of high CO_2 levels, isolate the air intake valves, initiate an alarm, and print a warning on the process computer alarm printer. The inspector identified no discrepancies. This TMI action item is resolved.

APPENDIX A

PRA REVIEW OF SHOREHAM INTERNAL FLOODING

CONTENTS

1 INTRODUCTION

This appendix documents the work performed as part of the NRC technical assistance program at Brookhaven National Laboratory (BNL) to support the NRC staff in reviewing the Shoreham PRA flooding analysis. This appendix provides the staff's assessment of the Shoreham review, along with the BNL report.

1.1 Background

A memorandum[1] dated November 16, 1982 on the staff's preliminary review of internal flooding at the Shoreham reactor building was transmitted from Stephen Hanauer to Darrell Eisenhut. The preliminary review was performed on a draft report submitted by Future Resources Associates, Inc. (FRA),[2] the consultants for Suffolk County, and on the draft Shoreham probabilistic risk assessment (PRA) submitted by the applicant (LILCO). The concern raised by FRA was that the draft Shoreman PRA underestimated the frequency of certain internal flooding accident sequences by a factor of more than 1000.

On the basis of its preliminary review at that time, the NRC staff believed that flood accident sequences did not contribute significantly to risk. However, the staff recommended that LILCO verify the PRA analysis regarding the following items:

(1) the potential for flooding at elevation 8 of the reactor building

(2) the potential for flood-induced reactor scram

(3) the probabilities for each accident scenario based on maintenance schedules and procedures for emergency core cooling (ECC) and reactor core isolation cooling (RCIC) systems

On December 2, 1982, the applicant submitted an analysis performed by its contractor, Science Applications Inc. (SAI)[3], to respond to the FRA concern on Shoreham flooding. On June 24, 1983, the applicant submitted the final report on the Shoreham PRA,[4] which included the most up-to-date analysis on flooding.

With the help of BNL, the staff has reviewed the December 2, 1982 submittal and the final Shoreham PRA on the flooding issue.

Section 2 discusses some aspects of the data used in the analysis, in particular, the initiating event frequencies and operator error probabilities; this section includes a discussion of alarm-response procedures. Sections 3 and 4 discuss the methodology and uncertainty analysis. Section 5 gives the summary and conclusions.

2 DATA USED IN THE ANALYSIS

2.1 Evaluation of Flood-Initiator Event Frequencies

There are two types of initiator events that will lead to flooding of the reactor building at Shoreham. Flooding may be initiated either as a result of not isolating a system that is undergoing maintenance or as a result of a rupture in the system. What follows is a description of each type of initiator event.

2.1.1 Maintenance-Induced Flood

The applicant has obtained operating experience records based on licensee event reports (LERs)[5] for turbine-driven pumps and motor-driven pumps in ECC and RCIC systems. The LERs covered events up to 1978.

The staff has also obtained operating experience records for the pumps; however, the LERs examined by the staff[6] covered events up to 1980. Using the more up-to-date data base, the staff estimates higher failure rates for the pumps. These failure rates were used to determine the frequency of maintenance-induced flood events.

2.1.2 Pipe-Break-Induced Flood

To assess the rupture frequency quantitatively, the applicant considered ruptures of pipes, welds, valves, and pump casings.

The general approach used by the applicant to calculate the frequency of a flood-initiated by a rupture in an ECC or RCIC system is as follows:

(1) The applicant identified the appropriate type and length of piping and number of components in an ECC or RCIC system susceptible to rupture.

(2) The applicant used the LER information in NUREG/CR-1363[7] and the estimates for leakage and rupture rates in WASH-1400[8] to calculate the rupture rates for various ECC systems.

The staff review of BWR operating experience on flooding as a result of ruptures noted that, in April 1978 at Browns Ferry Unit 3, the supply line to the condensate ring header, which provides makeup to the high pressure coolant injection (HPCI) and RCIC systems, failed at a welded joint. The weld failure resulted in flooding of the core spray pump room. The applicant did not include this event in the data base.

The staff notes that the weld at Browns Ferry was mainly aluminum, whereas the welds in HPCI system at Shoreham are stainless steel. However, the staff has included the Browns Ferry event in estimating the frequency of floods initiated by ruptures.

2.2 Operator Error Probabilities

2.2.1 Types of Operator Errors

Operator errors play significant roles in initiation of a flood and in plant recovery during a flood. The different types of operator errors in a flooding scenario at Shoreham are described as follows:

(1) During a maintenance of a ECC or RCIC pump, an operator may disconnect the electric power to equipment and isolation valves by pulling and tagging the appropriate breakers at motor control centers. A second person must verify that tagging has been performed properly. If, as a result of operator error, the electric power to an isolation valve is not removed and a demand to open the valve occurs during maintenance, there would be an open path from the water sources to the reactor building.

The demand may be an actual demand for the system or may be a manual demand as a result of an operator inadvertently operating a switch in the control room.

(2) During maintenance of a pump, an operator may inadvertently, by manual local operation, open an isolation valve and cause a flood in the reactor building.

(3) When a flood in the reactor building is annunciated by alarms in the control room, an operator may fail to notice the light, which is on a back panel.

(4) When a flood occurs in the reactor building, an operator must promptly identify the source of flood and isolate it before it reaches the 3 foot-10 inch level, which disables all ECC and RCIC components,

The human error probabilities used by the applicant are based on NUREG/CR-1278[9].

2.2.2 Procedures Review

The staff has reviewed the procedures for operators for mitigating a flood and notes that there are specific procedures at Shoreham for detecting and isolating leakages from ECC and RCIC systems. However, the staff also notes that the Shoreham alarm-response procedures specify only general guidelines for monitoring system parameters to determine the leakage location and for initiating leak isolation. The procedures fail to include a list of specific requirements for operators to systematically check the operation parameters of ECC and RCIC systems. Because there are many system parameter indicators in the control room, operators may fail to discover the abnormal system parameters. A check-list with specific steps that should be followed during a flood in the reactor building would be helpful to operators to reduce confusion and to avoid undue delays in operator response.

Regarding maintenance procedures for pulling and tagging breakers and for verifying such actions, the applicant stated that these procedures are available.

3 METHODOLOGY REVIEW

The staff used a Markov model to determine the frequencies of maintenance-induced flood initiators resulting from maintenance on various components in ECC or RCIC systems. The staff used another Markov model to determine the frequencies of rupture-induced flood initiators during transients, manual shutdowns, and tests.

The analyses submitted by the applicant assumed that when flood reaches 3 feet-10 inches, all ECC and RCIC system components would fail. The applicant's analysis did not develop the event trees according to the progression of a flood affecting various components at various elevations up to 3 feet-10 inches.

The staff used a time-phased approach to expand the flooding event trees submitted by the applicant into four phases. The four phases correspond to different components at different elevations. On the basis of the flood rates from various systems, times for the floods to reach various elevations were determined. These times correspond to operator response times for different time phases. The time-dependent human error probabilities were obtained from NUREG/CR-1278 using the operator response times. The human error probabilities were used to requantify the event trees for various time phases.

4 UNCERTAINTY ANALYSES

In view of the large uncertainties in the analysis, the staff used the computer program SAMPLE to estimate the core vulnerable frequency initiated by a flood at Shoreham The parameters varied in the SAMPLE analysis included:

(1) pipe break frequency

(2) probability of failure of all equipment attached to a division given a failure of a protective relay in a motor-control center

(3) probability of failure of a protective relay

(4) human error probabilities

   (a) probability of failing to rack out a breaker during maintenance
   (b) probability of failing to notice a flood alarm
   (c) probability of failing to isolate a flood

Some of the uncertainties not included in the SAMPLE analysis are

(1) There is no common-mode failure between different divisions, and no sensitivity analysis was performed to assess the error here.

(2) The conditional probabilities of having a manual trip or a MSIV closure during a flood are subjective and are not varied in the staff analyses. For example, in the staff analysis of time phase 4, a conditional probability of 0.5 is assumed for a MSIV closure. However, the results cannot be nonconservative by more than a factor of 2.

(3) The staff analysis assumes that the Shoreham alarm-response procedures are adequate for proper operator action.

Based on the SAMPLE calculation, the staff estimates that the mean value of the core-vulnerable frequency* due to flooding is 2×10^{-5} per reactor-year, the upper 95% confidence limit is 7.5×10^{-5} per reactor-year, and the lower 5% confidence limit is 2.2×10^{-7} per reactor-year.

The staff notes that the mean value of the core-vulnerable frequency as a result of flooding is about 5 times as large as the applicant's estimate. The discrepancy is mainly the result of the staff's use of higher flood initiator-event frequencies and different approaches (Markov models and time-phased event trees).

5 SUMMARY/CONCLUSION

The staff finds that the mean value of the core-vulnerable frequency as a result of reactor building flooding is 2×10^{-5} per reactor-year. The contribution to this value from maintenance-induced flooding is 7×10^{-6} per reactor-year, and from pipe-break-induced flooding is 1.3×10^{-5} per reactor-year. The upper 95% confidence limit on the core-vulnerable frequency was 7.5×10^{-5} per reactor-year, and the lower 5% confidence limit was 2.2×10^{-7} per reactor-year.

In contrast, the applicant found that core-vulnerable frequency initiated by flooding is about 4×10^{-6} per reactor-year. The contribution to this value from maintenence-induced flooding is 1.5×10^{-6} per reactor-year, and from pipe-break-induced flooding is 2.4×10^{-6} per reactor-year. The staff's estimates are predicated on the assumption that the alarm response procedures are adequate. However, the staff identified some potential deficiencies in these procedures, and the core-vulnerable frequency may be higher than that estimated unless the procedures are corrected.

*The Shoreham PRA defines the core-vulnerable state as an end state of the plant in which the reactor core or containment integrity is challenged. Certain operator actions, including operator actions "in extremis" can be used in a core-vulnerable state to prevent core melt. The Shoreham PRA finds that the overall frequency of core melt is about 50% of the overall core-vulnerable frequency.

6 REFERENCES

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2 Budnitz, R. J. (FRA), letter to H. R. Denton (NRC), "Review and Critique of Previous Probabilistic Accident Assessments for the Shoreham Nuclear Power Station," September 24, 1982.

3 Smith, J. L. (LILCO), letter to H. R. Denton (NRC), "Evaluation of Internal Flooding, Shoreham Nuclear Power Station Unit 1," December 2, 1982.

4 Science Applications, Incorporated, "Final Report - Probabilistic Risk Assessment Shoreham Nuclear Power Station," SAI-372-83-PA-01, June 24, 1983.

5 U.S. Nuclear Regulatory Commission, NUREG/CR-1205, "Data Summaries of Licensee Event Reports of Pumps at U.S. Commercial Nuclear Power Plants: January 1, 1977 to April 30, 1978," U.S. Nuclear Regulatory Commission, January 1980.

6 U.S. Nuclear Regulatory Commission, NUREG/CR-1205, Revision 1, "Data Summaries of Licensee Event Reports of Pumps at U.S. Commercial Nuclear Power Plants: January 1, 1972 to September 30, 1980," January 1982.

7 U.S. Nuclear Regulatory Commission, NUREG/CR-1363, W. H. Hubble and C. Miller, "Data Summaries of Licensee Event Reports of Valves at U.S. Commercial Nuclear Power Plants," June 1980.

8 U.S. Nuclear Regulatory Commission, NUREG-75/014, "Reactor Safety Study"; formerly published as WASH-1400, December 1975.

9 U.S. Nuclear Regulatory Commission, NUREG/CR-1278, A. D. Swain and H. E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," April 1980.

LETTER REPORT ON THE
REVIEW OF THE SEQUENCES
FOLLOWING A RELEASE OF EXCESSIVE WATER IN
ELEVATION 8 OF THE REACTOR BUILDING IN THE
SHOREHAM NUCLEAR POWER STATION

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ABSTRACT

The core vulnerable risk resulted from Reactor Building flooding events is addressed as a part of the SNPS PRA.(1) The analysis was reviewed and re-evaluated at BNL and the results are presented in this report. The BNL review includes both qualitative and quantitative analyses of flooding initiators, operator errors, and accident sequences which result in a vulnerable core state. An estimate of the uncertainty for the core vulnerable risk is also included.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF FIGURES (Cont.)

LIST OF TABLES

1.0 INTRODUCTION

At the Shoreham Nuclear Power Station (SNPS) the majority of safety-related equipment are located in the Reactor Building (RB). The Shoreham Reactor Building is a cylindrical building surrounding the MARK II containment structure. Water leakage from equipment in the reactor building will drain to Elevation 8 (the lowest level of the RB) via openings and stairwells since there is no structural separation between safety systems. Flooding of the Elevation 8 compartment may potentially disable all the ECCS because they are located in the Elevation 8 compartment.

The SNPS-PRA[1] has included flooding as a common-mode event which may disable the ECCS equipment. The SNPS PRA assumes that a critical flooding depth of 3'-10" from the RB floor will disable all the ECCS equipment. Operator diagnosis and isolation of the flooding before it reaches 3'-10" depth is considered in SNPS-PRA.

Because of the potentially significant impact, the SNPS's evaluation of the core melt risk due to RB flooding warrants a special review. A field trip to the Shoreham plant has been made by BNL personnel for obtaining detailed information on the equipment and power control layouts in the RB, especially in the Elevation 8 compartment. BNL has determined that there are three flooding depths (1'-3", 1'-10", and 3'-10") that are critical to the availability of various ECCS equipment. The initiator event trees are thus revised accordingly.

BNL also identified that the random failure of a equipment protection circuit breaker coinsiding with the RB flood event may cause the propagation of failures to equipment powered by separated Motor Control Centers (MCC). This potential common mode failure event has also been modeled in BNL event trees.

Shoreham Plant Procedure Guides relevant to the RB flooding have been reviewed by BNL. BNL found that these procedure guides fail to require a systematic check of system parameter indicators in the control room following a RB Flooding Alarm annunciation. This may cause the operator to ignore an abnormal system parameter, especially under a multiple alarm situation (such as a turbine trip).

BNL's revised event trees, quantitative evaluation of core vulnerable risk due to RB flooding events, and an uncertainty estimate for the core vulnerable risk are presented in this report.

The report is organized as follows: Section 2 summarizes the SNPS-PRA approach to the flood sequence identifications and quantification. Section 3 presents the BNL revision both in the methodology and in the quantification. Finally, Section 4.0 summarizes the results.

2.0 SNPS METHODOLOGY AND ANALYSIS

2.1 Overview

The SNPS methodology for determining the contribution to the risk of the internal floods can be divided into three steps.

1. Identification of water sources and pathways to Elevation 8 compartment.
2. Evaluation of operators responses and assessment of likelihood of arresting the flood.
3. Evaluation of system responses and identification of the sequences leading to a core vulnerable state given a flood.

In the Shoreham PRA approach it was determined that flooding at locations other than Elevation 8 would be bounded by the analysis of flooding at the lowest level of the reactor building Elevation 8, since the flood water will drain and cascade down to that level through stairwells and openings. All the evaluations of flood are hence focused on equipment at the Elevation 8 level.

The volume of water required to flood the reactor building Elevation 8 compartment, with all equipment and piping installed, is estimated to be 41,600 gallons in SNPS-PRA for each foot of depth. The following drainage systems are available to receive the initial volume of flood water:

- Reactor Building Floor Sumps
- Reactor Building Equipment Sumps
- Reactor Building Porous Concrete Sumps.

These systems have total sump capacity of 4,650 gallons, and total sump pump capacity of 640 gallons per minute, however, they are not included in the analysis.

The potential water sources which may release excessive water in Elevation 8 are summarized in Table 2.1.1. For each of these sources, a pathway investigation has been performed in the SNPS-PRA, to define the potential for flood at Elevation 8. Table 2.1.2 summarizes the water sources as evaluated in the Shoreham PRA. For each water source the largest possible flow rate has been determined and the time required for the flood to reach the 3'-10" level in Elevation 8, have been estimated. These times are also given in Table 2.1.2. These times provide the basis for estimating the probability of successful prevention of flood at the 3'-10" level by operator actions.

A survey of all vital equipment by Shoreham identified a number of components for the various accident mitigation systems which could potentially be submerged in the event of an internal flood. Based on this information, the critical height of 3'-10" was defined. It was assumed that if flood water exceeds the 3'-10" level, all ECCS equipment would be disabled. Flooding scenarios which are arrested before reaching the 3'-10" level, have been found to contribute negligibly in the core damage frequency.

Functional event trees were used in the Shoreham internal flood PRA to model the plant response given an internal flood initiator. The flood initiator frequency was calculated based on two types of internal flood precursors: online maintenance and rupture of piping, valves or pumps. These precursor frequencies are described in Section 2.2. Given the occurrence of these flood precursors, the progression of events was modeled using initiator event trees. Details of the initiator event trees are presented in Section 2.3.

Since all the ECCS systems are assumed lost given a 3'-10" flood, the only available means for cooling the core are the feedwater and the condensate pump injection. The availability of these two systems depends on the state of the MSIVs and on the ultimate source of the flood (condensate storage tank or suppression pool).

Because of these dependences, the end states of the initiator event trees were classified into six categories each of which becomes the entry condition for the functional event trees. Table 2.1.3 summarizes the information in a matrix form. Each row of the matrix depicts one of the 17 types of internal flood precursors, the columns represent the six entry conditions to the functional event trees. The six entry conditions can be grouped into manual shutdown, turbine trip and MSIV closure. Two possible entry conditions are considered for each of these three initiators: flooding due to water from the condensate storage tank (CST) and flooding due to water from other sources.

Based on these six entry conditions, six functional event trees were developed. An example is given in Figure 2.1.1.

2.2 SNPS-PRA Quantification of the Frequency of Flood Initiators

Two types of flood initiators were considered in the SNPS-PRA.

1. Floods initiated by an accidental loss of isolation (valve opening) while a component in the Elevation 8 area is dismantled for maintenance.
2. Floods initiated by a rupture in the pressurized or the non-pressurized part of the piping.

2.2.1 Maintenance-induced Flood Initiators

The frequency of the first type of initiator was calculated by estimating the frequency of maintenance of various components based on operating experience data. The LER data base in Ref.2 identifies the observed failures from turbine-driven and motor-driven pump failures. The data used in the SNPS-PRA are summarized in Table 2.2.1. There are four failure modes for pumps, i.e., leakage/rupture, does not start, loss of function, and does not continue to run. The hourly LER failure rates characterize the leakage/rupture failure mode, while demand failure rates consider other failure modes.

The following LER rates are found for the four failure modes in motor-driven and turbine-driven standby pumps.

Motor Driven Pumps

- Leakage/rupture: 6 events/6,777,627 hrs. = 8.9×10^{-7}/hr.
- Does not start, loss of function, and does not continue to run: (5+4+6) events/(13,644 demands) = 1.1×10^{-3}/demand

SNPS-PRA assumed that these pumps are in standby status until there is a demand. The number of demand used in SNPS-PRA are 12 on the average per year (four scheduled tests plus eight other occurrences). Hence, the maintenance frequency for motor driven standby pumps per year is calculated as

$(8.9 \times 10^{-7}$ failure/hr)*(24 hr/day)*(365 day/yr) +
$(1.1 \times 10^{-3}$/demand)*(12 demands/yr) = 2.0×10^{-2} failure/year.

Turbine Driven Pump

Similiarly, the maintenance frequency for turbine driven standby pumps per year is calculated as 0.079 failure/year.

There are two motor driven pumps associated with the Core Spray System, four motor driven pumps with the LPCI System, and four motor driven pumps associated with the Service Water System in which two are linked as a pair to the RHR Heat Exchanger System. There is only one turbine driven pump associated with the HPCI System and one with the RCIC System. Table 2.2.2 summarizes the SNPS-PRA frequencies associated with major maintenance operations based upon the above evaluation and a conservative estimate of heat exchanger online maintenance.

2.2.2 Rupture-Induced Flood Initiators

The frequencies of the initiators caused by loss of system integrity from breaks or ruptures were derived from WASH-1400 failure rates of major components involving external leak and external ruptures, based on assumptions made in NUREG/CR-1363 (Reference 3). This information has been summarized in Table 2.2.3.

The calculation of each initiator is done by identifying the appropriate type and length of piping and number of components susceptible to rupture and summing the estimated yearly rupture rates. As an example, the total number of valves involved in the HPCI discharge system are 3 (2 MOV's and 1 Check Valve); there is no pump involved (Table 2.2.5) and the total length of piping is 76'. Referring to Table 2.2.3, the rupture failure rate for 100' of pipe section is 4.3×10^{-11}/hr, and for external failure of a valve is

1.3×10^{-9}/hr. The total length of pipe in the HPCI Discharge System is estimated to be 76' (Table 2.2.5).

$$(3 \text{ valves})*(1.3\times10^{-9}/\text{hr}) + 76'/100' \ (4.3\times10^{-11}/\text{hr})$$
$$= 3.9\times10^{-9}/\text{hr or } 3.5\times10^{-5}/\text{yr}.$$

Since the flow rates through suction line breaks are time dependent (i.e., a function of the varying water head in the source) and a strong function of the break shape and size, a simplified model based on historical experience and engineering judgement is used in the Shoreham PRA to describe the conditional probability of break size. Table 2.2.4 summarizes the classes of break size examined.

These probabilities, are combined with the frequencies estimated for initiators associated with core spray, HPCI, RCIC, LPCI, and Service Water Rupture/Leak Suction System failure to obtain the initiating event frequencies for non-pressurized piping. Table 2.2.6 summarizes the frequencies of initiators due to the loss of system integrity from breaks or ruptures.

2.3 Initiator Event Trees

The probability of causing a flood due to component under maintenance or the probability of not arresting the flood is calculated with the help of initiator Event Trees. These trees are shown in Figures 2.3.1 through 2.3.17. A discussion of the P, D, E, I, and A events in the event trees follows.

a. Event P - Operator removes power from equipment and valves.
   The removal of power from equipment and its isolation valves is a required procedure during a maintenance in both fossil and nuclear power stations. The equipment and isolation valves are electrically disconnected from their associated power supply by pulling and tagging the appropriate breaker at the MCC. A second qualified person verifies the correct implementation of the tagging order and placement of the clearance tags.

   A human error probability (HEP) of 0.01 is assigned for this operator action. This value is determined using the probability data given in NUREG/CR-1278[4] (p.20-23).

b. Event D - System not demanded.
During the maintenance process there is a possibility that the safety systems will be demanded because of a transient challenge. Isolation valves will automatically open if the operator has failed to remove power from the isolation valves (Event P).

c. Event E - Operator maintains isolation.
During on-line maintenance with the equipment disassembled, the isolation valves need to be maintained in closed position throughout the duration of the maintenance process. However, an operator error could inadvertently open isolation valves.

SNPS concludes that it is unlikely that the operator will manually open these valves locally in the RB and fail to notice the flood. Opening of the isolation valves at the MCC is also concluded by SNPS to be unlikely.

The remaining possibility is that the valve is opened from the control room (given Event P). The panel switch could be activated by three events. These events are: the operator mistakenly operates the switch; a command fault to the valve; or the operator inadvertently operates the switch. The probabilities for these events are 10^{-3}, 10^{-4}, and 10^{-2}, respectively.

d. Event I - Flood annunciation.
The excessive water in reactor building is annunciated by alarms in the control room. The probability of the operator to fail to notice the alarm (the light is in a "back" panel) is assessed at 10^{-3}.

e. Event A - Operator diagnoses and responds to isolate the flood.
The operator must identify the source of and isolate the flood before it reaches the 3'-10" level. This event is considered by SNPS under two conditions as follows.

1. Operator isolates flood after auto occurrence, e.g., turbine trip or MSIV closure (Event A_A). Multiple alarms will occur in the control room at the same time as the flood alarm.

2. Operator isolates flood after manual occurrence, e.g., power operation or manual shutdown (Event A_M). Only the flood related alarms will annunciate in the control room.

The HEP data provided in NUREG/CR-1278[4] (1982 Edition, Chapter 12) are applied by SNPS for their evaluation. Figure 2.3.18 and Table 2.3.1 show the time varying cumulative HEP for both the single and the multiple occurrence conditions.

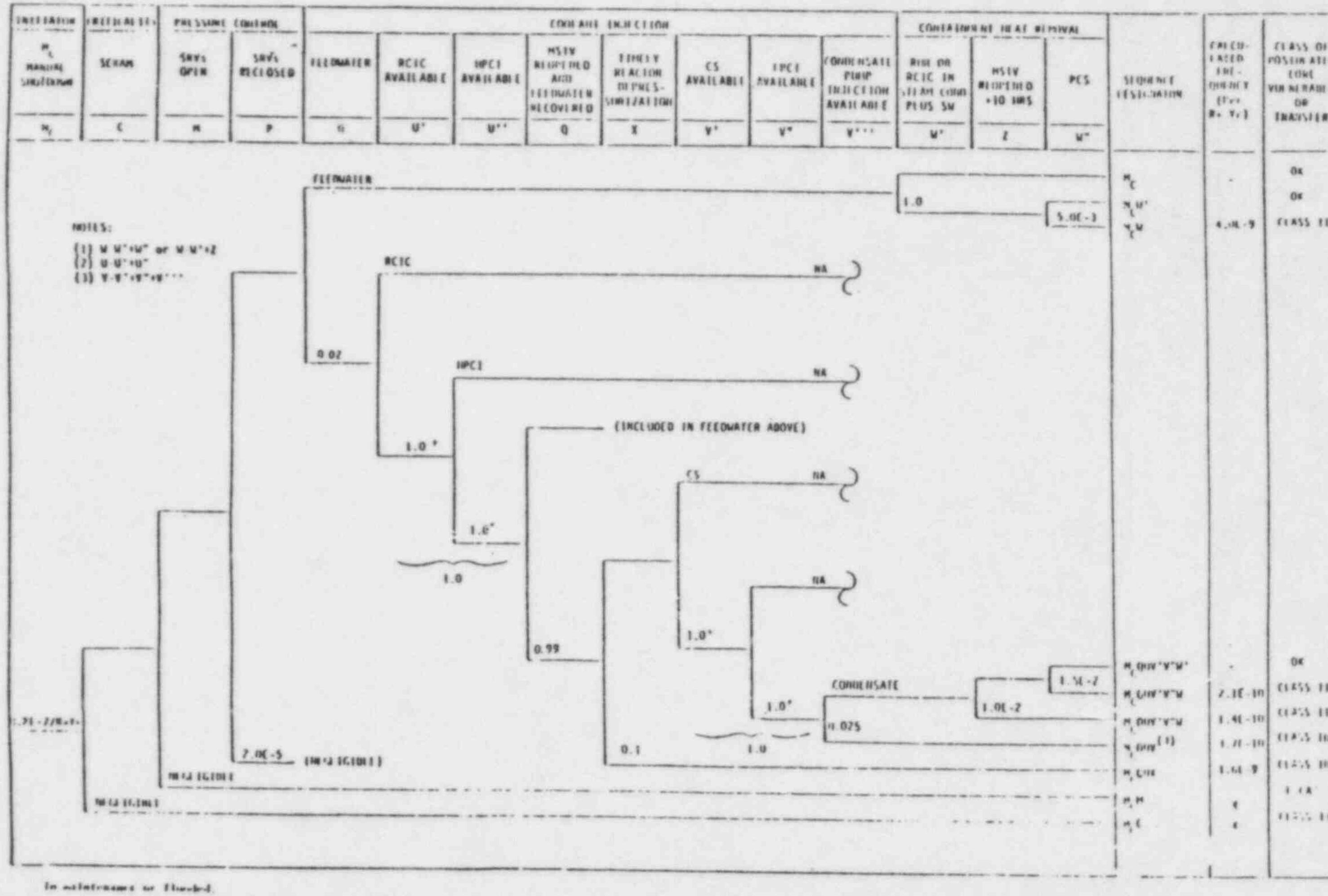


Figure 2.1.1 System Event Tree for Manual Shutdowns With Greater Than 3'-10" of Water in the Reactor Building (Source = CST).

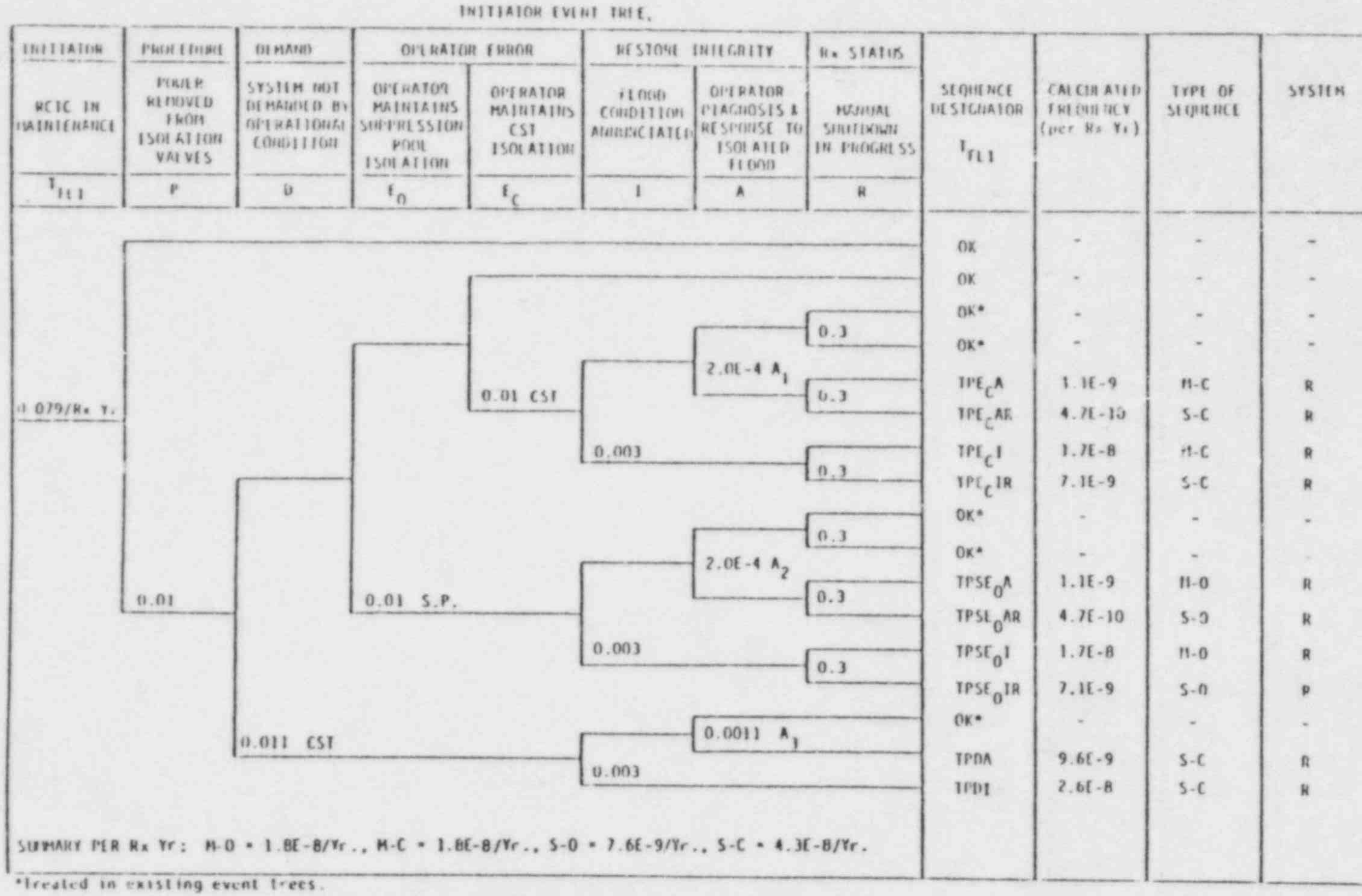


Figure 2.3.1 T_{FL1}: Initiator Event Tree for Postulated Flooding Sequences Initiated During RCIC Maintenance

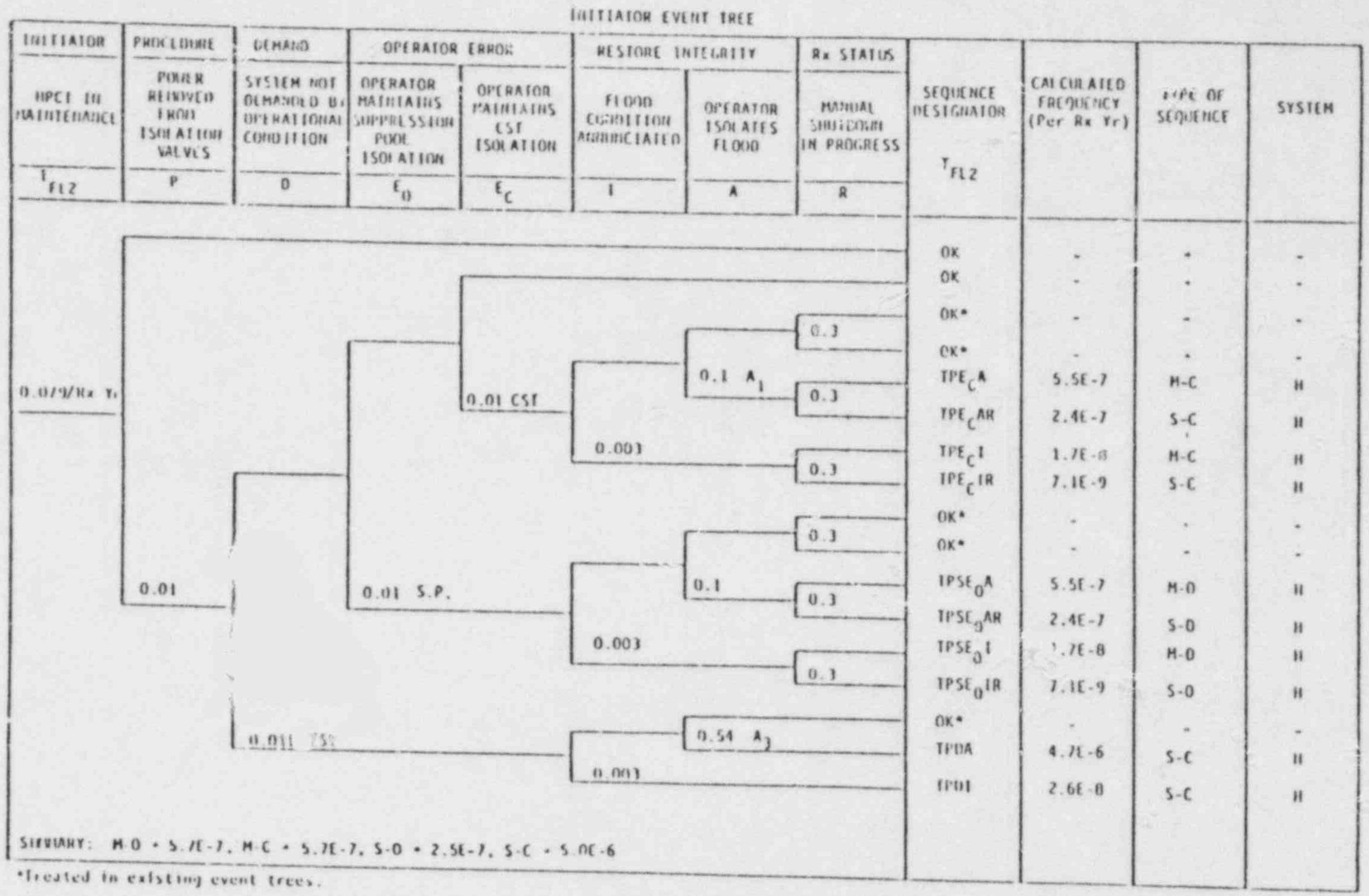
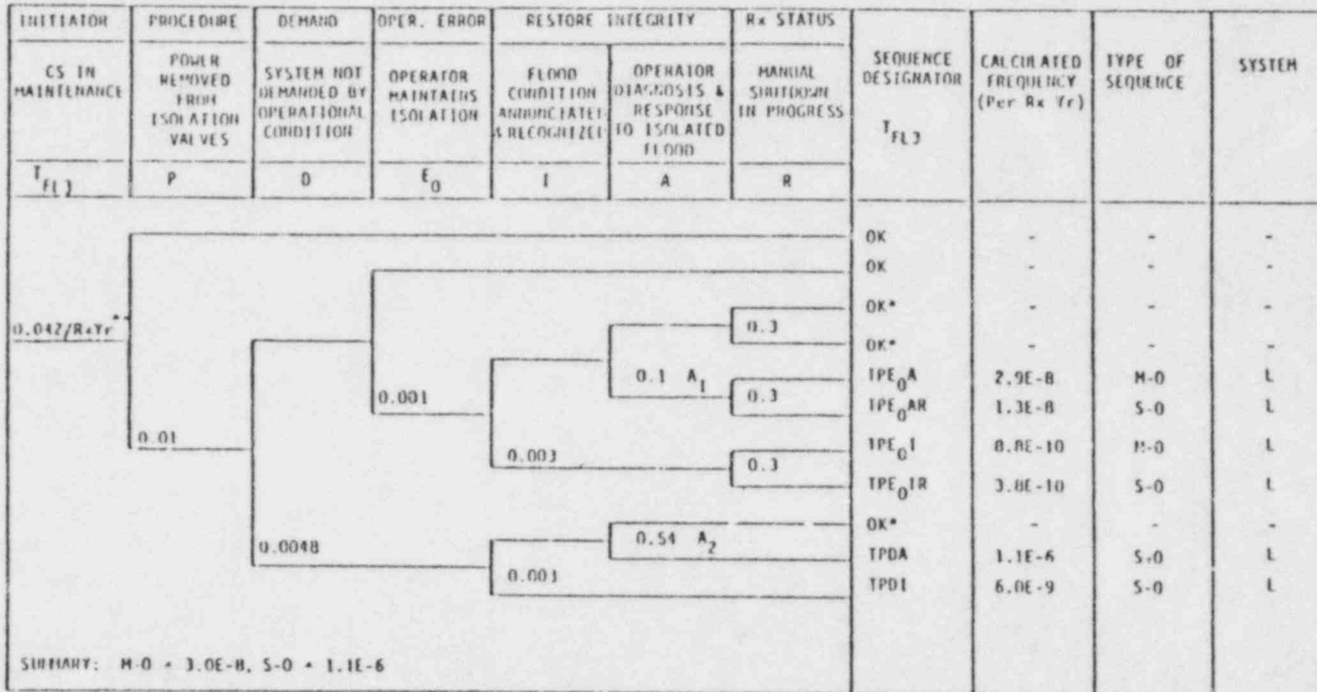


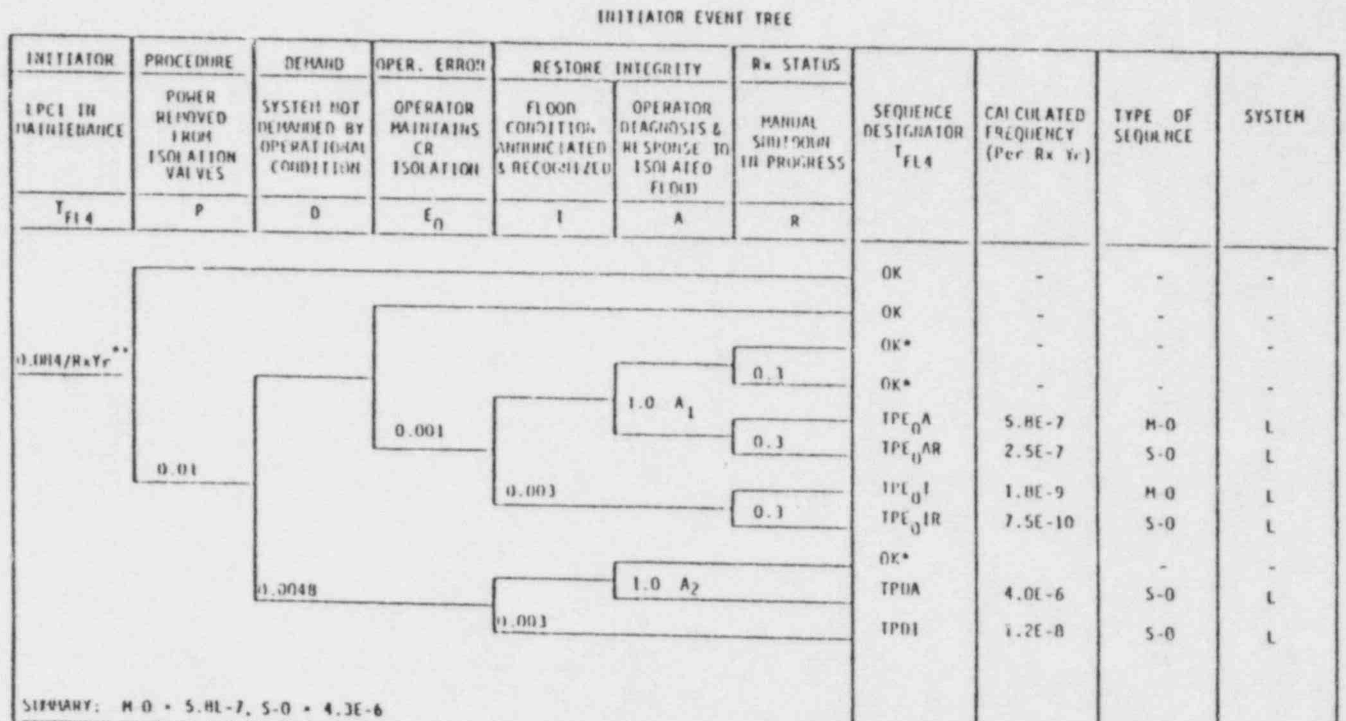
Figure 2.3.2 T_{FL2} - Initiator Event Tree for Postulated Flooding Sequences Initiated by an Error During HPCI Major Maintenance

INITIATOR EVENT TREE



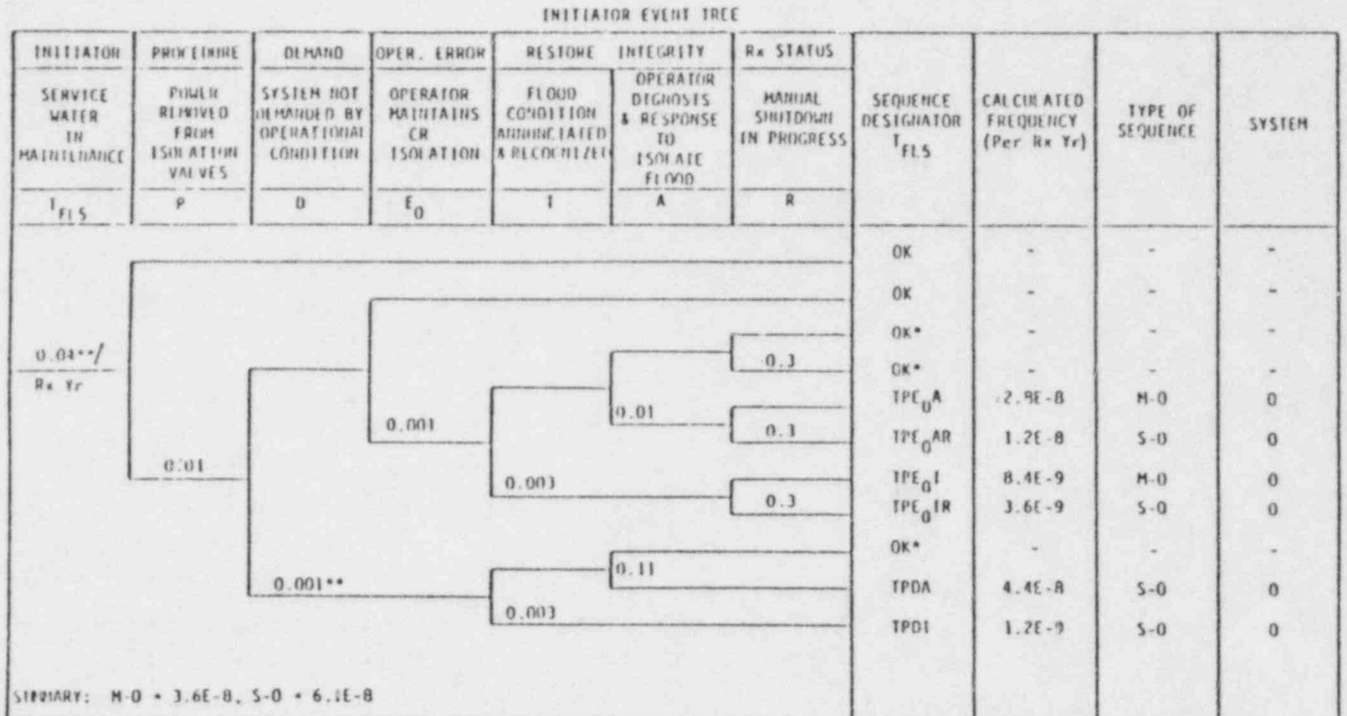
* Treated in existing event trees.
**Includes both CS pumps.

Figure 2.3.3 T_{FL3} - Initiator Event Tree for Postulated Flooding Sequences Initiated by an Error During Core Spray Major Maintenance



* Treated in existing event trees.
**Includes four LPCI pumps.

Figure 2.3.4 T_{FL4} - Initiator Event Tree for Postulated Flooding Sequences Initiated by an Error During LPCI Major Maintenance



* Included in existing event trees.
**Included both service water loops.

Figure 2.3.5 T_{FL5} - Initiator Event Tree for Postulated Flooding Sequences Initiated by an Error During Service Water Major Maintenance (i.e., Heat Exchangers)

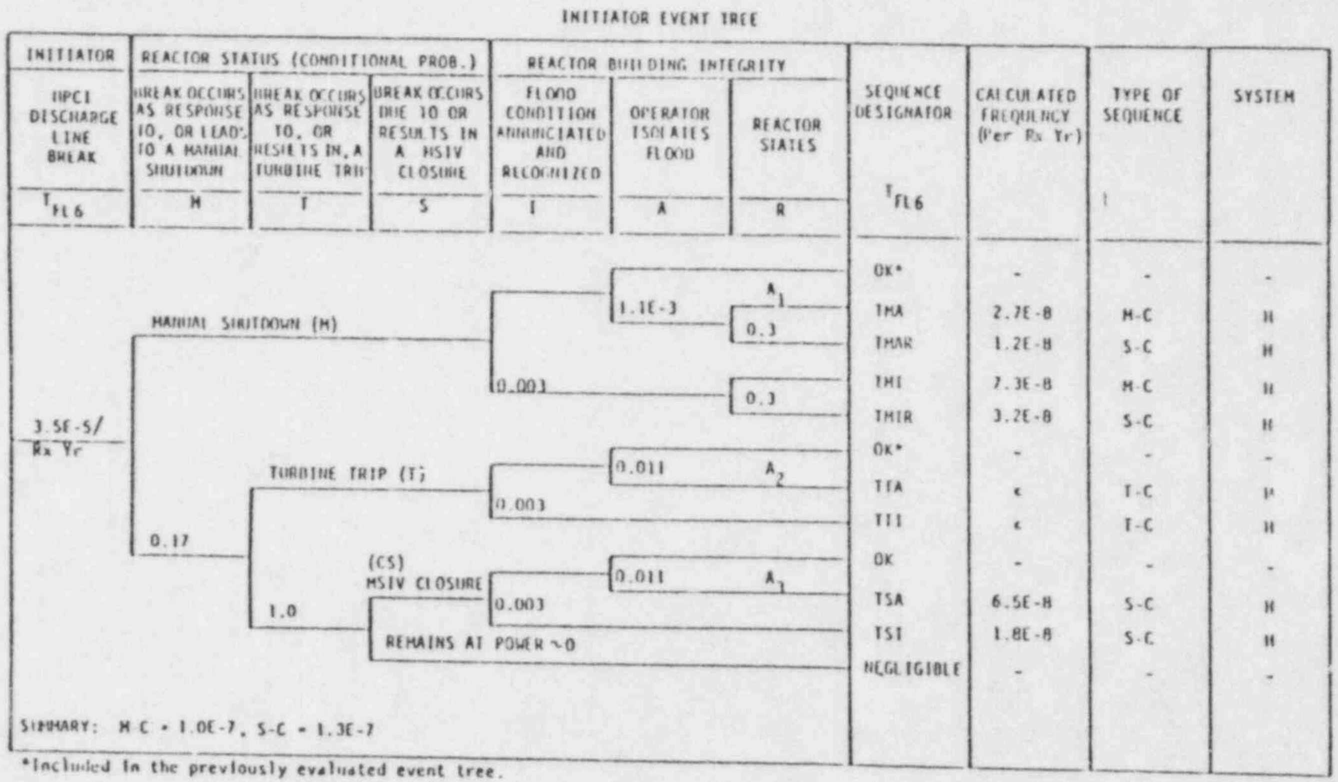
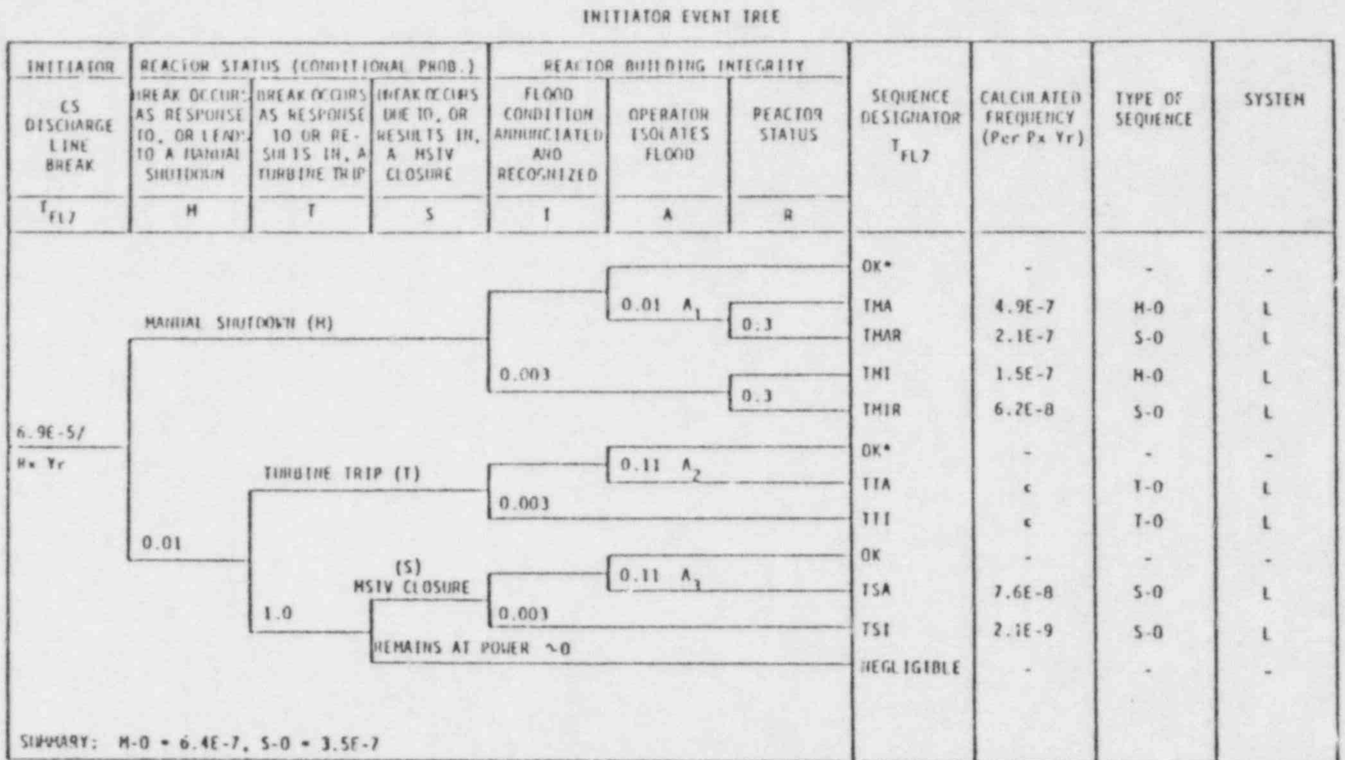


Figure 2.3.6 Initiator Event Tree for Postulated Flooding Sequences Initiated by a HPCI Discharge Pipe Break



*Included in the previously evaluated event tree.

Figure 2.3.7 Initiator Event Tree for Postulated Flooding Sequences Initiated by a CS Discharge Pipe Break

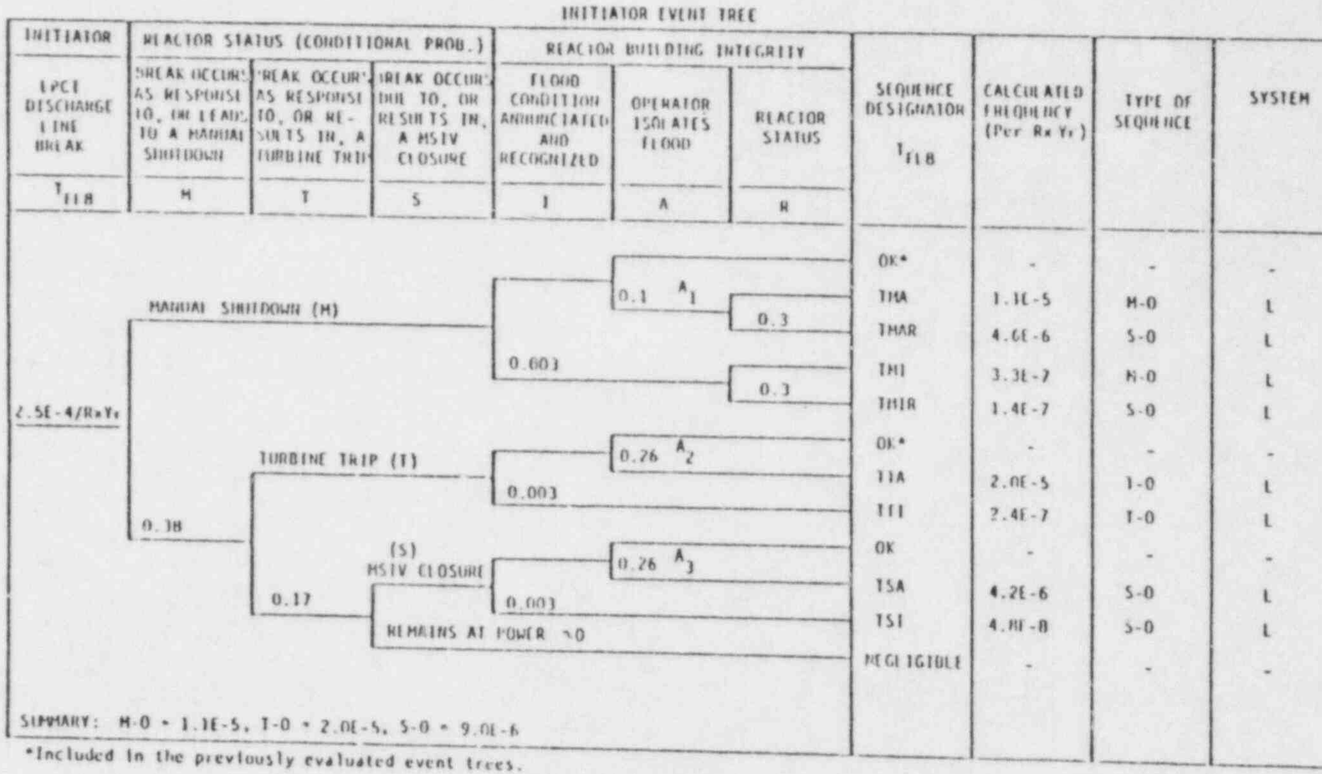
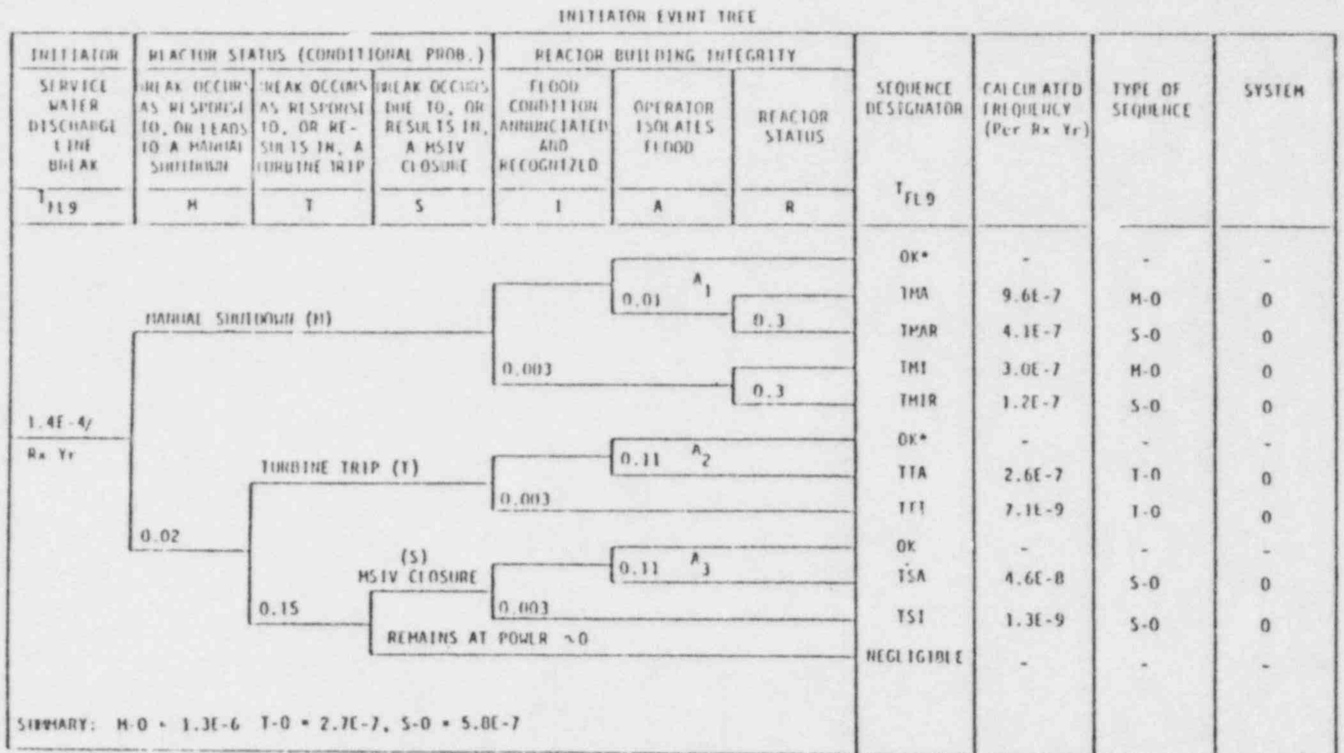


Figure 2.3.8 Initiator Event Trees for Postulated Flooding Sequences Initiated by a LPCI Discharge Pipe Break



*Included in the previously evaluated event trees.

Figure 2.3.9 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Service Water Line Break

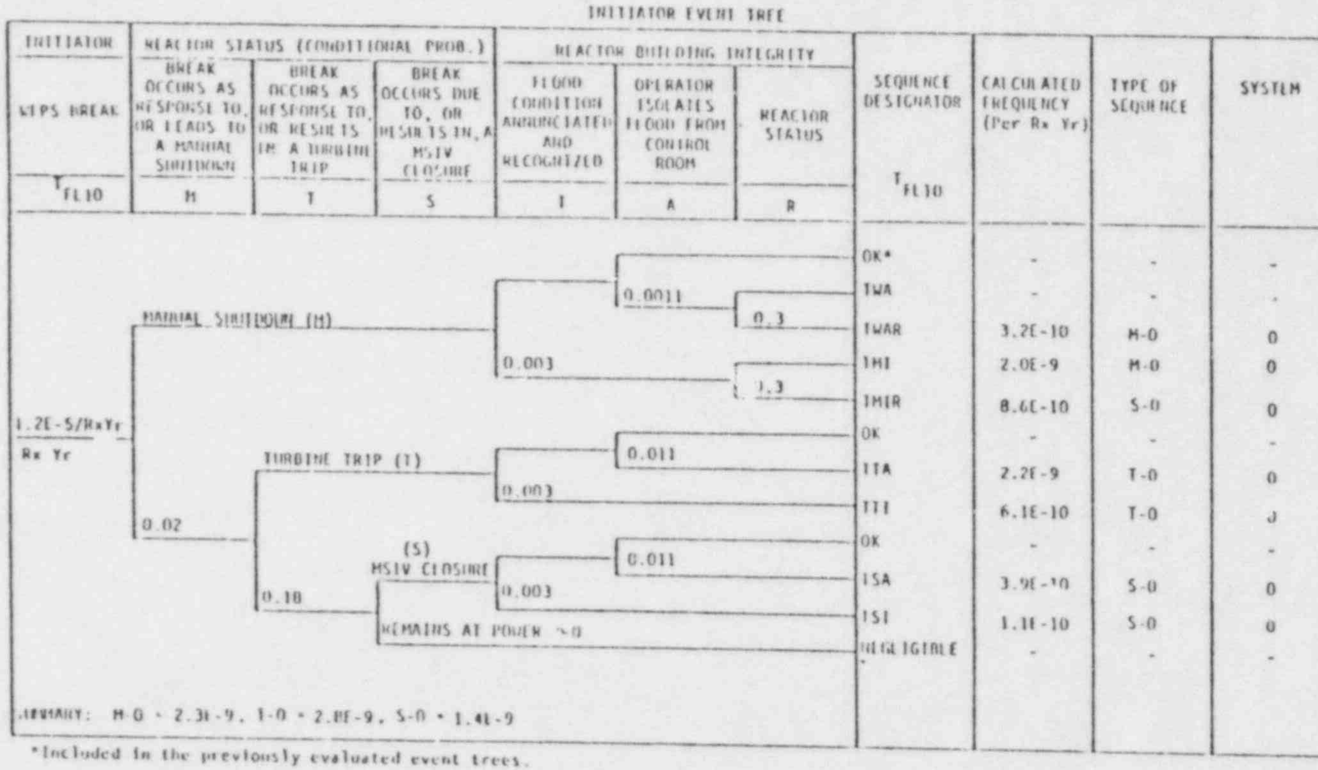


Figure 2.3.10 Initiator Event Tree for Postulated Flooding Sequences Initiated by a WFPS Break

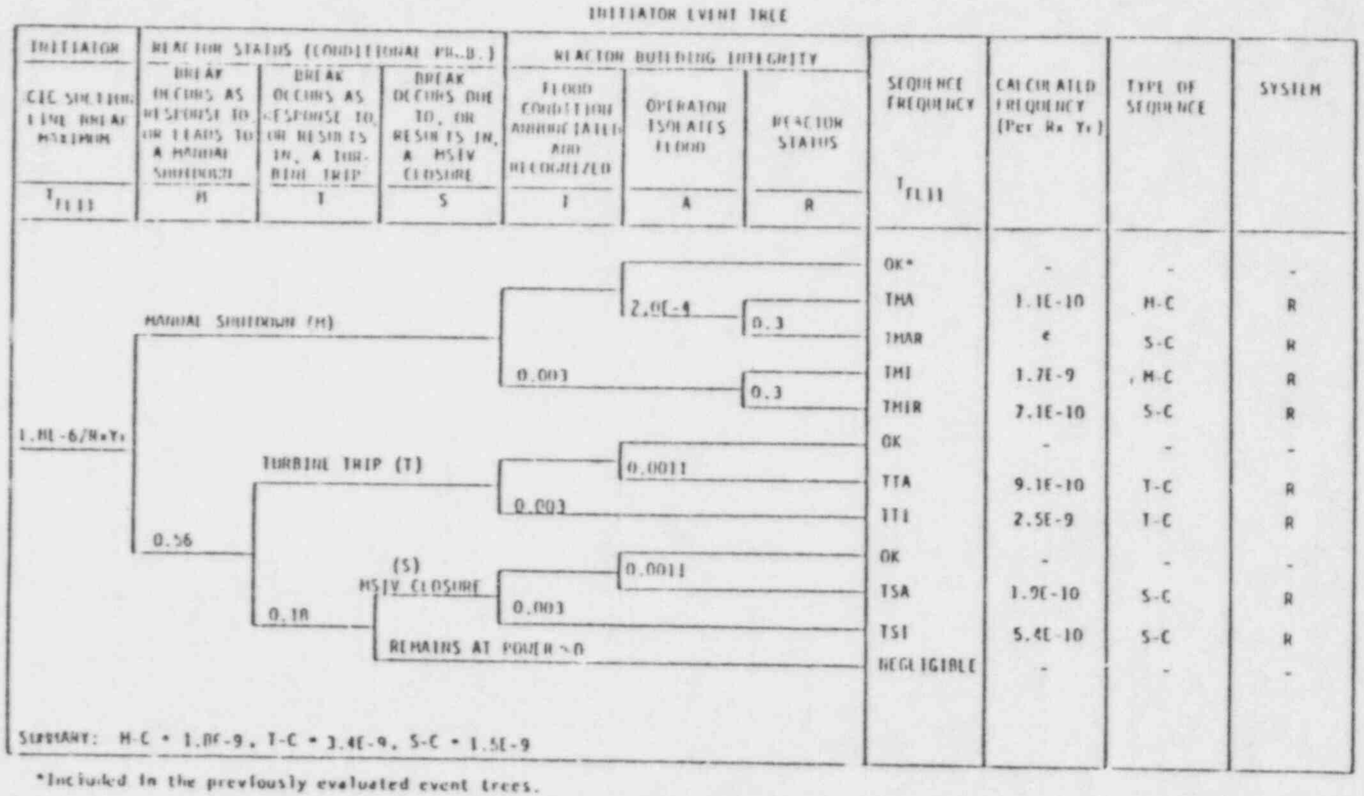


Figure 2.3.11 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Maximum RCIC Suction Line Break

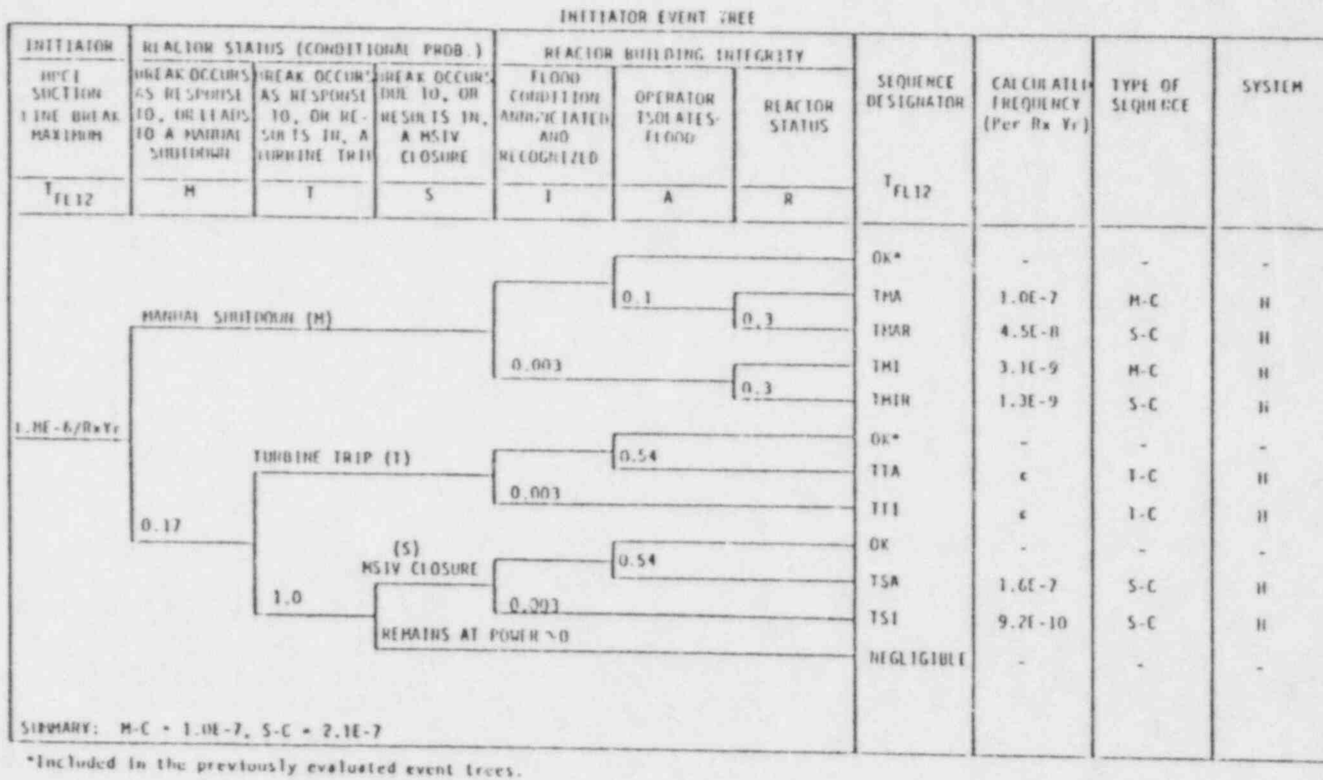


Figure 2.3.12 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Maximum HPCI Suction Line Break

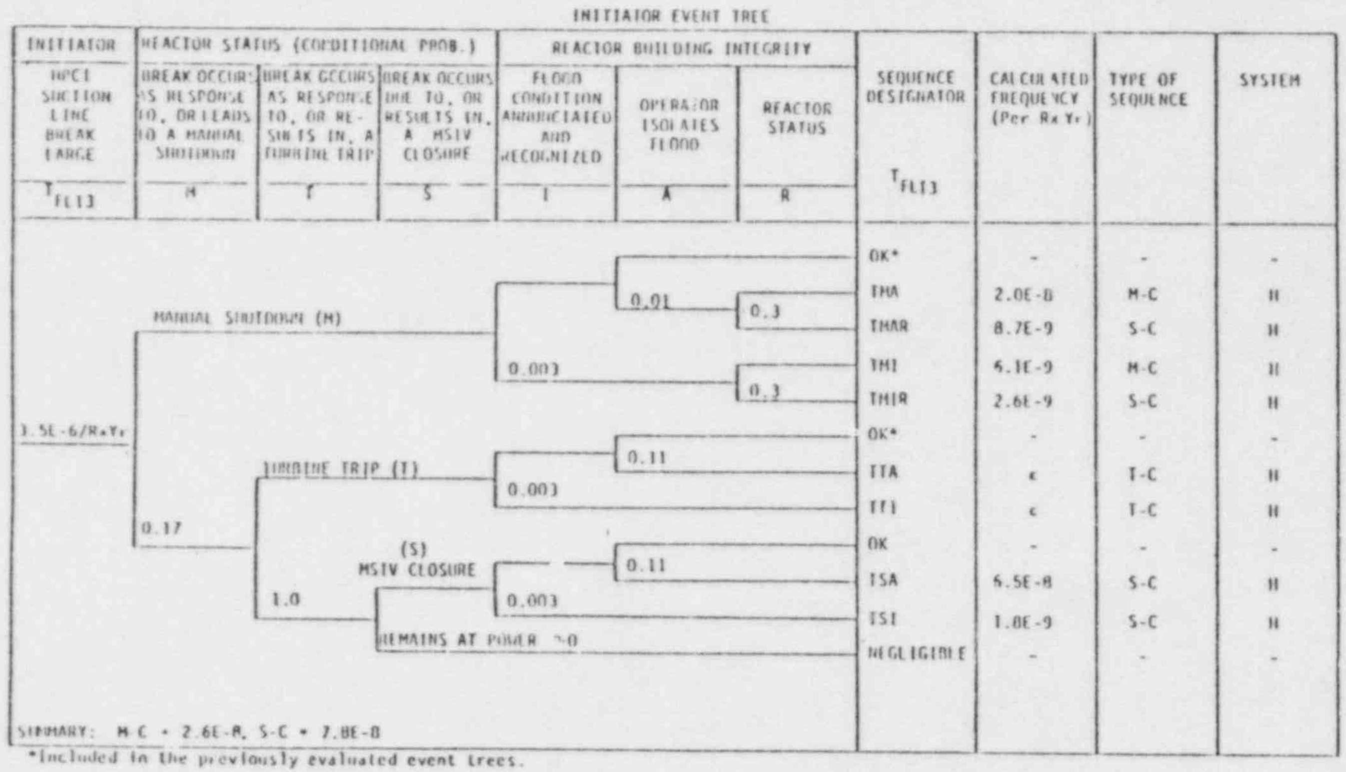


Figure 2.3.13 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Large HPCI Suction Line Break

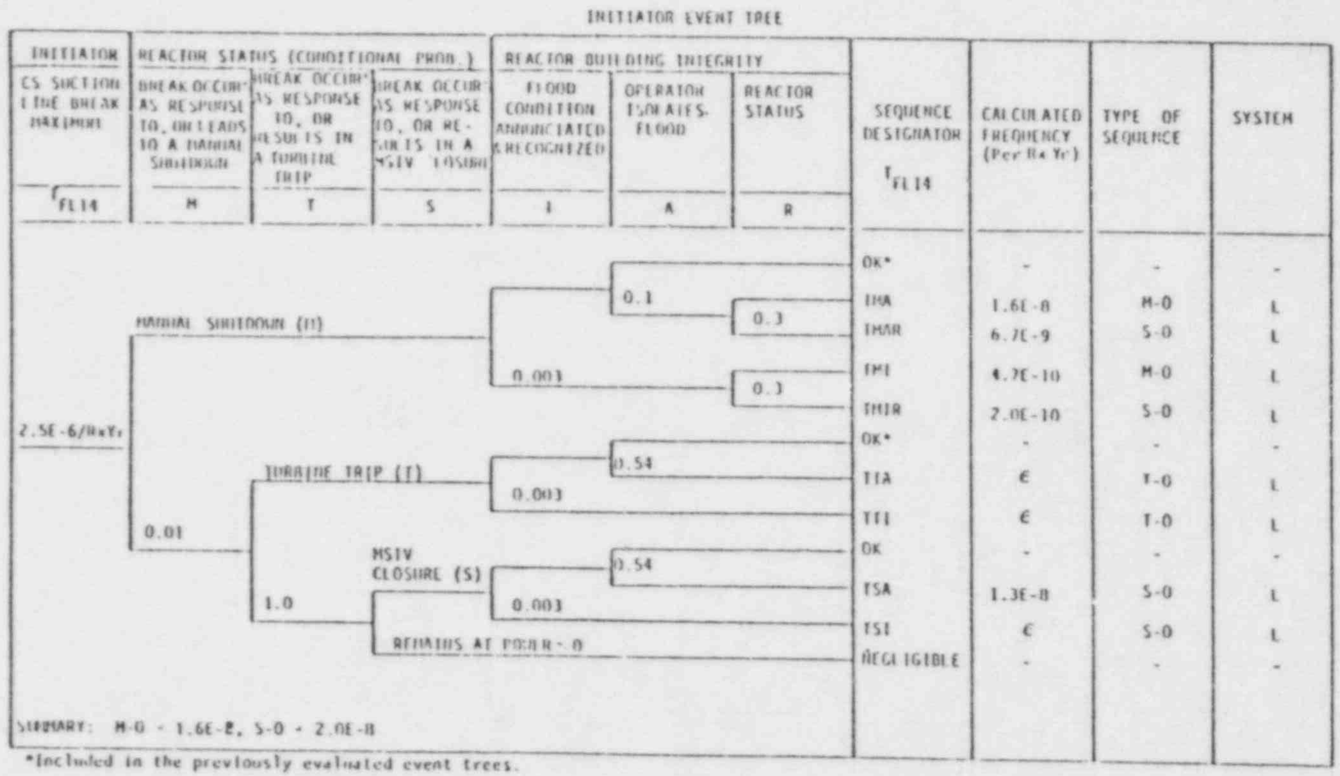
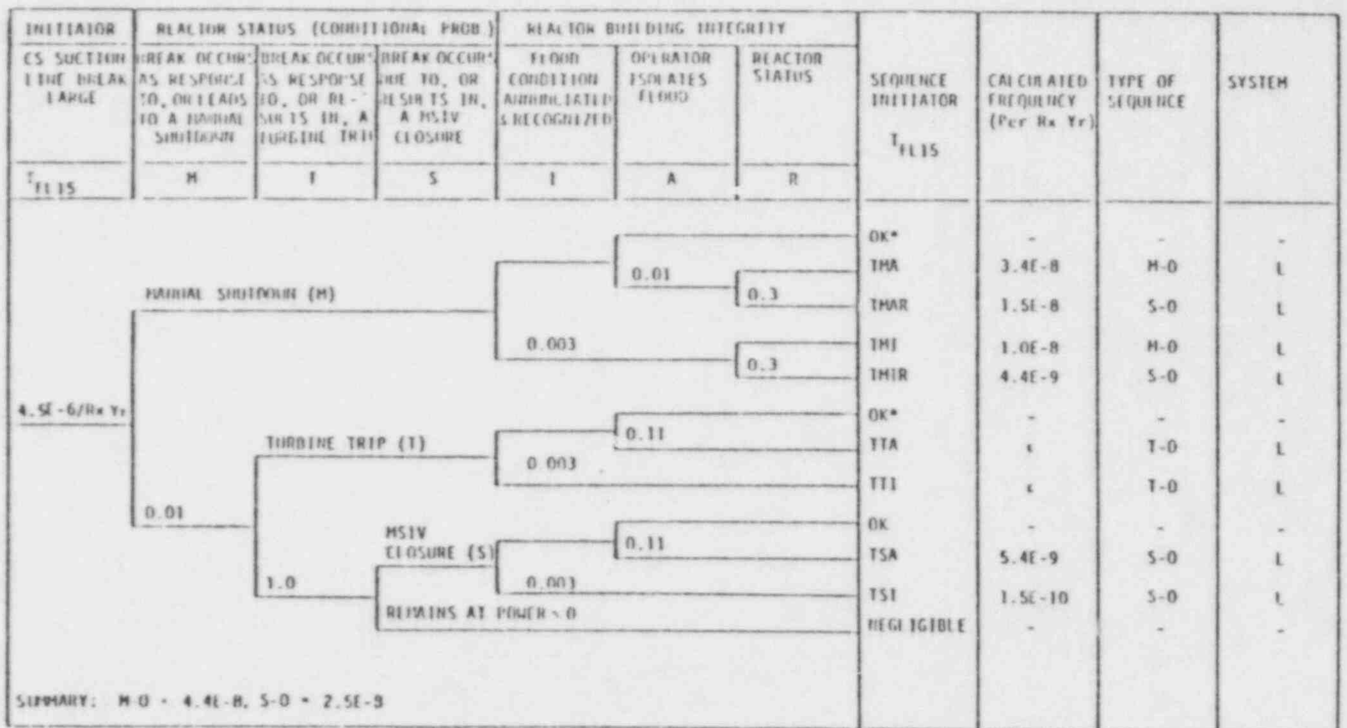


Figure 2.3.14 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Maximum Core Spray Suction Line Break

INITIATOR EVENT TREE



*Included in the previously evaluated event trees.

Figure 2.3.15 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Large Core Spray Suction Line Failure

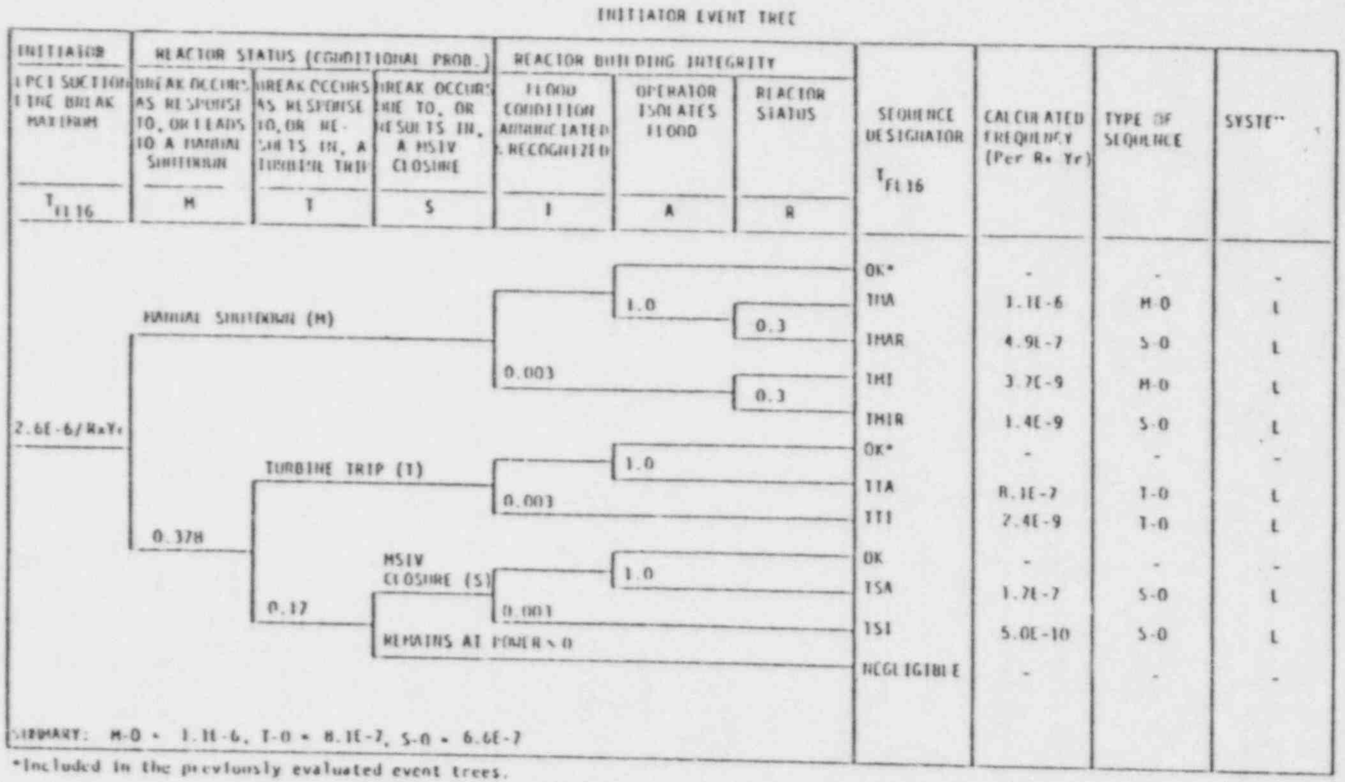


Figure 2.3.16 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Maximum LPCI Suction Line Break

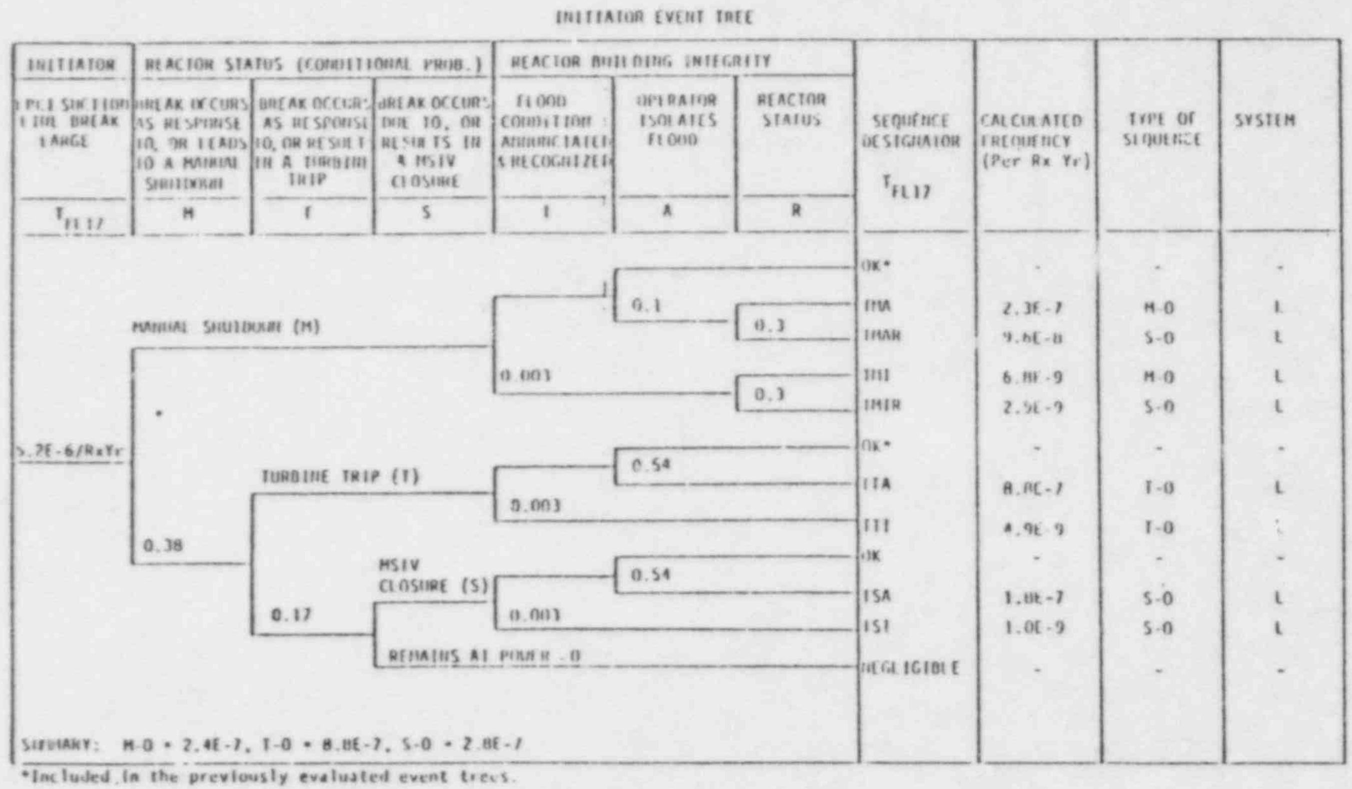


Figure 2.3.17 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Large LPCI Suction Line Break

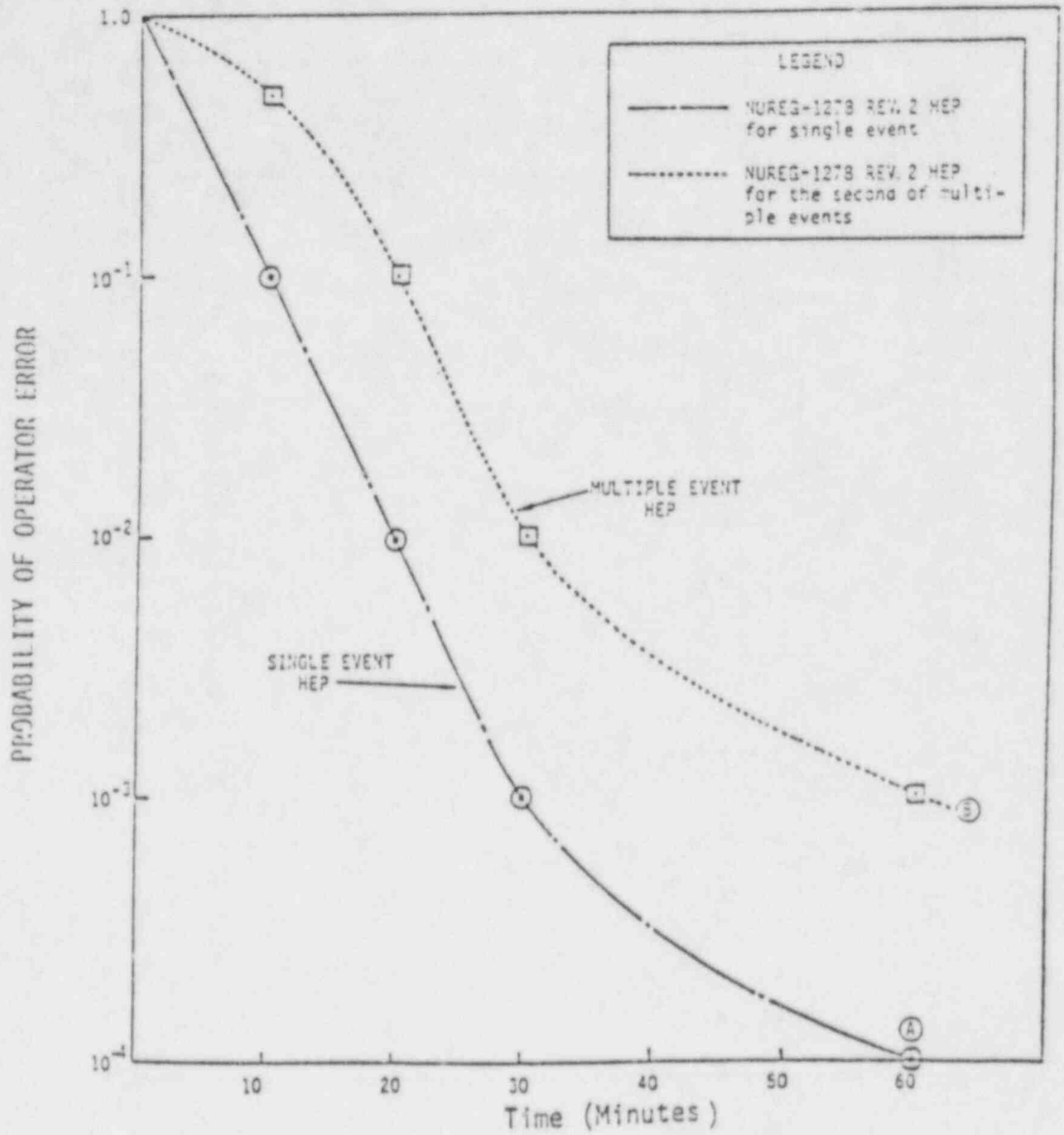


Figure 2.3.18 Comparison of the HEPs Associated with Operator Actions for Singular Events and Coincident Multiple Events

Table 2.1.1 Summary of Potential Water Sources and Types of Initiators Which may Lead to Release of Excessive Water in the Elevation 8 Compartment

Source	Quantity (Gallons)	No. of Lines	Systems Involved
Suppression Pool	160,000*	8	CS,LPCI,RCIC,HPCI
Condensate Storage Tank (CST)	550,000	4	CS,HPCI,RCIC
Reactor Primary System**	a) 42,928 b) 152,928		
Screenwell (Long Island Sound)	Unlimited	4	Service Water
Water Fire Protection System Storage Tank	600,000	Many	Fire Main

*Total water volume in the suppression pool at the high water level mark is 608,500 gallons. However, only a portion of the water can be drained through ECCS pump suction piping.

**Figure (a) includes water from the bottom of the core to normal water level in the RPV. Figure (b) includes (a) plus condenser hotwell water.

Table 2.1.2 Summary of Internal Flooding Initiator Types: Source, Pathway, Flowrates, and Time to Critical Flooding Depth

Source	Location	Flow Rate gpm*	Elevation 8 Flooding Time (Minutes*) 3'-10"
Suppression Pool	HPCI Pump Suction	9600	17.6
	RCIC Pump Suction	1500	10.6
	LPCI Pump Suction (Max/Large)**	17000/8500	9.4/19.0
	CS Pump Suction	13000	12.0
	LPCI Pump Suction	10500 (1 Pump Runout)	15.0
	CS Pump Discharge	6850 (1 Pump Runout)	23.0
Condensate Storage Tank (CST)	HPCI Pump Suction (Max/Large)**	1200/6000	13.0/27.0
	RCIC Pump Suction	2100	76.0
	CS Pump Suction (Max/Large)**	1200/6000	13.0/27.0
	HPCI Pump Discharge	4350 (Design)	37.0
Service Water	RHR Heat Exchanger	8000 (Pump Runout)	20.0
WFPS	Rupture of 8" Pipe	4000	40.0

*These flood times were calculated based on a failure of the sump pumps to successfully operate and a 41,600 gallon per foot depth in the reactor building given in the Shoreham FSAR.

**Large flow rates assumed to be 1/2 maximum flow.

Table 2.1.3 Summary of System Event Tree Entry States by Initiator Type

INITIATOR	SYSTEM EVENT TREE ENTRY CONDITION FREQUENCY (Per Rx Yr)					
	M-O	M-C	T-O	T-C	S-O	S-C
T_{FL1}	1.8×10^{-8}	1.8×10^{-8}			7.6×10^{-9}	4.3×10^{-8}
T_{FL2}	5.7×10^{-7}	5.7×10^{-7}			2.5×10^{-7}	5.0×10^{-6}
T_{FL3}	3.0×10^{-8}				1.1×10^{-6}	
T_{FL4}	5.0×10^{-7}				4.3×10^{-6}	
T_{FL5}	3.6×10^{-8}				6.1×10^{-8}	
T_{FL6}		1.0×10^{-7}				1.3×10^{-7}
T_{FL7}	6.4×10^{-7}				3.5×10^{-7}	
T_{FL8}	1.1×10^{-5}		2.0×10^{-5}		9.0×10^{-6}	
T_{FL9}	1.3×10^{-6}		2.7×10^{-7}		5.8×10^{-7}	
T_{FL10}	2.3×10^{-9}		2.8×10^{-9}		1.4×10^{-9}	
T_{FL11}		1.8×10^{-9}		3.4×10^{-9}		1.5×10^{-9}
T_{FL12}		1.0×10^{-7}				2.1×10^{-7}
T_{FL13}		2.6×10^{-8}				7.8×10^{-8}
T_{FL14}	1.6×10^{-8}				2.0×10^{-8}	
T_{FL15}	4.4×10^{-8}				2.5×10^{-8}	
T_{FL16}	1.1×10^{-6}		8.1×10^{-7}		6.6×10^{-7}	
T_{FL17}	2.4×10^{-7}		8.8×10^{-7}		2.8×10^{-7}	
TOTALS	1.6×10^{-5}	8.2×10^{-7}	2.2×10^{-5}	3.4×10^{-9}	1.7×10^{-5}	5.5×10^{-6}

Table 2.2.1 LER Data for BWR Standby Pumps for the Period of January 1972 Through April 1978

Standby Pumps	Demands	Standby Hours	Leakage Rupture	Does Not Start	Loss of Function	Does Not Continue To Run
Motor Driven	13,644	6,777,627	6	5	4	6
Turbine Driven	1,820	868,033	-	1	6	5

Table 2.2.2 Frequency of Online Major Maintenance System in the Reactor Building

System	Frequency (Per Year) SNSP-PRA	Initiator Event Tree
Core Spray (Motor Driven)	0.042	TFL3
LPCI (Motor Driven)	0.084	TFL4
HPCI (Turbine Driven)	0.079	TFL2
RCIC (Turbine Driven)	0.079	TFL1
Service Water (RHR or RBCLCW HX) (Motor Driven)	0.042	TFL5

Table 2.2.3 Summary of Failure Rates for Major Components Involving External Leak and External Rupture

Parameter Rate	Total Failure Rate/Hr (Mean)	Reference	Rupture* Failure Rate/Hr
Pipe Failure Section (100')	8.5E-10	WASH-1400	4.3E-11
External Failure of a Valve	2.7E-8	WASH-1400	1.3E-9
External Failure of a Pump	3.0E-9	WASH-1400	1.5E-10

*Based upon the operating experience to date, given that a failure occurs, the ratio of external leaks to complete failures appears to be in the range of 20 to 1. This is substantiated by the specific data review cited in the text for values (18 to 1) and data published by Bush[5] on pipes (4 to 1 up to 30 to 1). Because the internal flood evaluation is based upon initiators with substantial flooding rates, i.e., short operator response times, only the catastrophic or large external rupture failures are treated in this evaluation.

Table 2.2.4 Conditional Probability of Pipe Break Size

Break Size	Characterization	Flow Rate	Conditional Probability
Maximum	Guillotine Break	100%	0.05
Large	Substantial Rupture	50%	0.10
Small*	Localized Rupture in Ductile Material	13%	0.85

*Remainder of the conditional probability was allocated to small breaks.

Table 2.2.5 Initiating Event Frequency Estimates Involving Component Leak/Ruptures

INITIATOR	SOURCE	VALVES				PIPING LENGTH (FT)/ SECT/DIA (IN)	ESTIMATED FREQUENCY/ YR
		MOV	MAN	CHK	PUMPS		
HPCI Discharge T_{FL6}	CST/SUPP	2	0	1	0	76/1/14	3.5E-5
CS Discharge T_{FL7}	SUPP	4	0	2	0	128/2/12	6.9E-5
LPCI Discharge T_{FL8}	SUPP	14	4	4	0	240/6/16	2.5E-4
Service Water T_{FL9}	Service Water	4	4	4	0	715/8/10-20	1.4E-4
WFPS T_{FL10}	WFPS	1				157/2/6-8	1.1E-5
RCIC** Suction T_{FL11}	CST	1	1	1	1	70/1/6	3.5E-5
HPCI** Suction T_{FL12}, T_{FL13}	CST**	1	1	1	1	87/1/16	3.5E-5
CS** Suction T_{FL14}, T_{FL15}	CST*	2	2		2	120/2/12	4.9E-5
LPCI** Suction T_{FL16}, T_{FL17}	SUPP	4			4	120/2/20	5.2E-5

*CST is assumed to be the source.
**Suction failures are also classified by flow rate.

Table 2.2.6 Calculated Frequencies for Initiating Events Resulting from System Ruptures (SNPS-PRA)

Initiator	Frequency (Per RX Yr)
Pressurized Piping	
HPCI Discharge Break, TFL6	$3.5x10^{-5}$
CS Discharge Break, TFL7	$6.9x10^{-5}$
LPCI Discharge Break, TFL8	$2.5x10^{-4}$
SW Discharge Break, TFL9	$1.4x10^{-4}$
WFPS Discharge Break, TFL10	$1.1x10^{-5}$
Non-Pressurized Piping	
RCIC Suction Failure, TF11 (max)	$1.75x10^{-6}$*
HPCI Suction Failure, TF12 (max)	$1.75x10^{-6}$*
HPCI Suction Failure, TF13 (large)	$3.5x10^{-6}$*
CS Suction Failure, TF14 (max)	$2.5x10^{-6}$*
CS Suction Failure, TF15 (large)	$4.9x10^{-6}$*
LPCI Suction Failure, TF16 (max)	$2.6x10^{-6}$*
LPCI Suction Failure, TF17 (large)	$5.2x10^{-6}$*

*Modified based upon engineering judgement made on the size of low pressure suction line breaks.

Table 2.3.1

THE PROBABILITY THAT FLOOD REMAINS UNISOLATED FOR X MINUTES
AFTER AUTOMATIC PLANT ACTION: E.G., TURBINE TRIP OR MSIV CLOSURE

X	P(for multiple event)	P(for single event)
1	1	1.0
10	1st + 2nd = 0.54	0.1
20	0.11	0.01
30	0.011	1.1E-3
60	0.0011	2.0E-4
1500	1.1E-4	1.1E-4

3.0 BNL ACCIDENT REVIEW AND SEQUENCE QUANTIFICATION

This section discusses the quantification and review of the internal flooding accident sequences in the SNPS-PRA due to system maintenance and pipe ruptures. The section is organized as follows. Subsection 3.1 presents a summary of the approach used by BNL to calculate the initiator frequencies. Subsection 3.2 discusses BNL quantitative review of the initiator event trees, and Subsection 3.3 presents the functional event tree analysis and evaluation.

3.1 Flood Precursor Frequency

This review revised the assessment of the frequency of the flood initiators in two ways. First the experiential data for the estimation of the various failure rates were revised to include recent events. Second, the models for calculating the frequency of floods (or probability per year of reactor operation) have been improved by removing unnecessary conservatisms. As it was already discussed in Section 2.2, two types of initiators were considered: a) maintenance-induced initiators; and b) rupture-induced initiators. The revised frequencies for these types of initiators are presented in the following two subsections.

3.1.1 Maintenance-Induced Flood Initiators

A flood can be initiated during the maintenance of a component of the ECCS or of another system in the Elevation 8 area if the maintenance process requires dismantling of the component and one of the isolation valves opens inadvertently while the component is being maintained.

The components that contribute to these initiators are the pumps and the heat exchangers in the Elevation 8 area. These are standby components that can fail in a time-dependent fashion while on standby. Periodic tests are performed to check their operability and if found failed they are put under repair.

A Markov model that describes the stochastic behavior of these components has been developed and quantified. The important characteristics of this model are as follows:

i) The component can be in six states (see Figure 3.1.1).

ii) In state 1 the component (pump, heat exchanger) is available, that is ready to start operating if asked to do so.

iii) The component while on standby can fail with exponentially distributed times to failure. A failure brings the component into state 2 (see Figure 3.1.1).

iv) The failure remains undetectable until a test is performed or a real challenge is posed to the component. A test that will find the component in state 2 will initiate a repair action. The same will happen following a real demand for the component.

v) There are three repair states. States 3 and 3' in which the component is under repair while the reactor is online, and State 4 where the component is under repair with the reactor shutdown.

vi) Following a test that finds the component failed and before the dismantling of the component, all the appropriate motor operated valves must be closed and their breakers racked out from the corresponding MCCs. There is, however, a chance that the operator will not remove the breakers from the MCCs leaving then the MOVs able to open following a signal to do so. If the probability of such an error is P, then a test brings the component from State 2, to State 3 with probability 1-P (breaker removed) and to State 3' with probability P.

vii) The component remains in States 3 or 3' until the repair is completed and then it returns to State 1, or until the allowable outage time is exhausted and then the component transit to State 4 where the repair continues with the reactor shutdown. When the repair is completed, the reactor is brought back online and the component returns to State 1 (Transition 4 to 1).

Quantification

The solution of the model requires the quantification of the following parameters.

i) The catastrophic failure rate λ. This failure mode implies such failures that require major maintenance (dismantling) of the component. The SNPS-PRA used the data presented in Table 2.2.1 from Ref. 2. BNL has updated this table using additional data included in an updated version of Ref. 2 (Ref.6). The new data are summarized in Table 3.1.1.

Maximum likelihood estimators for the failure rates

$$\lambda=\left(\frac{\text{number of failures}}{\text{total operating time}}\right) \text{ yield}$$

$\lambda=5.7\times10^{-5}$/hr for Turbine Driven Pumps

and

$\lambda=3.3\times10^{-6}$/hr for Motor Driven Pumps

ii) The mean times to repair were assumed 100 hrs and 50 hrs for the turbine driven and the reactor driven pumps, respectively. Thus

$\mu=10^{-2}$/hr for Turbine Driven Pumps

and

$\mu=2\times10^{-2}$/hr for Motor Driven Pumps.

iii) In the BNL revision of the SNPS-PRA, the frequency of transients involving MSIV closure has been assessed at 4.42/yr. Thus, the frequency of transients on an hourly basis is

$\lambda_D=5.0\times10^{-4}$/hr

iv) Tests are performed every 3 months (4 times a year) for both motor-driven and turbine-driven pumps. The allowable outage times are 14 and 7 days for turbine-driven and motor-driven pumps, respectively.

v) The probability of not racking out the breakers of the isolation valves (P) is assessed in the SNPS-PRA as 10^{-2}. The same value is used in these requantifications.

vi) The mean time for inadvertently activating a particular switch in the control room has been assumed equal to 10,000 hrs. This implies a rate of

$$\lambda_0=10^{-4}/hr.$$

Quantification of the Markovian model with the numerical values of the parameters mentioned above yields the probabilities per year for the various maintenance induced floods. The results are tabulated in Table 3.1.2. Additional assumptions are: the Core Spray System consists of two motor driven pumps, the LPCI consists of four motor driven pumps and that RBCLCW heat exchangers are equivalent to motor driven pumps.

3.1.2 Rupture-Induced Flood Initiators

A flood can be initiated if a rupture occurs at any point in the pressure boundary of the various systems in the Elevation 8 area. Such a rupture will involve one of the following three types of components: 1) piping; 2) valve; and 3) pump. The model assumes that catastrophic ruptures occur in the following way. A component fails in such a way that if it is demanded to operate then a catastrophic rupture (large enough to allow the flow rates necessary for the flood sizes of interest to this analysis) will occur. That is, the component transits first in a rupture-vulnerable state and then, when a demand occurs, it ruptures.

A Markov model that decribes this stochastic behavior has been developed and quantified. The model is graphically depicted in Figure 3.1.2. The basic characteristics of the model are as follows:

(i) The system in question (HPCI, RCIC, LPCI, CS, RHR, RBCLCWHX) is in state where it is available to perform its function.

(ii) The system transits to State 2, which is a rupture vulnerable state with failure rate λ_R.

(iii) If a demand occurs while in State 2 a flood is initiated. A demand occurs whenever a transient, a manual shutdown or a test occurs. We distinguish three flood states: State 3, which is a rupture triggered by a transient involving an MSIV closure; State 4, which is a rupture triggered by a turbine-trip transient; and State 5 which is rupture triggered by a manual shutdown or an equipment test.

The solution of this model yields the probabilities that the system will occupy States 3, 4 and 5 denoted by P_S, P_T, P_M, respectively. These probabilities at the end of one-year period provide the frequency of rupture-initiated flood precursors. The expression for these probabilities is

$$P_i(t) = F \frac{\lambda_i \lambda_R}{\lambda - \lambda_R} [(1-e^{-\lambda_R t})/\lambda_R - (1-e^{-\lambda t})/\lambda] \tag{1}$$

where i = S, T

F is the number of tests per year.

λ_i is the rate of arrival of a transient of type i (i=S,T)

λ_R is the rate of catastrophic rutpure failure in the system

and

λ is the rate of arrival of any transient ($\lambda=\lambda_S+\lambda_T+\lambda_M$)

For the manual shutdown the corresponding expression is

$$P_M(t) = F[\frac{\lambda_M \lambda_R}{\lambda - \lambda_R}(1-e^{-\lambda_R t})/\lambda_R - (1-e^{-\lambda t})/\lambda + \frac{\lambda_R}{\lambda - \lambda_R}(e^{-\lambda_R T} - e^{\lambda T})] \tag{2}$$

<u>Quantification</u>

For a given system having piping of length L, n_v valves and n_p pumps the failure rate λ_R is equal to

$$\lambda_R = L\lambda' + n_v \lambda_v + n_p \lambda_p \tag{3}$$

where λ_V, λ_p are the catastrophic rupture failure rates for valves and pump and λ' the same failure rate per unit of piping length.

A search of the LER, has indicated that at least one pipe rupture (welding failure) has occurred in the ECCS piping in the 215 accumulated BWR years (see Ref.8).

This provides a maximum likelihood estimator for the rupture failure rate of ($1/215\text{yr}=5.31\times10^{-7}/\text{hr}$). Assuming, as in the SNPS-PRA, that only one out of every twenty ruptures will create a break large enough to generate floods of the sizes of concern to this analysis, the catastrophic piping rupture rate becomes $\lambda=2.7\times10^{-8}$. This of course is applicable for the total length of safety related piping (denoted by L).

For a particular system with a total of piping length ℓ, then the catastrophic rupture rate for piping becomes

$$\lambda'' = \left(\frac{\ell}{L}\right)\times2.7\times10^{-8}/\text{hr} \tag{4}$$

where ℓ/L denotes the fraction of the total length of the piping that belongs to the particular system.

For the rupture rates of the valves and the pumps, the WASH-1400 values were used (see Table G.4-4 in SNPS-PRA). Using the length of piping, number of valves and pumps provided in Table G.4-5 of the SNPS-PRA, and by virtue of Eqs.1-3. The total failure rate λ_R for the various systems along with the probabilities P_S, P_T and P_M were calculated. The results are tabulated in Table 3.1.3.

A total of 13.51 transients per year were assumed (4.42 MSIV closures, 4.89 turbine trips and 4.2 manual shutdowns).

The splitting between maximum and large floods for initiators TFL12-TFL13, TFL14-TFL15, TFL16-TFL17 was done as in the SNPS-PRA, that is, 1 to 2. The additional factor of 20 used in the SNPS-PRA to account for non-pressurized piping is not assumed in the BNL quantification.

3.2 BNL Quantitative Review of the Initiator Event Tree

The quantitative review of the initiator event trees is discussed in the following subsections.

3.2.1 Review of Flooding Alarm Related Procedures

The RB water level is detected by two RB water level monitors installed on the RB floor. The flood alarms are activated by the monitors when the water level is more than 0.5 in. above the floor. The sump alarms will be activated when water level reaches the sump alarm setpoints installed at a level right below the level that activates the RB flood alarms. Sump alarm sensors are installed at various locations in the RB.

The immediate operator action specified in the Alarm Response Procedure (ARP5671) is to initiate the Suppression Pool Leakage Return System. The required subsequent actions are:

1. Monitor RB water level to determine approximate leak rate. Use sump alarms to supplement the information obtained from the above instruments to ascertain the approximate location of the leak.
2. Monitor parameters (such as line pressure and flow rate) of the safety systems as a leak would affect the system parameters. Isolate the source of leakage per procedure listed below in Step 3.
3. If required and plant condition permit, dispatch an operator to the RB floor to visually locate the source of leakage. Isolate using the appropriate system procedure listed below.

System

HPCI, Procedure No.SP23.202.01

Leakage indication: . Abnormal suction or discharge piping pressure.
. Excessive HPCI Loop Level Pump Flow or low discharge pressure.

. Reactor building sump high water levels in vicinity of leak.

. Reactor building flooding alarm.

Leakage isolation: . If in standby, isolate the HPCI system by securing the HPCI Loop Level Pump and then closing CST Suction Valve (MOV-031).

. If the system is operating, secure per shutdown procedure and then isolate as described above.

RCIC, Procedure No.SP23.119.01

Leakage indication: . Abnormal suction or discharge piping pressure.

. Excessive HPCI Loop Level Pump.

. Reactor building sump high water levels.

. Reactor building flooding alarm.

Leakage isolation: . If in standby, isolate the RCIC system by securing the RCIC Loop Level Pump and then closing CST Suction Valve (MOV-031).

. If the system is operating, secure per shutdown procedure and then isolate as described above.

RHR, Procedure No.SP23.121.01

Leakage indication: . Heat exchanger service water side temperature inconsistencies.

. Abnormal RHR system flow for mode of operation.

. Abnormal RHR system pressures for mode of operation.

. Reactor water level inconsistencies for mode of operation.

. Sump high level alarms.

. Reactor building flooding alarm.

Leakage isolation: . Isolate the leakage by shutting down the affected loop in accordance with the appropriate procedure for the mode in which it was operating and then systematically shutting valves to isolate areas of the system found above to be possible sources of leakage.

. The above isolation procedure may require intermittent operation of the leakage return system to observe the effects on water buildup.

. When the leakage has been isolated return the unaffected portions (as required) to service.

BNL has found that SNPS alarm response procedures specify general guidelines for monitoring system parameters for determining the leakage location and for initiating the leakage isolation. However, the procedures fail to include specific requirements for operators to systematically check the operation parameters of relevant systems. Since there are many system parameter indicators in the control room, the operators may possibly fail to observe the indication of an abnormal system parameter.

When the abnormal condition is severe enough to actuate the alarm of a particular system parameter, the corresponding Alarm Response Procedure will then be followed by operators. However, BNL has reviewed the relevant Alarm Response Procedures for abnormal system parameters, and found that these procedures do not contain steps that should be followed under RB flood conditions. These procedures provide guidelines for conditions other than RB flood, such as water source abnormal or isolation valves abnormal, etc. The operator responses to the flood could be delayed or confused when these Alarm Response Procedures are followed.

3.2.2 Requantification

The revised initiator frequencies are applied for evaluating the sequence frequencies of the initiator event tree. In addition to the critical flood depth of 3'-10" used by SNPS, BNL also evaluated the sequence frequencies corresponding to flood depth of 1'-10" and 1'-3". This is because, as indicated in Table 3.2.1, flood heights of 1'-10" and 1'-3" will disable several vital systems such as HPCI and RCIC. The times for the flood to reach 3'-10", 1'-10", and 1'-3" depth were calculated based on the leakage flow rates determined in SNPS PRA. The calculated times are shown in Table 3.2.2.

The HEP values used by SNPS are identical to the nominal HEP values provided in the Probabilistic Risk Analysis Procedure Guide[7] (see Figure 3.2.1 and Table 3.2.3). BNL feels that the HEP could be higher than the nominal HEP values because the flooding alarm related procedures fail to provide specific guidelines to identify and to isolate the flood source (see Section 3.2.1).

The HEPs under the multiple alarm and the single alarm conditions are listed in Tables 3.2.4 and 3.2.5.

3.3 BNL Review of Functional Event Tree

This section is divided into three subsections. Section 3.3.1 provides a qualitative review of the Shoreham Internal Flood event tree analysis and Section 3.3.2 presents the BNL revised time phased event trees. Section 3.3.3 describes the results obtained from the quantification of the BNL event trees.

3.3.1 Qualitative Review

In general, BNL is of the opinion that the methodology used in the Shoreham Internal Flood Analysis is consistent with that of the state-of-the-art and the approach is reasonable. The analysis for the internal flood postulated much severe scenarios than those of the Shoreham FSAR.

The Shoreham Internal Flood functional event tree analysis is based predominantly on the event trees developed for the internal event initiators, namely, turbine trip, MSIV closure and manual shutdown. These internal flood functional event trees only model flood scenarios where the flood water height at Elevation 8 exceeds 3'-10". While it appears that the Shoreham functional event trees do provide a representative modeling of the plant response, it is not well substantiated that floods that are arrested before reaching 3'-10" will result in negligible core vulnerable frequency.

3.3.2 BNL Time Phase Event Tree

The determination of the time periods which are critical to the consideration of the progression of the flood is based on the vital equipment location list (Table 3.3.1). Three heights were selected for the BNL analysis: at the 1'-3" level, at the 1'-10" level, and at the 3'-10" level. If the flood is terminated prior to reaching the 1'-3" level, no impact is assumed for any equipment and the plant will be shutdown, this is Phase 1. However, if the flood water exceeds the 1'-3" level but is terminated before the 1'-10" level, this is Phase II. Phase III entails the failures of both HPCI and RCIC system as well as the loss of power to the MG set recirculation pump fluid coupler before arresting the flood below the 3'-10" level. Any flood level which exceeds the 3'-10" level, it is treated in Phase IV.

The event trees of these four phases are presented in Figures 3.3.1 through 3.3.4. Given that the flood is terminated in Phase I, BNL assumed that the reactor has a high probability (0.9) that it will be manually shutdown. Ten percent of the time, it may result in a MSIV closure event. These two branches of the Phase I event trees are transferred to the respective internal event tree, Figure 3.3.1.

Figure 3.3.2 depicts the Phase II functional event tree which considers the various accident mitigation systems. Moreover, owing to the fact that a number of the 480V pumps will be flooded, the possibility of a breaker failure to isolate the fault is also evaluated. It is assumed that the breaker failure to open probability is $1x10^{-3}$ and there are a total of five pumps in Division 1 and two pumps in Division II that will be short circuited. A probability of 0.5 is also assumed that failure of a load center in a division would lead to failure of other equipment connected to that division. In the event of a MSIV closure, the feedwater system is considered to be unavailable. The probability that the reactor will be manually shutdown is also assumed to be 0.9 for the maintenance induced flood events.

Figure 3.3.3 illustrates the functional event tree used to describe the Phase III events. The major difference between this event tree and the Phase

II tree is the high pressure systems. In the Phase III events, both the RCIC and the HPCI systems are unavailable due to the failure of respective instrumentation. The probability that the reactor will be manually shutdown is assumed to be 0.5 for the maintenance induced flood events.

The Phase IV event tree is presented in Figure 3.3.4. This tree is drastically different from the other ones in that it only considers the feedwater system, the depressurization function and the PCS. All the other systems are disabled due to flooding. The likelihood that the reactor will be manually shutdown is the same as in Phase III for maintenance-induced floods.

3.3.3 Quantitative Analysis

Based on the development of the revised flood initiator frequency, the BNL time-phased event tree and the modified human response to arrest flood, quantitative results are obtained. In the BNL analysis, there are 17 different flood precursors. Similar to the Shoreham classification, the first five precursors are online maintenance related; the remaining twelve of them are rupture related. A detailed discussion on the BNL flood precursors is given in Section 3.1.

Owing to the ways that these flood precursors are calculated, the initiator event trees have been modified to include only three functions: the flood alarm annunication, I; operator action to isolate flood, A; and reactor status. The entry condition to the different time phase event trees is determined by the A function (see Section 3.2 for details).

Each of the 17 flood precursors were evaluated with the initiator event tree and the four time phase event trees. The unavailability values for the various event trees are the same as those used in the Shoreham analysis except as noted in the last section.

When the time phase event trees were quantified for the 17 flood precursors, the results are the conditional frequency of core vulnerable given the particular flood precursor. These frequencies are summarized in Table

3.3.2. The seventeen precursors are listed as rows while the four phases are shown as columns. Within each precursor, contributions from manual shutdown, MSIV closure or turbine trip are also shown. For instance, the conditional frequency of core vulnerable with operator arresting the flood prior to 3'-10" but after 1'-10" - Phase III, for TFL1 is 2.0(-5) given the reactor is manually shutdown. However, if instead of a manual shutdown, the plant experiences a MSIV closure, then the conditional frequency is 8.5(-4).

As expected, the conditional frequency consistently increases as the flood progresses to higher elevations. In other words, the conditional frequency of Phase IV is always larger than any of the other phases. Another noteworthy observation is the unusually large conditional frequency of core vulnerable for the LPCI system induced flood, i.e., TFL4 and TFL8. The TFL9 and TFL5 values are also large since they disabled the LPCI systems as well.

The core vulnerable frequency given the BNL revised flood precursors, initiator event trees and time phase event trees is shown in Table 3.3.3. In this table, the 17 precursors are depicted on the left with the 4 phases depicted as columns. Each precursor also identifies the contributions from the various plant states. Core vulnerable frequency contributions from Phase I and II are very small, in the order of 10^{-9}. Contributions from Phase III are not insignificant but not substantial, approximately 10^{-6}. Seventy percent of the total core vulnerable frequency (70% of 2.0(-5)) is attributable to LPCI system maintenance or rupture induced flood. The maintenance contribution to flood is about 37% while the balance is due to rupture.

It appears also that failure to properly model the fault propagation of the short circuits through the breakers does not have a significant effect on core vulnerable frequency.

3.4 Uncertainty Estimates

This section presents a limited uncertainty assessment on the BNL quantitative analysis for the core vulnerable frequency due to reactor building flooding.

A rigorous propagation of the uncertainties is outside the scope of the present review. The BNL approach for the uncertainty evaluation consisted of the following general steps.

1. The uncertainties in the human errors as well as the split ratio between the manual shutdown and the MSIV closure event were quantified by fitting lognormal distributions to evaluate uncertainty measures (mean and variance). An error factor of 10 was applied to human errors and the split ratio.

2. Human errors of the following operator actions were included for the uncertainty evaluation:

   . Operator maintains isolation valves in closed position during the online maintenance (Event E, see Section 2.3).

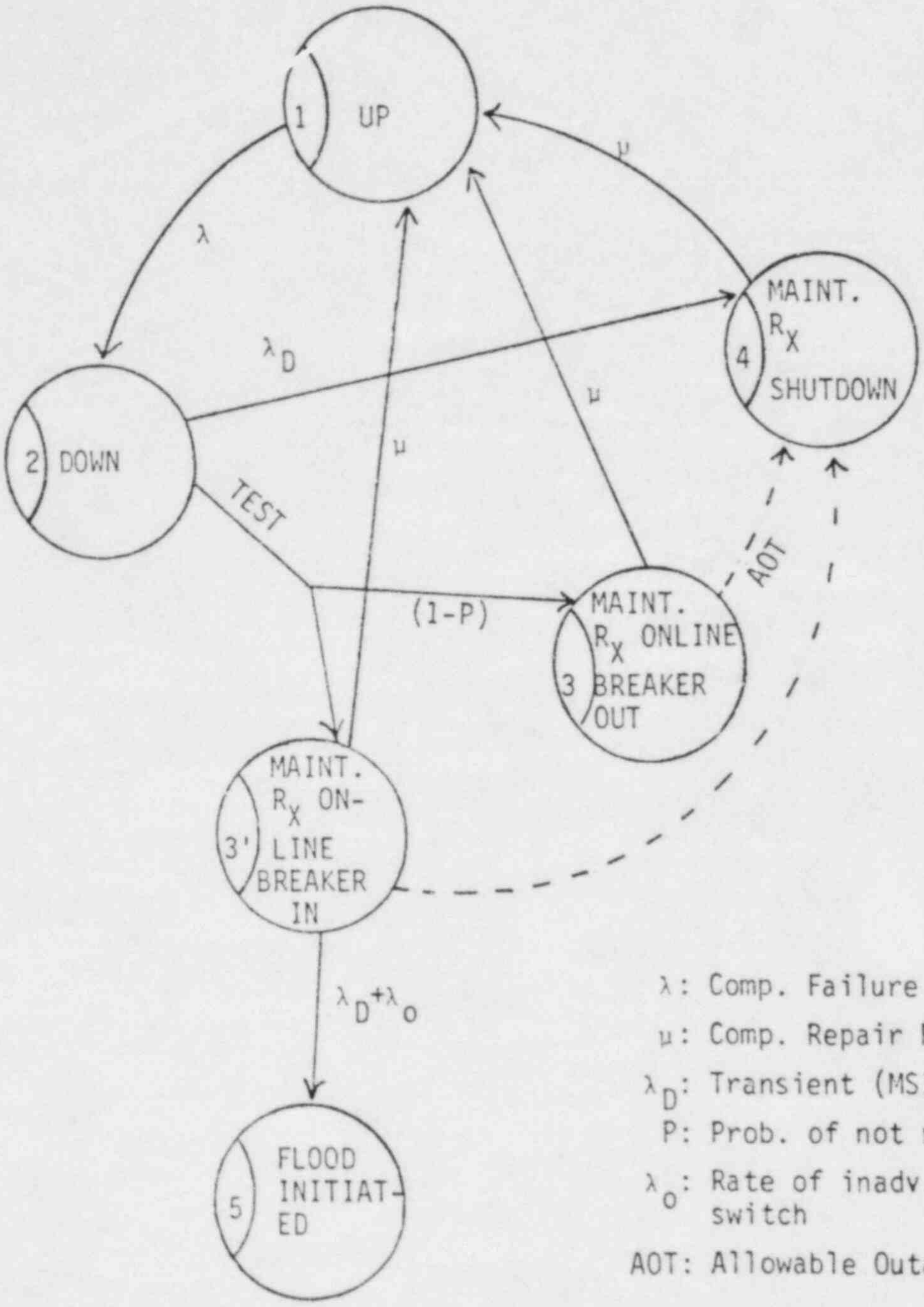
   . Operator diagnoses and responds to isolate the flood (Event A, see Section 2.3).

   . Operator depressurizes the Reactor Pressure Vessel (Event X, Figures 3.3.2-3.3.4).

3. The uncertainties in the core vulnerable frequency were evaluated using the major accident sequences and the distributions assessed in Step 1.

The SAMPLE code was used for the estimaton of uncertainties. The mean, median, 5% and 95% probability intervals for the core vulnerable frequency are shown as follows.

Mean	=	1.91E-5
Median	=	1.90E-6
5% Confidence	=	2.19E-7
95% Confidence	=	7.51E-5



λ: Comp. Failure Rate

μ: Comp. Repair Rate

λ_D: Transient (MSIV clos.) Rate

P: Prob. of not racking out Breaker

λ_o: Rate of inadv. operation of switch

AOT: Allowable Outage Time

Figure 3.1.1 State Transition Diagram for Component-Maintenance Induced Floods.

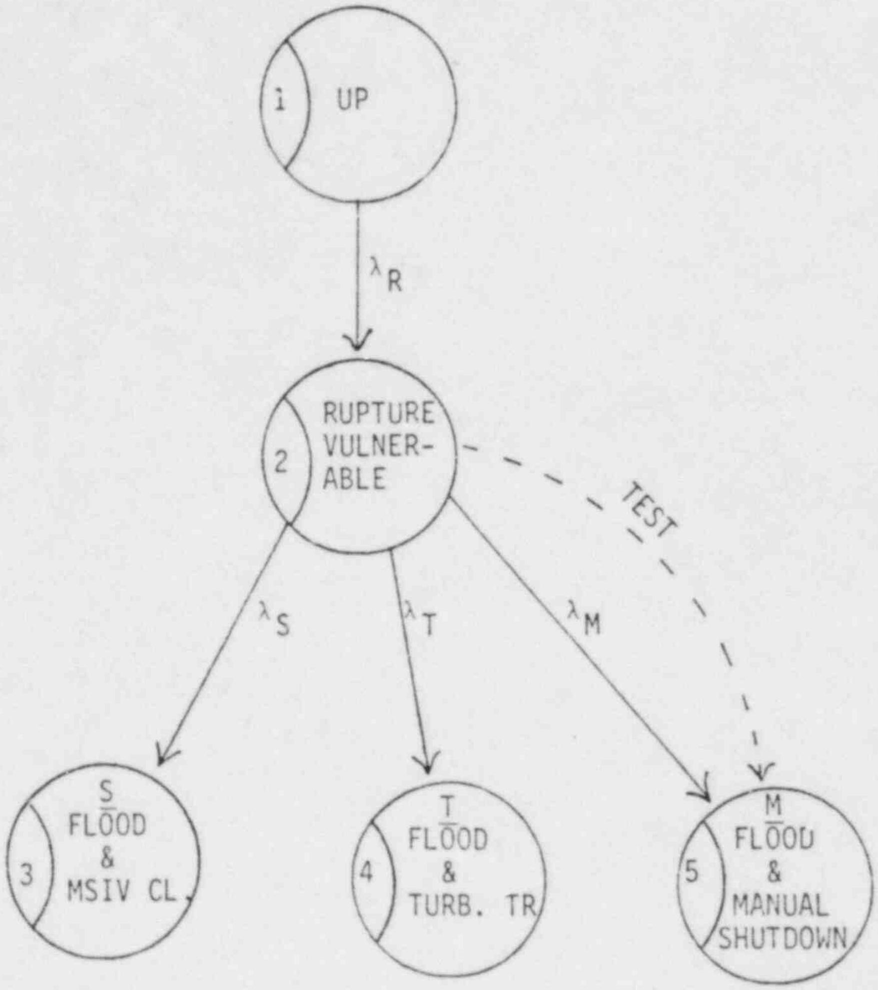


Figure 3.1.2 State Transition Diagram for Rupture-Induced Floods.

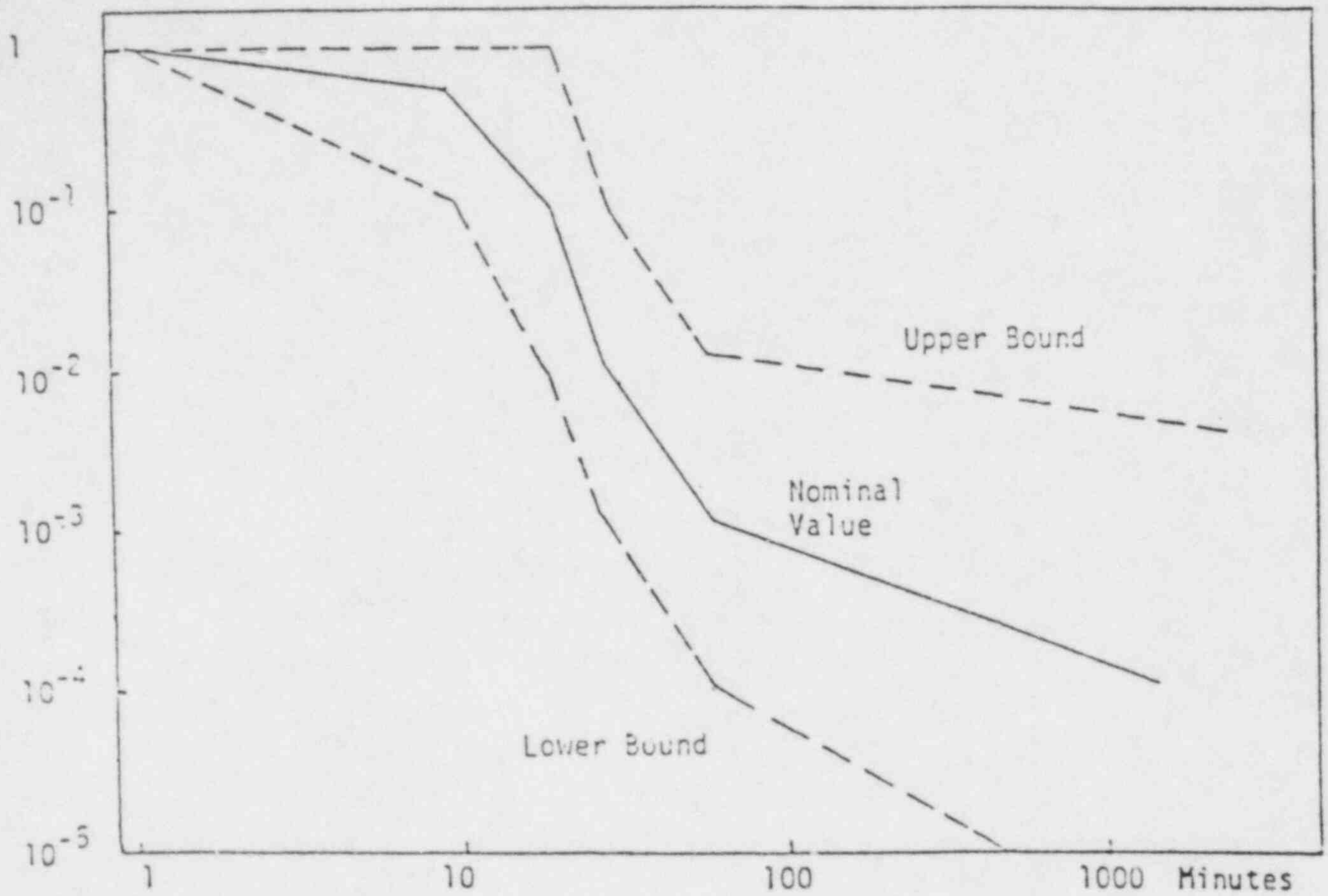


Figure 3.2.1 Problem-solving human error probability vs time - screening values.

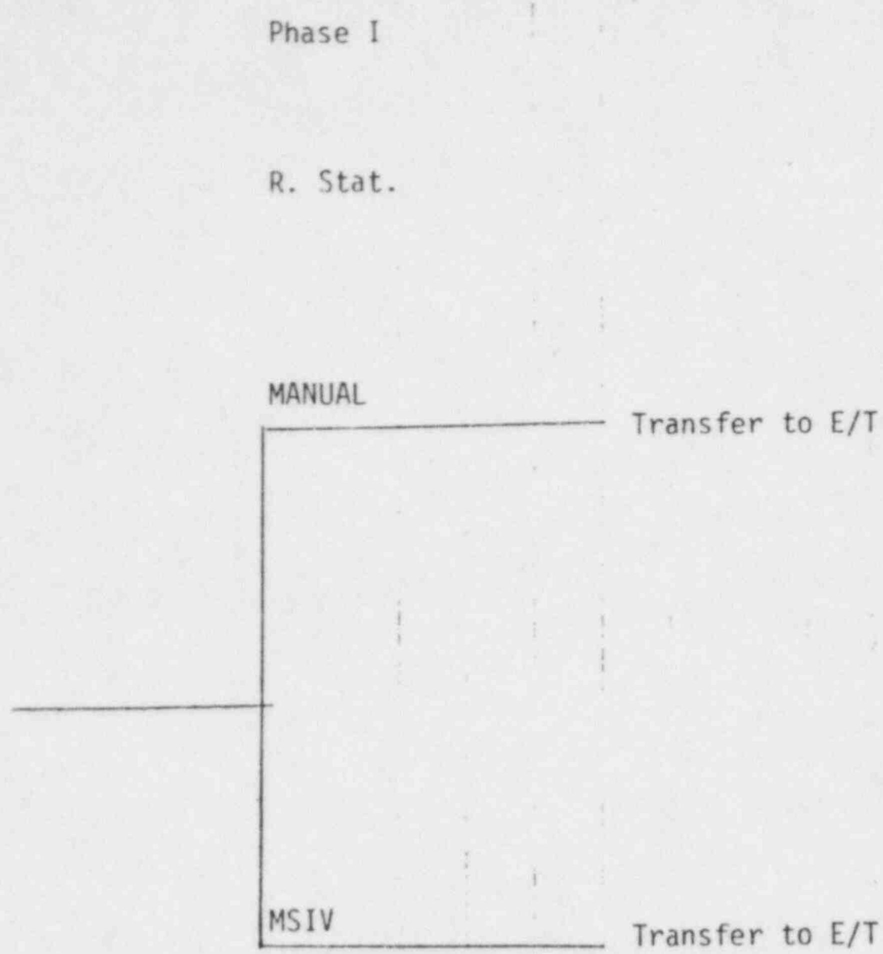


Figure 3.3.1 Phase I of Internal Flood Functional Event Tree

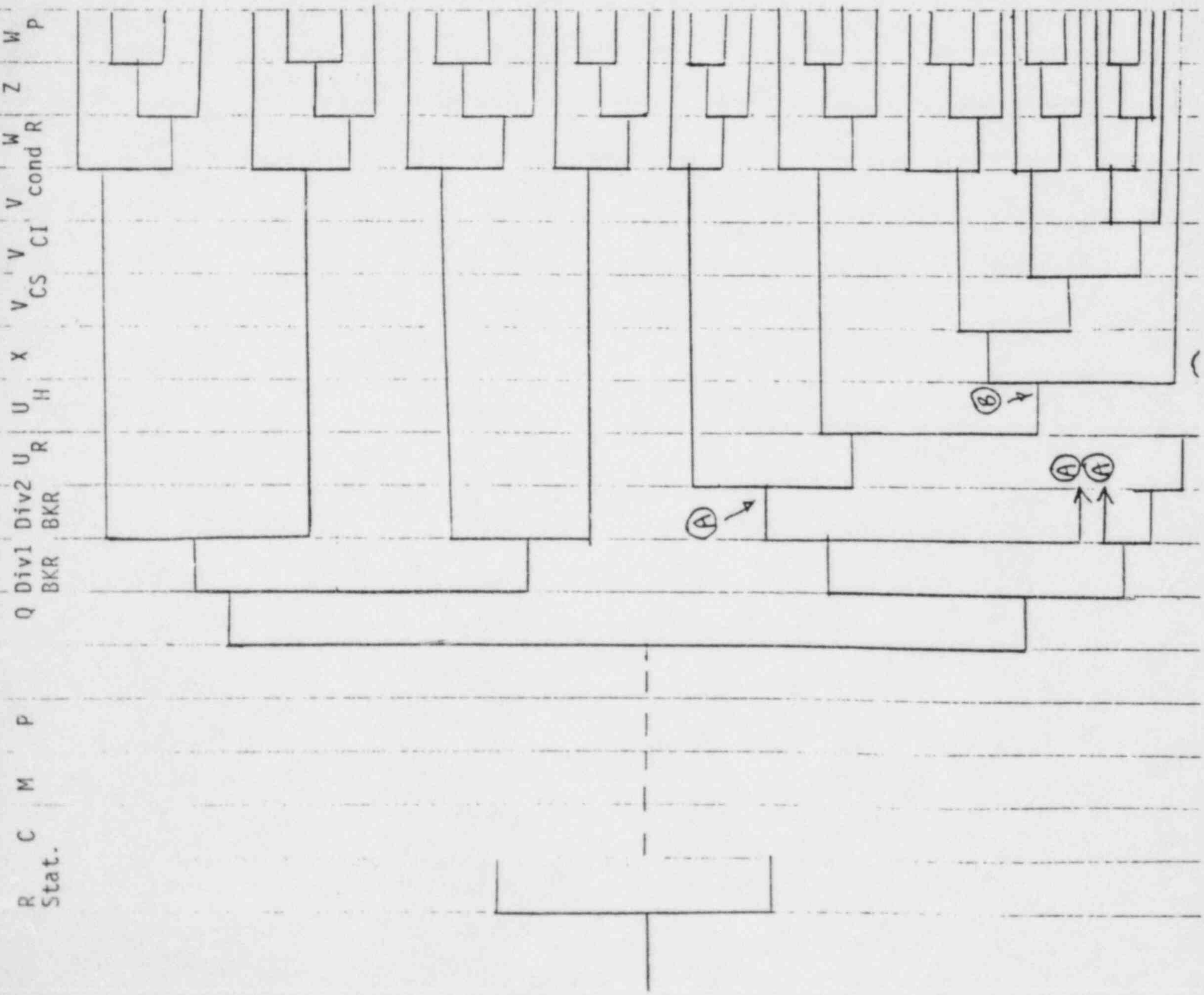
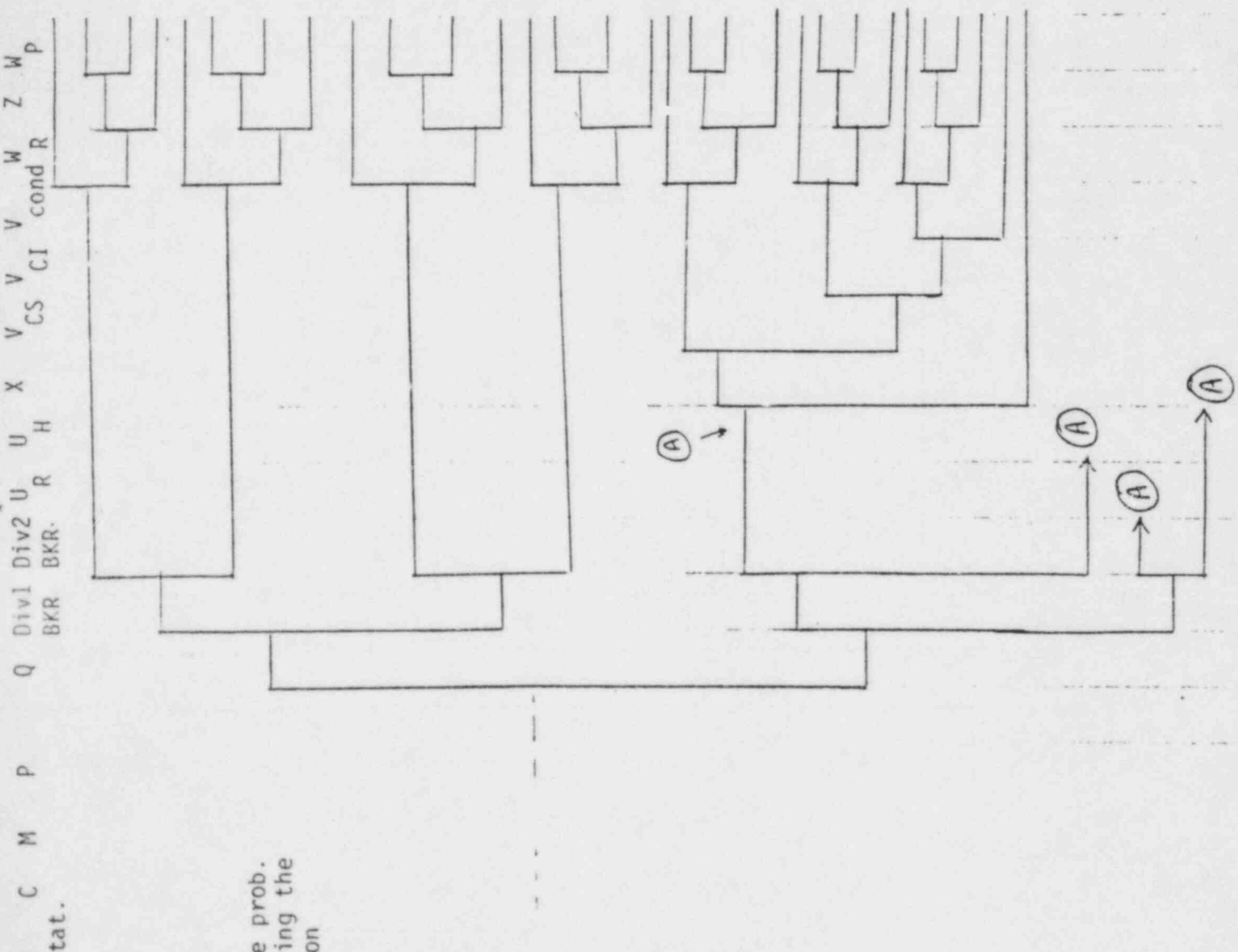


Figure 3.3.2 Phase II of Internal Flood Functional Event Tree



*include prob. of losing the division

Figure 3.3.3 Phase III of Internal Flood Functional Event Tree

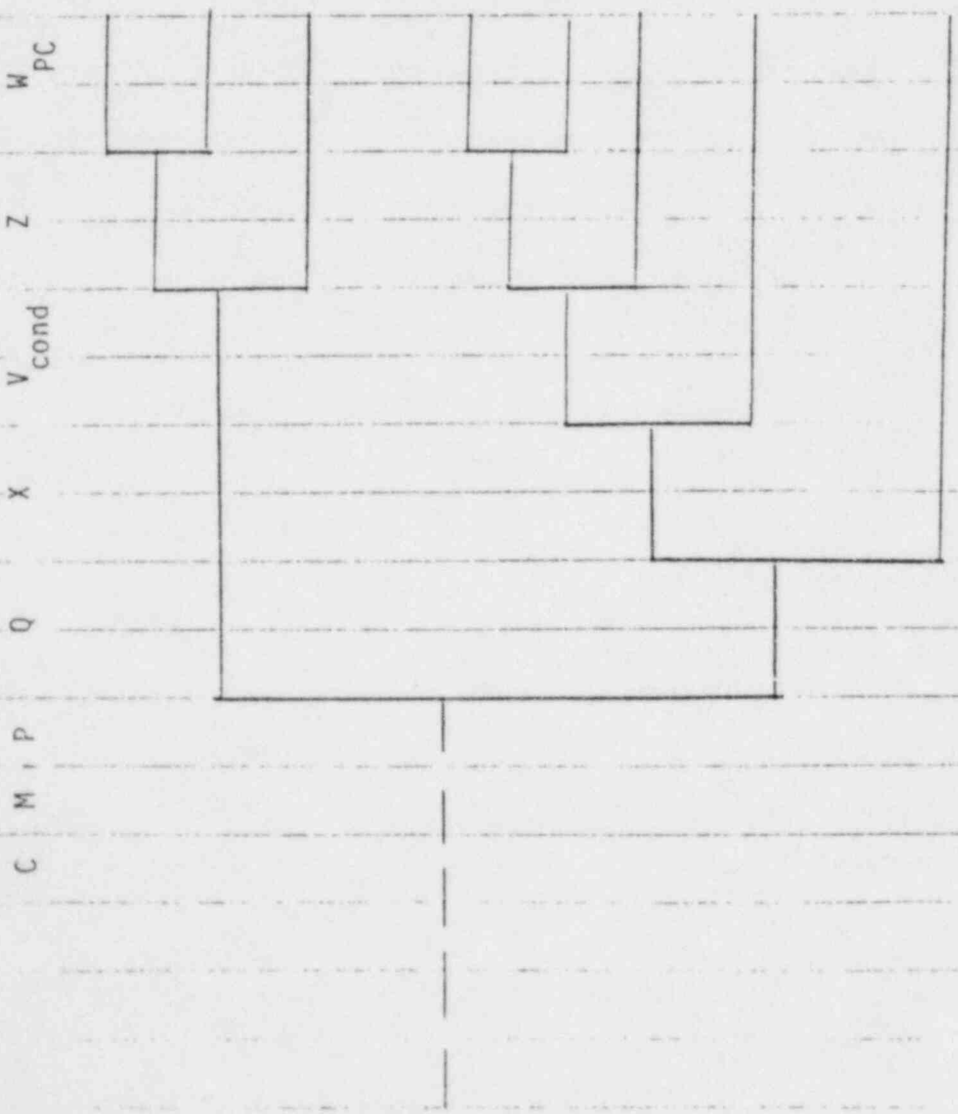


Figure 3.3.4 Phase IV of Internal Flood Functional Event Tree

Table 3.1.1 LER Data for BWR Standby Pumps for the Period of January 1972 Through September 1980

Standby Pumps	Demands	Standby Hours	Leakage Rupture	Does Not Start	Loss of Function	Does Not Continue To Run
Motor Driven	20,321	10,453,806	9	8	8	9
Turbine Driven	2,860	1,439,491	-	34	25	23

Table 3.1.2 Frequency of Maintenance - Induced Flood Precursors

System	Initiator Event Trees	Probability per Year
1. RCIC	TFL1 P.D	1.05×10^{-4}
	TFL1 P.E_O	2.10×10^{-5}
	TFL1 P.E_L	2.10×10^{-5}
2. HPCI	TFL2 P.D	1.05×10^{-4}
	TFL2 P.E_O	2.10×10^{-5}
	TFL2 P.E_L	2.10×10^{-5}
3. Core Spray	TFL3 P.D	1.89×10^{-5}
(2 motor driven pumps)	TFL3 P.E_O	1.87×10^{-6}
4. LPCI	TFL4 P.D	3.78×10^{-5}
(4 motor driven)	TFL4 P.E_O	3.74×10^{-6}
5. Service Water	TFL5 P.D	1.89×10^{-5}
(RHR or RB(LW HX)	TFL4 P.E_O	1.88×10^{-6}
2 motor driven pumps		

Table 3.1.3 Flood Precursor Frequency

	Pipe	Valves	Pump	Total λ_R	P_S	P_T	P_M
TFL6	1.2(-9)	6.5(-9)	0	7.7(-9)	1.6(-5)	1.7(-5)	1.5(-5)
TFL7	2.0(-9)	1.3(-8)	0	1.5(-8)	3.1(-5)	3.4(-5)	2.9(-5)
TFL8	3.7(-9)	2.9(-8)	0	3.2(-8)	6.5(-5)	7.3(-5)	6.2(-5)
TFL9	1.1(-8)	2.3(-8)	6.0(-10)	1.3(-8)	2.6(-5)	2.9(-5)	2.5(-5)
TFL10	2.4(-9)	1.3(-9)	0	3.7(-9)	7.5(-6)	8.4(-6)	7.2(-6)
TFL11	1.1(-9)	9.1(-9)	1.5(-10)	1.0(-8)	2.1(-5)	2.4(-5)	2.0(-5)
TFL12	1.4(-9)	3.9(-9)	1.5(-10)	5.5(-9)	3.7(-6)	4.0(-6)	3.6(-6)
TFL13	-	-	-	-	7.3(-6)	8.0(-6)	7.1(-6)
TFL14	1.9(-9)	5.2(-9)	3.0(-10)	7.4(-9)	5.0(-6)	5.6(-6)	4.8(-6)
TFL15	-	-	-	-	1.0(-5)	1.1(-5)	9.6(-6)
TFL16	1.9(-9)	5.2(-9)	6.0(-10)	7.7(-9)	5.2(-6)	5.8(-6)	5.0(-6)
TFL17	-	-	-	-	1.0(-5)	1.2(-5)	1.0(-5)

Table 3.2.1

MAJOR ELEVATION 8 EQUIPMENT LIST

EQUIP TYPE	EQUIPMENT DESCRIPTION	PART NO.	POSTULATED DISABLED HEIGHT*
PUMPS			
	Floor Drain Sump Pumps	1G11*P-035A-D 1G11*P-036A-F	1'-0"
	Dry Floor Drain Tank Pumps	1G11*P-151A,B	1'-0"
	Radwaste Equip. Drain Sump & Pump to Porous Sump	1G11*P-224A,B	1'-1"
	** HPCI Pump	1E41*P-016	-----
	HPCI Vacuum Pump	1E41*P-075	1'-0"
	HPCI Con. Pump	1E51*P-076	1'-0"
	** RCIC Pump	1E51*P-015	-----
	RCIC Vacuum Pump	1E51*P-076	1'-0"
	RCIC Con. Pump	1E51*P-077	1'-0"
	** RHR Pump Motors	1E11*P-014A-D	5'-4"
	** Leakage Return Pump	G11-*P-270	3'-9"
	** Core Spray Loop Level Pumps	1E21*P-049A,B	1'-3"
	Drywell Equip. Drain Tank Pumps	1G11*P-0332A,B	1'-2"
	RCIC Loop Level Pump	1E51*P-051	1'-4"
	** HPCI Loop Level Pump	1E41*P-050	2'-3"
TURBINES			
	** HPCI Turbine	1E41*-TU-002	6'-0"
	** RCIC Turbine	1E41*-TU-005	4'-0"

Table 3.2.1 (Continued)

MAJOR ELEVATION 8 EQUIPMENT LIST

EQUIP. TYPE	EQUIPMENT DESCRIPTION	PART NO.	POSTULATED DISABLED HEIGHT*
MOTOR CONTROL CENTERS			
	Sump Pumps and Cooling Water Pumps to Recirc. Pump MG-Set Fluid Coupler	1R24-11D1 1R24-12D1	1'-6" 1'-6"
TANKS			
	Floor Drain Sump Tank	1G11*TK-050A,B 1G11*TK-056A-C	----- -----
	Drywell Floor Drain Receiver	1G11*TK-057	-----
	Salt Water Drain Tank	1G11*TK-190	-----
	Drywell Equip. Drain Receiver	1G11*TK-049	-----
HEAT EXCHANGER			
	HPCI Barometric Con. Vacuum Tank	1E41*E-036	-----
	RCIC Barometric Con. Tank	1E51*E-038	-----
	RHR Heat Exchanger	1E114*E-034A,B	-----
	RBCLCW Heat Exchangers	1P42*-011A,B	-----
	Drywell Equip. Drain Cooler	1G11*E-094	-----

Table 3.2.1 (Continued)
MAJOR ELEVATION 8 EQUIPMENT LIST

EQUIP. TYPE	EQUIPMENT DESCRIPTION	PART NO.	POSTULATED DISABLED HEIGHT+
ELEC. PANELS			
	** RCIC Instr. Rack	1H21*PNL-017	2'-0"
	** RCIC Instr. Rack	1H21*PNL-037	2'-0"
	** Core Spray Rack	1H21*PNL-01	3'-10"
	** Core Spray Rack	1H21*PNL-019	3'-10"
ELEC. PANELS			
	** RHR Inst. Rack A	1H21*PNL-018	3'-10"
	** RHR Inst. Rack B	1H21*PNL-021	3'-10"
	** HPCI Inst. Rack A	1H21*PNL-036	1'-10"
	** HPCI Inst. Rack B	1H21*PNL-14	1'-10"

** Equipment required for operation of the identified system.
+ Heights are taken from a physical survey measurement from the bottom of the component to floor level.
---- Non-electrical component

Table 3.2.2 Times to Flood Depth of 3'-10", 1'-10", and 1'-3" in Reactor Building

System	Water Source	Leakage Location	Time (min.) to Flood Depth of 3'-10"	1'-10"	1'-3"
HPCI	S.P.	pump suction (max.)	17	7.9	5.4
	S.P.	pump suction (large	34	15.8	10.8
	CST	pump suction (max.)	13	6.4	4.4
	CST	pump suction (large)	27	12.8	8.7
	---	pump discharge	37	17.5	11.9
RCIC	S.P.	pump suction (max.)	110.0	50.8	34.6
	S.P.	pump suction (large)	220.0	101.6	69.3
	CST	pump suction (max.)	76.0	36.3	24.8
	CST	pump suction (large)	152.0	72.6	49.5
LPCI	S.P.	pump suction (max.)	9.4	4.5	3.1
	S.P.	pump suction (large)	19.0	9.0	6.1
	---	pump discharge	15	7.3	5.0
CS	S.P.	pump suction (max.)	12	5.9	4.0
	S.P.	pump suction (large)	24	11.8	8.1
	CST	pump suction (max.)	13	6.4	4.4
	CST	pump suction (large)	27	12.8	8.7
	---	pump discharge	23	11.1	7.6
SW	SW	RHR heat exchanger	20	9.5	6.5
WFPS	WFPS	rupture of 8" pipe	40	19.1	13.0

Note:
1. Large flow rates is 1/2 of maximum flow rates.
2. Flood times were calulated based on a 41,600 gallons per foot depth in the reactor building.
3. S.P. = Suppression Pool
   CST = Condensate Storage Tank
   SW = Service Water System
   WFPS = Water Fire Protection System Tanks

Table 3.2.3 Human Error Probability: Screening Values

Problem-solving

Time	Nominal Value	Error Factor
<1 min.	1	---
10 min.	5E-1	5
20 min.	1E-1	10
30 min.	1E-2	10
60 min.	1E-3	10
1500 min.	1E-4	30

Procedural Errors

Nominal Value	Error Factor
1E-3 (With Recovery)	3
1E-2 (Without Recovery)	3

Table 3.2.4 HEP (Event A) Single Alarm Condition Manual Shutdown (NUREG/CR-1278)

	1'-3"	1'-10"	3'-10"
TFL1	10^{-3}	10^{-3}	2.0×10^{-4}
TFL2	1	1	0.1
TFL3	1	1	0.1
TFL4	1	1	1
TFL5	1	1	10^{-2}
TFL6	0.1	0.1	10^{-3}
TFL7	1	0.1	10^{-2}
TFL8	1	1	0.1
TFL9	1	1	10^{-2}
TFL10	0.1	0.1	10^{-3}
TFL11	10^{-3}	10^{-3}	2×10^{-4}
TFL12	1	1	0.1
TFL13	0.1	0.1	10^{-3}
TFL14	1	1	0.1
TFL15	1	0.1	10^{-2}
TFL16	1	1	1
TFL17	1	1	0.1

Table 3.2.5 HEP (Event A), Multiple Alarm Condition (Nominal Value, PRA Procedures Guide)

	1'-3"	1'-10"	3'-10"
TFL1	10^{-2}	10^{-2}	10^{-3}
TFL2	1	1	0.5
TFL3	1	1	0.5
TFL4	1	1	1
TFL5	1	1	0.1
TFL6	0.5	0.5	10^{-2}
TFL7	1	0.5	0.1
TFL8	1	1	0.5
TFL9	1	1	0.1
TFL10	0.5	0.5	10^{-2}
TFL11	10^{-2}	10^{-2}	10^{-3}
TFL12	1	1	0.5
TFL13	0.5	0.5	10^{-2}
TFL14	1	1	0.5
TFL15	1	0.5	0.1
TFL16	1	1	1
TFL17	1	1	0.5

Table 3.3.1 Vital Equipment Locations at Elevation 8

1'	HPCI vac. pump cond. pump RCIC vac. pump cond. pump	1'-3"
1'-3"	CS loop level pump	
1'-4"	RCIC loop pump	
1'-6"	recir. pump M-G set	1'-10"
1'-10"	HPCI instrumentation	
2'	RCIC instrumentation	
2'-3"	HPCI loop level pump	
3'-10"	RHR instrumentation CS instrumentation	3'-10"

Table 3.3.2 Conditional Frequency of Core Vulnerable (1 of 2)

		Phase I	Phase II	Phase III	Phase IV
TFL1	Manual	5.8(-7)	2.7(-6)	2.0(-5)	7.3(-3)
	MSIV	3.2(-6)	8.7(-5)	8.5(-4)	1.2(-1)
	TT	7.7(-7)	2.2(-5)	2.1(-4)	3.3(-2)
TFL2	Manual	5.8(-7)	2.2(-6)	2.0(-5)	7.3(-3)
	MSIV	3.2(-6)	6.8(-5)	8.5(-4)	1.2(-1)
TFL3	Manual	5.8(-7)	1.1(-6)	2.2(-5)	7.3(-3)
	MSIV	3.2(-6)	1.1(-5)	9.5(-4)	1.2(-1)
TFL4	Manual	5.8(-7)	3.9(-4)	5.2(-4)	7.3(-3)
	MSIV	3.2(-6)	2.0(-2)	2.6(-2)	1.2(-1)
TFL5	Manual	5.8(-7)	3.9(-4)	5.2(-4)	7.3(-3)
	MSIV	3.2(-6)	2.0(-2)	2.6(-2)	1.2(-1)
TFL6	Manual	5.8(-7)	2.2(-6)	2.0(-5)	7.3(-3)
	MSIV	3.2(-6)	6.8(-5)	8.5(-4)	1.2(-1)
	TT	7.7(-7)	1.6(-5)	2.1(-4)	3.3(-2)
TFL7	Manual	5.8(-7)	1.1(-6)	2.2(-5)	7.3(-3)
	MSIV	3.2(-6)	1.1(-5)	9.5(-4)	1.2(-1)
	TT	7.7(-7)	3.2(-6)	2.3(-4)	3.3(-2)
TFL8	Manual	5.8(-7)	3.9(-4)	5.2(-4)	7.3(-3)
	MSIV	3.2(-6)	2.0(-2)	2.6(-2)	1.2(-1)
	TT	7.7(-7)	4.7(-3)	6.2(-3)	3.3(-2)
TFL9	Manual	5.8(-7)	3.9(-4)	5.2(-4)	7.3(-3)
	MSIV	3.2(-6)	2.0(-2)	2.6(-2)	1.2(-1)
	TT	7.7(-7)	4.7(-3)	6.2(-3)	3.3(-2)
TFL10	Manual	5.8(-7)	1.1(-6)	2.2(-5)	7.3(-3)
	MSIV	3.2(-6)	1.0(-5)	9.5(-4)	1.2(-1)
	TT	7.7(-7)	3.2(-6)	2.3(-4)	3.3(-2)
TFL11	Same as TFL1				
TFL12	Same as TFL6				
TFL13	Same as TFL6				

Table 3.3.2 Conditional Frequency of Core Vulnerable
(2 of 2)

		Phase I	Phase II	Phase III	Phase IV
TFL14	Manual	5.8(-7)	1.1(-6)	2.2(-5)	7.3(-3)
	MSIV	3.2(-6)	1.1(-5)	9.5(-4)	1.2(-1)
	TT	7.7(-7)	3.2(-6)	2.3(-4)	3.3(-2)
TFL15	Same as TFL14				
TFL16	Same as TFL8				
TFL17	Same as TFL8				

Table 3.3.3 Core Vulnerable Frequency
(1 of 2)

		P-1	P-2	P-3	P-4	TOTAL
TFL1	Man.	7.3(-11)	0	1.7(-11)	1.2(-9)	
	MSIV	4.5(-11)	0	8.2(-11)	1.3(-8)	
		1.2(-10)	0	9.9(-11)	1.5(-8)	1.4(-8)
TFL2	Man.	0	0	9.1(-10)	2.1(-7)	
	MSIV	0	0	3.9(-8)	3.4(-6)	
		0	0	4.0(-8)	3.6(-6)	3.7(-6)
TFL3	Man.	0	0	1.2(-10)	3.5(-8)	
	MSIV	0	0	5.2(-9)	5.8(-7)	
		0	0	5.3(-9)	6.1(-7)	6.2(-7)
TFL4	Man.	0	0	0	1.5(-7)	
	MSIV	0	0	0	2.5(-6)	
		0	0	0	2.7(-6)	2.7(-6)
TFL5	Man.	0	0	4.9(-9)	6.9(-9)	
	MSIV	0	0	2.5(-7)	1.1(-7)	
		0	0	2.5(-7)	1.1(-7)	3.7(-7)
TFL6	Man.	*	0	*	1.6(-10)	
	MSIV	*	0	1.4(-8)	5.6(-8)	
		*	0	1.4(-8)	5.6(-8)	7.0(-8)
TFL7	Man.	0	*	*	1.4(-9)	
	MSIV	0	3.9(-10)	2.6(-8)	8.3(-7)	
		0	3.9(-10)	2.6(-8)	8.3(-7)	8.6(-7)
TFL8	Man.	0	0	1.5(-8)	2.3(-8)	
	MSIV	0	0	1.6(-6)	4.3(-6)	
	TT	0	0	2.3(-7)	1.2(-6)	
		0	0	1.8(-6)	5.5(-6)	7.3(-6)
TFL9	Man.	0	0	6.5(-9)	1.2(-9)	
	MSIV	0	0	9.2(-7)	3.4(-7)	
	TT	0	0	1.8(-8)	9.9(-8)	
		0	0	9.4(-7)	4.4(-7)	1.4(-6)

*Less than 1.0(-10).

4.0 SUMMARY

BNL reviewed the internal flood analysis which is a part of the Shoreham PRA and found that assumptions, methodology, and results are reasonable. BNL re-evaluated the flood precursor frequency using recent LER data and a more accurate methodology. This methodology avoids some of the conservatisms in the SNPS-PRA approach. A slight increase in the initiator frequency is calculated because of the revised data.

Similarly, based on the PSA Procedure Guide, the HEP was reviewed and only minimal changes were made to the Shoreham HEP values used in the analysis. As for the functional event trees, a time phase approach was adopted to better model the progression of the flood events.

Results are summarized in Table 4.1. This table can be divided into three parts. Part A provides a comparison between the Shoreham results and those obtained in the BNL review. The BNL value is about 5 times that of the Shoreham frequency, 2.0(-5) vs. 3.9(-6). The contributions from the different plant states are also presented. The major increase in the total core vulnerable frequency in the BNL analysis is attributable to the increase in flood precursor frequencies. Part B compares only the contributions from the BNL Phase IV results with the Shoreham values. It can be inferred that by neglecting the initial three phases, the core vulnerable frequency will be underestimated by 3×10^{-6} or about 18%. Part C shows the contributions of core vulnerable frequency for different plant states due to maintenance and rupture induced floods. In the Shoreham analysis 41% of the core vulnerable frequency is calculated to be caused by maintenance related floods while the BNL analysis shows 37%.

An uncertainty estimation has been carried out assuming lognormal distributions. An error factor of 10 was applied to the operator errors and the split ratio for the manual shutdown and the MSIV closure event following the Reactor Building flooding. The results of the uncertainty assessment for the core vulnerable frequency are as follows.

Mean	=	1.9E-5
Median	=	1.9E-6
5% Confidence	=	2.2E-7
95% Confidence	=	7.5E-5

Table 4.1 Summary of Core Vulnerable Frequency

	Shoreham	BNL
Part A		
Manual	8.5(-8)	4.8(-7)
MSIV	3.0(-6)	1.8(-5)
TT	7.7(-7)	2.0(-6)
Total	3.9(-6)	2.0(-5)

	Shoreham	BNL (only Phase IV
Part B		
Manual	8.5(-8)	4.5(-7)
MSIV	3.0(-6)	1.5(-5)
TT	7.7(-7)	1.7(-6)
Total	3.9(-6)	1.7(-5)

		Shoreham	BNL
Part C			
Manual	Maintenance	3.9(-8)	4.1(-7)
	Rupture	1.6(-7)	7.0(-8)
MSIV	Maintenance	1.5(-6)	6.9(-6)
	Rupture	1.4(-6)	1.1(-5)
TT	Maintenance	0	0
	Rupture	6.7(-7)	2.0(-6)
Total	Maintenance	1.6(-6)	7.3(-6)
	Rupture	2.3(-6)	1.3(-5)

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Supplement 7 (SSER 7) to the Safety Evaluation Report on Long Island Lighting Company's application for a license to operate the Shoreham Nuclear Power Station, Unit 1, located in Suffolk County, New York, has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission. This supplement addresses several items that have been reviewed by the staff since the previous supplement was issued.

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