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MEMORANDUM FOR: Commissioner Gilinsky

FROM: William J. Dircks
Executive Director for Operations

SUBJECT: SHOREHAM ECCS

Your June 28, 1984 memorandum asked if the ECCS pumps at Shoreham meet the regulations.

Enclosed are several staff evaluations which provide our basis for concluding that these pumps will satisfy the applicable General Design Criteria.

Enclosures 1 and 2 are excerpts from the fire protection evaluations contained in SSER 1 and 2. Note particularly Sections 9.5.3 and 9.5.6 on pages 9-9 and 9-11 of Enclosure 1 and the final paragraphs on page 9-1 of Enclosure 2. For clarity, elevation 8' is the bottom floor of the reactor building where these pumps are located and where the applicant's additional fire protection measures described in Enclosure 1 are located.

With regard to flooding of the ECCS pump level of the reactor building, we have determined that plant indications/alarms provide adequate information for plant operations to isolate any design basis pipe breaks in the reactor building. We conclude in Enclosure 3 that the pipe break protection in the reactor building meets GDC 3. Compliance with GDC 4 ensures that the equipment in the reactor building, including ECCS pumps, are not subject to common mode failure due to flooding. That is, no single pipe break in the reactor building can disable the ECCS functions. Therefore, GDC 35 is met for the worst case design basis internal flooding event in the reactor building. Enclosure 4 discusses another potential concern, namely flooding due to procedural errors during maintence. Enclosure 5, incorporates a BNL PRA type evaluation of the potential for flooding due to maintenance procedure errors, a beyond-design-basis event, and shows that the probability of such an event is acceptably low.

In addition to the design basis calculations, and evaluations of maintenance induced flooding, the staff has performed inspections and calculations to determine available time for operators to secure and mitigate the flooding from postulated breaks in the various piping systems inside the reactor building. Protection of vital instrumentation, junction boxes, and components of safety grade systems, were examined as to their susceptibility for flooding or spray. In most cases, several hours were available for the operators to identify and secure the flooding. In order to bound the problem, two

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coincident errors were assured in the limiting system to obtain a conservatively large flooding rate; the results of this scenario indicate in excess of two hours for the operators to take action. In summary, we have considered the man-machine interface as well as the design-basis and PRA aspects and find both are acceptably resolved.

(Signed) William J. Dircks

William J. Dircks
Executive Director for Operations

Enclosures:
1. Pages 9-1 - 9-12 of Shoreham SSER-1
2. Page 9-1 of Shoreham SSER-2
3. Pages 3-2 - 3-4 of Shoreham SSER-4
4. Memo (Mattson to Denton) dtd 12/29/83
5. Memo (Eisenhut to Starostecki) dtd 5/4/84

cc: Chairman Palladino
Commissioner Roberts
Commissioner Asselstine
Commissioner Bernthal
SECY
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OPE
EDO

NUREG-0420
Supplement No. 1

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 1981

9 AUXILIARY SYSTEMS

9.1.4 Fuel Handing System

In the Safety Evaluation Report, we concluded that the fuel handling system met the intent of Branch Technical Position ASB 9-1, "Overhead Handling Systems for Nuclear Power Plants." We also concluded that it will perform its safety function and is, therefore, acceptable.

In letters dated December 22, 1980 and February 3, 1981, the applicant was requested to establish the extent to which their heavy load handling operations satisfy the guidelines of NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." This NUREG addressed unresolved safety issue A-36. Further, the applicant was requested to identify the changes and modifications which would be required to fully satisfy these guidelines. The applicant will submit the results of their review against NUREG-0612 guidelines at a later date. Since this effort will extend over some period of time, certain measures that could be readily implemented such as identifying safe load paths, the development of procedures, operation training and crane inspections, testing and maintenance, were separately identified in Enclosure 2 to the December 22, 1980 letter. We require the applicant to implement these interim actions prior to the final implementation of the NUREG-0612 guidelines and prior to receipt of their operating license.

Based on our review of the Final Safety Analysis Report and the applicant's July 31, 1981 commitment to the interim position, we continue to believe that the fuel handling system meets the intent of Branch Technical Position ASB 9-1 and is in conformance with the requirements of General Design Criteria 2 and 61 relating to its protection against natural phenomena and safe fuel handling and the guidelines of Regulatory Guides 1.12 and 1.29 with respect to overhead crane interlocks and maintaining plant safety in a seismic event. The fuel handling system is, therefore, acceptable. We further conclude that implementation of the interim actions of NUREG-0612 prior to final implementation of NUREG-0612 guidelines and prior to receipt of the operating license provides reasonable assurance of safe handling of heavy loads until NUREG-0612 can be fully implemented and is, therefore, acceptable.

9.5 Fire Protection System

9.5.1 Introduction

We have reviewed the Shoreham fire protection program reevaluation and fire hazards analysis submitted by the applicant by letter dated June 1977. The Shoreham reevaluation was in response to our request to review their fire protection program against the guidelines of Appendix A to Branch Technical Postion (BTP) APCSB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." As part of our review, we visited the plant site to examine the relationship of safety-related components, systems, and structures in specific plant areas to both combustible materials and to fire detection and suppression systems. The overall objective of our review was to ensure that, in the event of a fire, Shoreham personnel and the plant equipment would be adequate to safely shutdown the reactor, to maintain the plant in a safe shutdown conditon, and to minimize the release of radioactivity to the environment.

Our review included an evaluation of the automatic and manually operated water and gas fire suppression systems, the fire detection systems, fire barriers, fire doors and dampers, fire protection administrative controls, and the fire brigade size and training.

On October 27, 1980 the Commission approved for publication in the Federal Register a new rule 10 CFR 50.48 and its Appendix R to 10 CFR Part 50, delineating certain fire protection provisions for nuclear power plants licensed to operate prior to January 1, 1979. Although this fire protection rule does not apply to Shoreham, we used the contents of this rule also in the evaluation of the fire protection program.

The applicant has been informed that all fire protection modifications have to be implemented prior to fuel load. Portions of our evaluation are based upon verbal commitments by the applicant. Our final evaluation is dependent upon adequate documentation of these commitments.

9.5.2 Fire Protection Systems Description and Evaluation

9.5.2.1 Water Supply Systems

The fire water supply system consists of two fire pumps separately connected to a 12-inch cement lined cast iron underground fire water loop. The fire pumps are rated at 2,500 gpm at 125 psig head. One of the fire pumps is electric deiven and is fed from two sources of offsite power. The other fire pump is deiven by a diesel engine which has its own batteries and battery chargers for starting power. The fire pump installation conforms to the guidelines of NFPA 20, "Standard for the Installation of Centrifugal Fire Pumps." The diesel driven and motor driven fire pumps and their associated controls are separated by a 3-hour fire rated wall equipped with 3-hour fire rated doors.

Two 350,000-gallon water storage tanks provide water for fire protection. Three hundred thousand gallons of the 350,000 gallons of water in each tank are reserved for fire protection by locating connections to the tanks for other services at the 300,000-gallon level. The two tanks will be filled automatically by the station well water pumps which can refill one tank within 8 hours. Each tank is heated to maintain the temperature above 42°F by an electric immersion tank heater. Each fire pump takes suction from a separate tank. A valved, normally open cross-connection between the two suction lines is provided within the fire pump house. Each tank is equipped with instrumentation to sourd an alarm in the main control room when a tank reaches the 300,000-gallon mark. If a leak is detected in one tank, the piping can be manually aligned to isolate the leaking tank and have both fire pumps take suction from the other tank.

A 30-gpm pressure maintenance pump (jockey pump) maintains the system pressure. The fire pumps start automatically on low header pressure. If the fire water supply system pressure falls to 100 psi, the electric driven fire pump starts automatically. As the pressure falls to 85 psi, the diesel-driven fire pump starts automatically. The fire pumps can also be started manually from the control room and at the pumps. Separate alarms are provided in the control room to monitor pump operation, diesel-driven fire pump fuel oil day tank level, electric motor-driven fire pump breaker tripped, and diesel-driven fire pump relief valve high flow.

The water flow requirement for the fire suppression system requiring the greatest water demand for areas containing or exposing safety-related equipment is 500 gpm and, coupled with 750 gpm for hose streams, totals a water demand of 1250 gpm. Since the system can deliver 2500 gpm at rated pressure with one pump out of service, the fire water supply system is adequate. Based on our review, we conclude that the fire water supply system meets the guidelines of Section C.2 of Appendix A to BTP ASB 9.5-1 and, therefore, is acceptable.

9.5.2.2 Sprinkler and Standpipe Systems

The automatic and manual sprinkler (Spray) systems and the manual hose station standpipe system are connected to the outside fire protection underground main as follows:

1. Turbine Building - independent connections to the interior fire header.

2. Automatic systems in the reactor building and radwaste building connected into hose station riser pipes - one connection to underground.

3. Control Building - one connection to underground.

All control and isolation valves for the sprinkler and standpipe systems are electrically supervised. All other major valves are locked open. Also, actuation of any water fire-suppression system will cause a fire pump to start on a low head pressure signal.

The automatic sprinkler systems, e.g., wet pipe sprinkler system, preaction sprinkler systems, and deluge spray systems, are designed to the requirements of National Fire Protection Association (NFPA) Standard No. 13, "Standard for Installation of Sprinkler Systems," and NFPA Standard No. 15, "Standard for Water Spray Fixed Systems."

The areas that are equipped with water suppression systems include the following:

1. Personnel tunnel

2. Office and service building, receiving and storage, print, record and file, oil, and store rooms.

3. Warehouse

4. Auxiliary Boiler Room

5. Diesel engine driven fire pump fuel tank area

6. Low level storage room and boiler area in the radwaste building

7. Portions of the turbine building

Preaction sprinkler systems are provided for the following areas:

1. Hydrogen seal oil unit

2. Lube oil room

Automatic deluge systems are provided for the following areas:

1. Main transformers

2. Normal station transformer

3. Reserve station transformer

Manually actuated deluge systems with open nozzles and separate detection systems are provided for the following areas:

1. Charcoal filter beds in each of the two reactor building standby ventilation filter trains

2. HPCI and RCIC turbine lube oil area (will be modified to be automatic)

3. Ventilation exhaust charcoal filter train radwaste building

4. Turbine driven reactor feed pumps

5. Primary containment purge filter train - reactor building

We were concerned that a rapidly developing fire at the HPCI turbine-driven pump would affect the adjacent RCIC pump and would threaten vertical safety-related cable trays in the area before the manual suppression system would be actuated. At our request, by letter dated July 10, 1981, the applicant agreed to modify the existing manually actuated deluge system for the HPCI/RCIC equipment area to an automatic pre-action actuation system.

Manual hose stations are located throughout the plant to ensure that an effective hose stream can be directed to any safety related area in the plant. The standpipe systems are consistent with the requirements of NFPA 14, "Standpipe and Hose Systems for Sizing, Spacing, and Pipe Support Requirements."

Based on our review, we conclude that the water suppression systems meet the guidelines of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

9.5.2.3 <u>Gas Fire Suppression Systems</u>

Total flooding low pressure carbon dioxide suppression systems are provided for the following areas:

1. Diesel generator rooms

2. MG room

3. Battery room

4. Emergency switchgear room

5. Relay room (cable spreading room)

6. Normal switchgear room

7. Cable tunnel

8. Turbine generator bearings

CO_2 hose reel stations are located at the entrances to the main control room and at various locations throughout the turbine and control building.

Carbon dioxide protected rooms and areas are provided with local warning alarms, delayed operation,a nd lockouts for personnel protection.

The low pressure carbon dioxide CO_2 system consists of fire detection, storage tank distribution piping and valves, discharge devices, and associated instrumentation control room. A system of rate compensated thermal detectors is provided for automatic actuation of the carbon dioxide extinguishing systems. A time delay of sufficient time to enable personnel to leave the area is provided for each system. Activation of the system may also be accomplished manually at local points.

At our request the applicant verbally agreed to provide a 30 minute soak time of the CO_2 system for the relay room (cable spreading room) to insure extinguishment of a postulated fire. The present system is designed for a 50% concentration for 20 minutes.

We have reviewed the design criteria and bases for the CO_2 fire suppression systems. We conclude that these systems are in accordance with the applicable portions of NFPA 12, satisfy the provisions of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

9.5.2.4 Fire Detection Systems

The fire alarm system consists of both high and low voltage ionization detectors, low voltage duct detectors, heat and photoelectric detectors and various control and power supply panels which feed the data to a control room security console. The fire alarm system through the security console gives both audible and visual alarms in the plant control room. Standby power is provided by either an emergency AC bus or the battery system for the security system. Fire detection systems will be installed in all areas.

The fire detection systems will be installed according to HFPA 72D, "Standard for the Installation, Maintenance, and Use of Proprietary Protective Signaling Systems."

The control room security console provides audible and visual indication of an alarm or trouble condition in the fire alarm system. The console supplies an output to a common audible alarm in the main control room upon indication of a fire detection or system trouble condition. The security console also provides visual output of alarm conditions via a CRT screen in the control room and one of two automatic line printers. All alarm signals are fed to a data processor computer at the control room security console for information, storage, and indexing. Instant recall and line printer printout of previous trouble or alarm signals are possible.

We were concerned that an open or break in the non-Class A circuit of the fire alarm system from the relay room to the control room would eliminate all fire alarm signals. At our request, by letter dated July 10, 1981, the applicant provided further description of circuits from the interface panel in the relay room to the CRT console and printer in the control room. The interface panel in the relay room is connected by a four-conductor cable to the computer for the fire detection and station security system console, located in the control room. A second parallel four-conductor cable is provided for this interface wiring to provide a second path should a conductor break. The alarms appear on the CRT in this console and the printer associated with it. Simultaneously, they also appear on the CRT and printer located in the Security Building. The entire wiring for the detection system is supervised and any broken or shorted wire will alarm at both locations.

Based on the applicant's description of the redundant circuits between the relay room and control room, we conclude that the fire alarm system meets the guidelines of Appendix A to BTP 9.5-1 and is, therefore, acceptable.

9.5.3 Other Items Related to Fire Protection Programs

9.5.3.1 Fire Barriers and Fire Barrier Penetrations

Walls that separate safety-related buildings are three-hour fire rated. The floor/ceiling assemblies separating areas in buildings containing safe shutdown systems are also 3-hour fire rated barriers. Fire rated barriers are constructed of reinforced concrete or masonry block construction. Concrete fire barriers have been evaluated by comparison with designs which have been tested and rated in accordance with NFPA-251 and ASTM E-119. For fire areas not having a 3-hour fire rated assembly, we evaluated each individually with respect to its fuel load, fire suppression and detection systems, and proximity to safe shutdown equipment and conclude that the fire rated assemblies provded are adequate for the areas affected, meet the guidelines in Section D.i.j of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

The design of penetration seals used has not been documented. The applicant has verbally agreed to provide specific 3-hour U.L. designs for all fire penetration seals used in the penetration cable trays, conduits, and piping which pass the penetration qualification tests including the time-temperature exposure fire curve specified by ASTM E-119, "Fire Test of Building Construction and Materials." We have concluded that the fire seals meet the guidelines of Appendix A to BTP ASB 9.5-1 and are, therefore, acceptable.

9.5.3.2 Fire Doors and Dampers

The applicant has indicated that the following areas contain 3-hour fire rated dampers where ventilation ducts penetrate the 3-hour fire wall:

1. Relay Room

2. Control Room

3. Computer Room

4. Emergency Switchgear Rooms

5. Battery Rooms

In ducts penetrating the fire barrier walls surrounding the safety-related equipment, a fire damper of 1½-hour rating is used. Some areas also contain motorized 1½-hour fire dampers in which the motorized assembly, including cables, are not U.L. listed. We are concerned that the unlisted assemblies will prevent the fire dampers from performing its function. We require that all such operators be replaced with approved listed operators or a surveillance program be developed and included in the plant Technical Specifications to assure an adequate level of reliability.

9.5.4 Emergency Lighting

Eight-hour battery pack emergency lights are required for areas of the plant necessary for safe shutdown. The applicant will install self-contained eight-hour battery pack emergency lighting in all areas of the plant which could be manned to bring the plant to a safe cold shutdown and in access and egress routes to and from all fire areas.

We conclude that the emergency lighting meets the requirements of Appendix to BTP ASB 9.5-1, and, also, the provisions of Section III.J of Appendix R to 10 CFR Part 50 and is, therefore, acceptable.

9.5.5 Fire Protection for Specific Areas

9.5.5.1 Control Room

The control room complex is separated from all other areas of the plant by 3-hour fire rated walls, ceiling/floors assemblies, floors and doors. All ventilation ducts penetrating these barriers have 3-hour fire rated dampers. The control room complex peripheral rooms, except the visitors gallery which has bullet-resistant noncombustible materials, are constructed to provide a minimum fire rating of 1 hour. The ventilation openings in the peripheral rooms are protected with 1½-hour rated fire dampers. At our request the applicant has agreed to install additional smoke detectors in these rooms which will alarm and annunciate in the control room.

All cabinets, consoles, and the ventilation exhaust system within the control room have ionization fire detectors installed. The main control room ventilation system can be remote manual isolated from the main control room as it has capability of being used as a smoke removal system.

Manual fire fighting is provided through the use of portable extinguishers and CO_2 hose reels (supplied from the station hose pressure CO_2 storage tank) which are located outside the main control panel at the access door. At our request the applicant has agreed to provide and increase hose length of 100 feet for the 1½-inch water hose stations also located just outside the control room for additional protection inside the control room. This increased hose length will be provided for FHR Nos. 1 and 71.

The suspended ceiling is of the aluminum egg crate type design.

The applicant has agreed to install the emergency shutdown panel so that alternate shutdown capability exists independent of the control room.

Based on our review, we conclude that the control room fire protection meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

9.5.5.2 Cable Spreading Room (Relay Room)

The single cable spreading room is separated from the balance of the plant by 3-hour fire-rated walls and floor/ceiling assemblies. Three-hour fire rated fire dampers are provided for all ventilation ducts that pierce the walls. At our request, the applicant has verbally agreed to upgrade to 2 hours a shaft in the southeast corner of the room, elevation 44, as well as provide 3-hour fire damps for any ducting penetrating this shaft. Exits are provided at each end of the room.

Automatic fire detection by Class 1E seismic Category I heat detectors will actuate a total flooding CO_2 suppression system, isolate ventilation, initiate local predischarge warning, and annunciate in the main control room. At our request the applicant verbally agreed to increase the 50% concentration to 30 minutes soak time. Area, duct, and panel-mounted smoke detectors are also provided for the room.

A CO_2 hose reel is located at the south end of the room as backup in addition to portable fire extinguishers. Standpipe water hose stations are provided on the outside of the main exits from the room.

We were initially concerned that a fire would affect redundant shutdown systems located in the cable spreading room. However, the applicant has installed an alternate shutdown capability independent of the cable spreading room (refer to Section 7.4.3 of this report). The fire protection for the cable spreading room meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

9.5.5.3 Containment and Reactor Building

The primary containment will be inerted during normal operation hence eliminating any fire hazard associated with the lubricating oil of the recirculation pumps.

The containment and reactor building fire protection features include hose stations, fire detectors, fire extinguishers, automatic sprinklers, manual deluge and fire control barriers. Fire detectors are distributed throughout the areas with alarm and annunication in the control room.

In the reactor building at elevation 8', we were concerned that a fire at the HPCI turbine driven pump could affect the adjacent RCIC turbine pump as well as vertical safety related cable trays running up the walls in the area. At our request, the applicant by letter dated May 21, 1981, agreed to provide a 9-foot high 3-hour fire rated barrier between the vertical cable trays and the adjacent RCIC pump. Also, by letter dated July 10, 1981, the applicant agreed to modify the existing manually actuated deluge system for the HPCI/RCIC equipment area to an automatic pre-action actuation system.

We were concerned that if the preset single feed to the reactor building should fail, both the primary and secondary fire protection would be lost. At our request, the applicant agreed to provide a secondary feed from the underground to the reactor building, as well as necessary valves such that primary or secondary water fire protection will always be provided. The fire protection for the containment and reactor buildings meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

9.5.5.4 Emergency Diesel Generator Rooms

Each of the emergency diesel generators is in its own protected room separated by walls, floor, ceiling/floor assembly and doors having a minimum fire rating of 2 hours. Automatic fire detection by Class 1F, seismic Category I heat detectors actuate a total flooding CO_2 suppression system, isolate ventilation (with the exception of the diesel air intakes), shut down the diesel fuel oil transfer pumps for the diesel, actuate the local predischarge warning and annunciate in the main control room. Area smoke detectors are also installed for these rooms. Backup fire protection is provided by protable extinguishers plus manual hose stations located in the room. Smoke purging is provided for through the normal ventilation system.

The diesel fuel oil storage tanks are buried and located at a distance of more than 50 feet from the diesels.

Based on our evaluation, we conclude that the fire protection for the diesel generator rooms meets the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

9.5.5.5 Other Plant Areas

The applicant's Fire Hazards Analysis addressed other plant areas not specifically discussed in this report. The applicant has committed to install additional detectors, portable extinguishers, and fire barriers prior to fuel load. We find the fire protection for these areas, with the commitment made by the applicant, to be in accordance with the guidelines of Appendix A to BTP ASB 9.5-1 and is, therefore, acceptable.

9.5.6 Fire Protection of Safe Shutdown Capability

The applicant's post-fire safe shutdown analysis of the fire protection of safe shutdown is presented in three letters.

By letter dated May 21, 1981, the applicant provided a comparison of the plant design with the requirements of Appendix R. The applicant also provided a separation analysis of cables within the reactor building by letter dated February 10, 1981 and analysis of shutdown circuits outside the reactor building by letter dated July 10, 1981.

The applicant's post-fire safe shutdown analysis demonstrated that systems needed for hot shutdown and cold shutdown are redundant and that one of the redundant systems needed for safe shutdown would be free of fire damage, by providing separation, fire barriers, and/or alternative shutdown capability.

The safe shutdown analysis considered components, cabling, and support equipment for systems needed to shut down. Thus, in the event of a fire, at least one train of systems free of fire damage would be available to achieve and maintain hot shutdown or to proceed to cold shutdown. For hot shutdown, at least one of the following shutdown systems would be available: (1) the Reactor Core Isolation Cooling System, (2) the High Pressure Coolant Injection System, and (3) a combination of the pressure relief system, the core spray system and residual heat removal (RHR) system. For cold shutdown, an appropriate portion of the RHR system would be available.

For equipment located in the primary containment, no fire protection features are provided because the containment atmosphere will be inert.

For equipment located in the reactor building (secondary containment), the applicant provided a cable separation analysis which divided the reactor building into overlapping 45 degree segments. The applicant assumed that all components, the cables and raceways, in a given segment were lost due to a fire; yet demonstrated the capability to shut down still existed. We have reviewed the cable separation analysis and conclude that it is an acceptable method of demonstrating that adequate separation exists between the redundant trains. Additionally, the applicant has committed (by July 10, 1981 letter) to verify that the "as-built" design has a minimum 20 ft separation between redundant safety-related components.

The secondary containment is a cylindrical structure with a 135-foot outside diameter and 240 ft high with 2-foot concrete walls. There are six complete elevations with each elevation containing large open penetrations. The area between the primary and secondary containment is one fire area.

Throughout the reactor building both smoke and temperature detectors are installed with alarm and annunciation in the control room. All cable trays have solid bottoms with covers or ladder type with solid covers attached to both sides. All vertical trays incorporate fire stops within the tray and external to all trays where they penetrate floor levels. Fire stops are provided at the midpoints when the elevation is more than 25 ft.

The two main vertical safety-related cable risers are located at 138° and 223° azimuth, extend from elevation 8' to elevation 40' and are separated by 85 ft. The applicant's analysis demonstrated that a 45° segment in which a fire caused the disability of all cables and raceways in that segment, a separation distance of 20 ft on the inside of secondary containment existed and 35 ft existed on the outside. The applicant then rotated this segment 22.5° for additional verification and overlapping.

The applicant provided fire detection, alarm, annunciation, water spray systems for the RBCV's charcoal filters, hose stations, automatic pre-action sprinkler systems, fire barriers, two fire main feeds and portable equipment for secondary containment. Due to the preceding separation distances and protection provided, an automatic suppression system is not needed for protection against a transient exposure fire.

For equipment in areas outside the reactor building, the applicant has identified seven areas which contain cable for redundant shutdown equipment: the relay room, the control room, the diesel-generator rooms, the emergency switchgear room, the fuel oil pumphouse rooms, the screenwell, and the HVAC room.

In the diesel-generator rooms, the emergency switchgear room, the fuel oil pumphouse rooms, and the screenwell, redundant equipment is separated by a 3-hour fire-rated barrier. Cabling to this equipment is contained in underground ducts. In the event that fire disables redundant equipment in the HVAC room, control room, or relay room, a remote shutdown panel is provided in the reactor building (refer to section 7.4.3 of this report).

Sections 7.4.1.4, 7.5.1.4, and 7.5.1.5 of the FSAR describe the remote shutdown panel's design and capability. By letter dated May 21, 1981, the applicant addressed Section III.L of Appendix R. The design objective of the remote shutdown panel is to achieve and maintain cold shutdown in event of a fire disabling the relay room or the control room. The reactor core isolation cooling (RCIC) system, safety/relief valves and one division of the residual heat removal (RHR) system can be controlled from the remote shutdown panel to achieve cold shutdown.

The design of the remote shutdown panel complies with the performance goals outlined in Section III.L. Reactivity control will be accomplished by a manual scram before the operator leaves the control room. The RCIC system will provide reactor coolant makeup and the RHR system and the safety relief valves will be used for reactor heat removal. Reactor water level, reactor pressure, suppression pool water level and temperature, and drywell pressure and temperature are among instrumentation available at the remote shutdown panel to provide direct reading of process variables. The remote shutdown panel will also include instrumentation and control of support functions needed for the shutdown equipment. Procedures for use of the remote shutdown panel include sequencing of equipment and operator actions.

Based on the above, we conclude that the fire protection of safe shutdown capability meets the guidelines of Appendix A to BTP 9.5-1 and is, therefore, acceptable.

9.5.7 Administrative Controls and Fire Brigade

The administrative controls for fire protection consist of the fire protection organization, the fire brigade training, the controls over combustibles and ignition source, the prefire plans and procedures for fighting fires and quality assurance. The fire brigade will be composed of five members per shift. To have proper coverage during all phases of operation, members of each shift crew will be trained in fire protection in accordance with our guidance including Regulatory Guide 1.101, "Emergency Planning for Nuclear

Power Plants." The applicant has agreed to implement the fire protection program contained in the staff supplemental guidance "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated August 29, 1977, including (1) fire brigade training, (2) control of combustibles (3) control of ignition sources, (4) fire-fighting procedures, and (5) quality assurance.

The applicant will implement the plant administrative controls and procedures before fuel loading.

We conclude that, with these commitments, the size of the fire brigade, the necessary equipment, and the adequacy of the training, training will conform to the recommendations of the National Fire Protection Association, to Appendix A to BTP ASB 9.5-1, and to our supplemental staff guidelines and are, therefore, acceptable.

9.5.8 Technical Specification

The applicant has committed to follow our Standard Technical Specifications. We find this acceptable.

9.5.9 Appendix R Statement

On October 27, 1980, the Commission approved for publication in the Federal Register a new rule §50.48 and Appendix R to 10 CFR Part 50, delineating certain fire protection provisions for nuclear power plants licensed to operate prior to January 1, 1979. Although this fire protection rule does not apply to Shoreham, we used the technical requirements of this rule as guidance in our evaluation of the fire protection program.

By letter, dated May 21, 1981, the applicant provided a comparison of its fire protection program with the NRC guidelines given in the technical requirements of Appendix R. The applicant's program is in conformance with these guidelines.

9.5.10 Conclusion

There is one unresolved fire protection item to be reviewed. This item involves the fire dampers (Section 9.5.3.2). We will report our review of this item in a supplement to the Safety Evaluation Report. The applicant has been informed that all fire protection items need to be resolved prior to fuel loading.

NUREG-0420
Supplement No. 2

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

February 1982

9 AUXILIARY SYSTEMS

9.4.1 Control Room Air Conditioning System

In our Safety Evaluation Report, we stated that all control room air conditioning system outside air intakes and exhausts are tornado missile protected. By letter dated November 13, 1981, we were informed by the Shoreham Resident Inspector that the control room air conditioning system east air intake is not tornado protected and that all the piping from the east air intake is not in a tornado protected structure.

The east air intake is a remote intake located in the radwaste building and therefore penetration of missiles via this air intake will not affect safe plant shutdown and will not prevent operation of the control room air conditioning system since the air intake located in the control building is tornado missile protected. Since only one air intake is necessary for operation of the control room air conditioning system, protection of the remote air intake is not required. Many plants have only one air intake. Therefore, our previous conclusion that the control room air conditioning system is acceptable remains unchanged.

9.5 Fire Protection System

9.5.3.2 Fire Doors and Dampers

In Supplement No. 1 to the Safety Evaluation Report, we stated that certain areas of the plant contained motorized 1½-hour fire dampers in which the motorized assembly, including cables, are not U.L. listed. We were concerned that the unlisted assemblies would prevent the fire dampers from performing their function.

By letters dated September 25, 1981 and October 13, 1981, the applicant provided additional information. The installation has been modified to include solenoid and motor circuits approved by U.L. As a result, we now conclude that the fire dampers, as modified, meet the design guidelines of Section D.1.j of Appendix A to BTP ASB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," and are, therefore, acceptable.

Based on our review, we conclude that the Shoreham fire protection program will meet the technical requirements of Appendix R to 10 CFR Part 50, when committed modifications have been completed, meets the guidelines of Appendix A to BTP ASB 9.5-1, meets the requirements of General Design Criterion 3, and is, therefore, acceptable.

NUREG-0420
Supplement No. 4

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 1983

in Revision 5 to the Design Assessment Report (DAR). The 30 representative piping systems were located throughout the reactor building and contained the least design margin available for accepting potential increases in dynamic loads. It was shown that the pipe stresses and support loads for these 30 piping subsystems were within design allowables when reassessed to the NUREG-0808 loads. However, as a result of a meeting on August 9, 1982, with the applicant, the staff concluded that in addition to reassessing the 30 piping systems with the least design margin, the applicant should also reevaluate all piping systems affected by the high frequency exceedances associated with the NUREG-0808 loads. The applicant committed to perform this reevaluation of high frequency exceedance in a letter from J. L. Smith to H. R. Denton dated August 20, 1982.

In a letter from J. L. Smith to H. R. Denton dated March 17, 1983, the applicant submitted the results of the high frequency reevaluation. The results included a reevaluation of an additional 67 piping subsystems.

In all cases, it was found that the piping and supports that are affected by the NUREG-0808 high frequency load increases were designed with sufficient design margin to accommodate the increase.

Therefore, based on the results of the assessment performed by the applicant in Revision 5 of the DAR and on the results of the reevaluation reported in the March 17, 1983, letter, the staff concludes that the applicant has satisfactorily demonstrated that the piping and supports on the Shoreham facility have been adequately designed to withstand the suppression pool hydrodynamic loads associated with the BWR Mark II containment. Thus, the confirmatory item associated with the ability of the Shoreham piping systems to accommodate steam condensation oscillation and chugging loads is considered to be resolved.

3.12 Reactor Building Internal Flooding

3.12.1 Background

The NRC staff had expressed concern about the potential for flooding safety-related equipment in the event of a pipe break in the Shoreham reactor building (memorandum from R. W. Starostecki, NRC Region I, to D. G. Eisenhut dated June 8, 1982).

Both core spray pumps, all four RHR pumps, the high pressure coolant injection (HPCI) turbine and pump, and the reactor core isolation cooling (RCIC) turbine and pump are located on the lowest level (8-foot elevation) of the reactor building. There are no flood walls or barriers separating redundant trains of this equipment. The applicant has provided nonsafety-related pumps and alarms, safety-related flooding alarms, and one 100-gpm safety-related pump to return water from the 8-foot elevation sump to the suppression pool. The small safety-related pump-back system pump has been provided to deal with postulated post-LOCA leakage in the reactor building; the adequacy of the pump for this purpose has been addressed separately.

The applicant proposes to rely on the safety-related flooding alarms, fluid system instrumentation, and operator actions to prevent flood damage to essential reactor building equipment as a result of high- and moderate-energy pipe breaks during normal operation. The adequacy of the applicant's proposals to protect against internal flood damage at the 8-foot elevation of the reactor building during normal operation is addressed below.

3.12.2 Evaluation

The applicant provided an analysis of the effects of pipe breaks in the reactor building in Appendix 3C to the Shoreham Final Safety Analysis Report (FSAR). The applicant noted in Appendix 3C that the maximum flooding rate at the 8-foot elevation of the reactor building would result from an RHR pump discharge line break with a leakage rate of about 2900 gpm at 350 psig. The applicant determined that other moderate-energy line cracks as well as high-energy line breaks in the reactor building would have a lower leakage rate; thus, an evaluation of the RHR leak was used as the limiting condition for which flood protection is provided. Plant alarms followed by operator entry into the reactor building would be used to determine the existence and location of pipe breaks in the reactor building. The applicant estimates that the limiting RHR system leak could be detected, identified, and isolated within 30 minutes. The existence of a leak would be alarmed almost immediately by redundant, safety-related reactor building flooding alarms, which alarm at a water level of 1/2 inch at the 8-foot elevation of the reactor building. For the limiting condition--an RHR discharge line crack during shutdown cooling, or refueling operations--the applicant calculates that the water level at the 8-foot elevation would approach a depth of 22 inches in the 30 minutes allowed for operator action. Because the postulated line crack would not affect the availability of offsite power, the nonsafety-related sump pumps would be available to reduce the 30-minute flooding depth to 20 inches. The applicant states that shutdown cooling capability would be maintained for this maximum leakage if isolation takes place within 30 minutes.

On August 24, 1982, a meeting was held at the Shoreham site between the applicant and members of the NRC staff. After a tour of the reactor building 8-foot elevation, the staff expressed a concern that identification of a specific leak location and isolation of that leak within 30 minutes may not be possible for all break locations. By letter dated September 9, 1982, the applicant was asked to demonstrate that plant procedures and instrumentation would be adequate to ensure leak detection, identification, and isolation within 30 minutes for all postulated pipe breaks in the reactor building. The applicant was also asked to demonstrate that access to the 8-foot elevation for the purpose of break location identification would be possible, considering the accumulation of potentially radioactive and/or thermally hot water on the elevation, and that the accumulation of water could submerge the leak.

By letter dated December 3, 1982, the applicant provided the additional information requested above. The applicant noted that the analysis in Appendix C to the FSAR was based on preventing flood damage to RHR flow indication instrumentation located approximately 2 feet above the 8-foot elevation floor. The applicant stated, however, that this instrumentation is not required for safe shutdown. The applicant further stated that flooding depths of up to 4 feet above the 8-foot elevation floor could be postulated before damage to essential safe shutdown equipment would be incurred. However, the applicant provided the information in the following paragraphs to demonstrate that postulated leaks could be isolated before a flooding depth of 2 feet is attained.

The applicant's submittal of December 3, 1983 addressed the limiting RHR system pipe crack as well as other postulated leaks in the reactor building. In all cases, redundant safety-related instrumentation would alarm a flooding depth of 1/2 inch on the 8-foot elevation floor. The applicant demonstrated that safety-related instrumentation is available for the operator to identify and isolate a postulated 2900-gpm RHR system leak from the control room in less than 30 minutes. The next largest leakage flow (650 gpm) would occur from an HPCI system leak. At 650 gpm, approximately 2 hours would be available to isolate the leak before the flooding depth reached 2 feet. This postulated leak would not result in a harsh thermal or radioactive environment in the reactor building and would not prevent operator access for identification of the leak location.

In addition to RHR system leaks, the applicant also addressed reactor building pipe breaks that could result in radioactive or thermally hot leakage. A break in the hot water heating (HWH) system would flood the reactor building with hot water, but the flooding depth would be limited to 3 inches initially because of the limited system water inventory. With no operator action to isolate the leak, continued makeup to the HWH system at 25 gpm would leak to the reactor building, and the flood depth would approach 2 feet after several days. However, various indications would alert the operator to the system leakage, and the leak can be isolated from the control room. Aside from RHR system pipe cracks, only a break in the reactor water cleanup system could introduce radioactive leakage into the reactor building. The maximum leakage of 180 gpm from the system could be identified and terminated in the control room.

The applicant noted that although an RHR system crack would be most likely to be hidden by submergence as a result of flooding, the leak location can be identified and isolated from the control room. Other leaks would be less likely to be submerged because of the lower leakage rates versus height of the piping from the floor of the 8-foot elevation. Alarm response procedures and operating procedures are being modified to address both post-LOCA leaks and moderate-energy line cracks postulated to occur during normal operation. These procedures will direct the operator to start leak location identification walk-throughs on the 8-foot elevation to ensure leak detection before the leak is submerged. The applicant is also participating in the Boiling Water Reactor (BWR) Owners Group program to develop a secondary containment control procedure that will provide additional specific guidance for operator response to postulated flooding events.

3.12.3 Conclusions

The NRC staff has determined, on the basis of its review, that the applicant has adequately identified and provided internal flooding protection for systems and components at the 8-foot elevation of the reactor building required for safe shutdown in the event of pipe failures. The reactor building design meets the criteria set forth in Branch Technical Position (BTP) ASB 3-1 regarding protection of safety-related systems and components from postulated piping system failures. The design, therefore, meets the requirements of General Design Criterion (GDC) 4, "Environmental and Missile Design Bases," regarding flooding protection for pipe breaks. The NRC staff therefore, concludes that the reactor building design for protection against internal flooding is acceptable.

E. Sylvester

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

DEC 29 1983

MEMORANDUM FOR: Harold R. Denton, Director
Office of Nuclear Reactor Regulation

FROM: Roger J. Mattson, Director
Division of Systems Integration

SUBJECT: SHOREHAM REACTOR BUILDING - INTERNAL FLOOD PROTECTION

At the invitation of R. W. Starostecki, Director of the Division of Project and Resident Programs, Region I, I participated with Region I personnel in an on-site assessment of the adequacy of internal flood protection at the Shoreham plant. I was accompanied on this December 6, 1983, site visit by L. S. Rubenstein and E. Sylvester of my staff, who have been involved in the ongoing discussions with Region I.

The Region's question of flood protection adequacy first came to my attention in a memorandum to D. G. Eisenhut dated June 3, 1982, from Mr. Starostecki in which he requested NRR assistance to resolve several outstanding safety issues at Shoreham. We subsequently provided a safety evaluation report of our understanding of this concern to Mr. Starostecki by memorandum from T. Novak dated May 9, 1983. After several telephone conversations with Mr. Starostecki, it was decided to meet with him and other Region I personnel to pursue the issue.

At the December 6 site visit, we met with Mr. Starostecki, Mr. Charles Petrone, Resident Inspector for Shoreham, and Mr. Thomas Shedlosky, Senior Resident Inspector for Millstone, who has been assisting Mr. Petrone. They identified three separate internal flooding problems: (1) post-LOCA equipment leakage in the reactor building, (2) moderate and high energy pipe break flooding, and (3) flooding due to procedural errors during maintenance of reactor building fluid system components. After a tour of the facility with Long Island Lighting Company personnel, we and Region I personnel agreed that the safety-related reactor building sump pump provided adequate protection against the minor leakage expected after a LOCA. We (NRR and Region I) also agreed on the adequacy of the protection afforded essential equipment in the reactor building from pipe break flooding. We consider these two aspects of the flooding concern to be resolved. However, we concluded that further evaluation will be required to resolve the concern as it relates to flooding from maintenance procedure errors.

Internal floods resulting from maintenance procedure errors are currently beyond the scope of our deterministic review process. The scenario for Shoreham reactor building flooding postulates maintenance activities whereby fluid systems components are opened to the reactor building atmosphere, an operator erroneously opens isolation valve(s) to the component, and there is a failure to terminate the ensuing leak in time to prevent flooding of essential equipment. By memorandum from S. H. Hanauer to D. G. Eisenhut dated November 16, 1982, the staff documented an evaluation of the draft Shoreham probabilistic risk assessment of this accident sequence along with an evaluation of the Suffolk County consultant's report on the Shoreham PRA. The staff concluded that the maintenance flooding sequences do not contribute to risk significantly, subject to applicant verification of plant-specific event probabilities. The evaluation was sent to the Atomic Safety and Licensing Board for Shoreham by November 26, 1982 memorandum from T. Novak. The applicant has subsequently submitted a revised PRA of the potential for flooding due to maintenance errors. This submittal, dated December 2, 1982, has not been evaluated by the staff. The Division of Licensing has agreed to initiate an evaluation of the submittal by the Reliability and Risk Assessment Branch of the Division of Safety Technology to ascertain whether it confirms the staff's preliminary conclusion that the maintenance error type of flooding is not an undue risk. The regional and resident personnel will be kept informed of the outcome of that review, projected by DST for conclusion by the end of February, 1984. Messrs. Speis, Eisenhut and Starostecki have concurred in this approach.

L S Rubenstein

Roger J. Mattson, Director
Division of Systems Integration

cc: D. G. Eisenhut
T. Speis
R. Starostecki
L. Rubenstein
F. Rowsome
T. Novak
O. Parr
A. Thadani
A. Schwencer
J. Wilson
C. Petrone
R. Caruso
E. Sylvester

LB#2 Read.

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

MAY 4 1984

MEMORANDUM FOR: Richard W. Starostecki, Director
Division of Project and Resident Program

FROM: Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation

SUBJECT: SHOREHAM REACTOR BUILDING--INTERNAL FLOOD PROTECTION

On December 29, 1983, senior NRR management reviewed the results of an on-site assessment of internal flood protection at Shoreham. As a result of the December 6, 1983 site visit, all participants agreed that adequate provisions exist to protect essential equipment from pipe break flooding and from minor leakage after a LOCA. However, further evaluation remained to be done to resolve the flooding concern as it related to flooding from maintenance procedure errors.

Brookhaven National Laboratory (BNL), the contractor which is reviewing the Shoreham PRA, was tasked with an advance review of the probabilistic risk assessment of maintenance induced flooding which had been done by LILCO (see LILCO's December 2, 1982 submittal). The BNL evaluation is enclosed. It notes that some potential deficiencies exist in the Shoreham alarm response procedures for mitigating a flood. Otherwise, we have determined that the report confirms our previous conclusion that maintenance flooding sequences do not contribute significantly to risk. The BNL report will be published in the next SSER, to document the closure of this item. The modifications to the procedures will be listed as a confirmatory item, whose completion will be verified by a Region I inspector, prior to exceeding 5-percent power. The Region I inspector should verify that the revised procedures are consistent with the assumptions made in the BNL PRA for flooding alarm response by the operators.

Darrell G. Eisenhut, Director
Division of Licensing
Office of Nuclear Reactor Regulation

Enclosure

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

MAR 3 0 1984

MEMORANDUM FOR: Albert Schwencer, Chief
Licensing Branch #2
Division of Licensing

FROM: Ashok Thadani, Chief
Reliabiity and Risk Assessment Branch
Division of Safety Technology

SUBJECT: SHOREHAM FLOODING

We have completed the task requested in your memorandum to me dated January 30, 1984 on Shoreham Flooding.

With the help of our contractor, Brookhaven National Laboratory (BNL), we have reviewed the internal flooding analysis in the Shoreham Probabilistic Risk Assessment (PRA) study[1] and the Shoreham flooding submittal[2] dated December 2, 1982. Long Island Lighting Company (LILCO) found the Shoreham core vulnerable frequency (see Enclosure 1, p.4, for definition) initiated by flooding to be about $4x10^{-6}$/reactor-year. Maintenance-induced flooding contributes $1.5x10^{-6}$/reactor-year to this value, and pipe-break induced flooding contributes $2.4x10^{-6}$/reactor-year.

For the most part, we found the assumptions and methodology used to be reasonable. However, we have used more recent licensee event report (LER) data and a different model in reevaluating the flood initiating frequency. Our model used a Markov process model to determine the frequency of flood precursor events, and time-phased event trees to account for the effects of flooding to different levels.

We recognize 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. We have therefore performed an uncertainty analysis using the SAMPLE[3] program. We estimate that the mean value of the core vulnerable frequency of accidents initiated by flooding in the reactor building at Shoreham is $2x10^{-5}$/reactor-year, and the 95% upper limit is $7.5x10^{-5}$/reactor-year. The core vulnerable frequency due to maintenance-induced flooding has a mean value of $7x10^{-6}$/reactor-year, while the corresponding value for pipe-break induced flooding is $1.3x10^{-5}$/reactor-year.

Our review identified some potential deficiencies in the Shoreham alarm-response procedures for mitigating a flood. We note that the human error probability used by BNL assumed good alarm-response procedures. The core-vulnerable frequency may be higher than that estimated unless the procedures are corrected.

Our findings are discussed in the enclosures. Enclosure 1 is our evaluation; Enclosure 2 is the preliminary BNL report. We expect to receive the final

MAR 30 1984

BNL report in the middle of April, 1984, and we will transmit it to you when we receive it.

E. Chow (x24727) of RRAB has performed this assessment.

A C Thadani

Ashok Thadani, Chief
Reliability and Risk Assessment Branch
Division of Safety Technology

Enclosures:
As stated

cc: H. Denton
R. Mattson
D. Eisenhut
T. Speis

F. Coffman
E. Chelliah
[redacted]

ENCLOSURE 1

EVALUATION OF SHOREHAM FLOODING

1.0 Introduction

A memorandum[4] dated November 16, 1982 on our preliminary review of internal flooding at Shoreham reactor building was transmitted from Stephen Hanauer to Darrell Eisenhut. The preliminary review was performed on the draft report[5] submitted by Future Resources Associates, Inc. (FRA), the consultants for Suffolk County, and on the draft Shoreham PRA submitted by LILCO. The concern that FRA found that the draft Shoreham PRA underestimated the frequency of certain internal flooding acccident sequences by more than a factor of 1000.

Based on our preliminary review at that time, we believed that flood accident sequences did not contribute to risk significantly. However, we recommended LILCO to 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, LILCO submitted an analysis performed by its contractor Science Applications Inc. to respond to the FRA concern on Shoreham flooding. On June 24, 1983, LILCO submitted the final report on the Shoreham PRA which included the most up-to-date analysis on flooding.

With the help of BNL, we have 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, including a discussion of alarm-response procedures. Section 3 and 4 discuss the methodology and uncertainty analysis. Section 5 gives the summary and conclusions.

2.0 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 due to not isolating a system which is under maintenance or due to a rupture in the system. What follows is a description of each type of initiator event.

2.1.1 Maintenance-Induced Flood

LILCO has obtained operating experience based on LERs[6] for turbine-driven pumps and motor-driven pumps in ECC and RCIC systems. The LERs covered events up to 1978.

We have also obtained operating experience for the pumps; however, the LERs[7] that we examined covered events up to 1980. Using the more up-to-date data base on LERs, we estimate higher failure rates for the pumps. These failure rates were used to determine maintenance-induced flood event frequencies.

2.1.2 Pipe-Break-Induced Flood

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

The general approach that LILCO used to calculate the frequency of a flood initiated by a rupture in an ECC or RCIC system is as follows:
(1) LILCO identified the appropriate type and length of piping and number of components in an ECC or RCIC system susceptible to rupture.
(2) LILCO used the LER information in NUREG/CR-1363[8] and the estimates for leakage and rupture rates in WASH-1400[3] to calculate the rupture rates for various ECC systems.

Our review of BWR operating experience on flooding due to 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. LILCO did not include this event in its data base.

We note that the weld at Browns Ferry was mainly made of aluminum whereas the welds in HPCI system at Shoreham were made of stainless steel. However, we have included the Browns Ferry event in estimating the frequency of flood 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 is required to verify that tagging has been performed properly. If the electric power to an isolation valve is not removed due to operator errors, and a demand to open the valve occurs during the 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 due to an operator inadvertently operating a switch in the control room.

(2) During a 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 in the reactor building occurs, an operator must promptly identify the source of flood and isolate it before it reaches the 3'10" level which disables all ECC and RCIC components.

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

2.2.2 Procedures Review

We have reviewed the procedures for operators for mitigating a flood. We note that there are specific procedures at Shoreham for detecting and isolating leakages from ECC and RCIC systems. However, we note that the Shoreham alarm-response procedures specify only general guidelines for monitoring system parameters to determine the leakage location and for initiating the leak isolation. The procedures fail to include specific requirements in a checklist for operators to systematically check the operation parameters of ECC and RCIC systems. Since there are many system parameter indicators in the control room, the operators may fail to discover the abnormal system parameters. A checklist 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 responses. Regarding maintenance procedures for pulling and tagging breakers and for verifying such actions, LILCO stated that these procedures were available for maintenance.

3.0 Methodology Review

We have used a Markov model to determine the frequencies of maintenance-induced flood initiators due to maintenance on various components in ECC or RCIC systems. In a similar approach, we have also used another Markov model to determine the frequencies of rupture-induced flood initiators during transients, manual shutdowns, or tests.

The analyses submitted by LILCO assumed that when flood reaches 3'10", all ECCS and RCIC components would fail. The LILCO analysis did not develop the event trees according to the progression of a flood affecting various components at various elevations up to 3'10".

We used a time-phased approach to expand the flooding event trees submitted by LILCO into four phases. The four phases correspond to different components at different elevations. Based on 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.

4.0 Uncertainty Analyses

In view of the large uncertainties in the analysis, we have used a 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 our analysis. For example, in our analysis of time phase 4, conditional probability of 0.5 is assumed for a MSIV closure. However, the results cannot be non-conservative by more than a factor of 2.

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

Based on the SAMPLE calculation, we estimate that the mean value of the core vulnerable frequency* due to flooding is 2×10^{-5}/reactor-year, the

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*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 extremes" 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 upper 95% confidence limit is 7.5×10^{-5}/reactor-year, and the lower 5% confidence limit is 2.2×10^{-7}/reactor-year.

We note that the mean value of the core vulnerable frequency due to flooding is about 5 times as large as the estimate obtained by LILCO. The discrepancy is mainly due to our use of higher flood initiator-event frequencies and different approaches (Markov models and time-phased event trees).

5.0 Summary/Conclusion

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

In contrast LILCO found that core vulnerable frequency initiated by flooding is about 4×10^{-6}/reactor-year; the contribution to this value from maintenance-induced flooding is 1.5×10^{-6}/reactor-year, and from pipe-break-induced flooding is 2.4×10^{-6}/reactor-year. Our estimates are predicated upon the assumption that the alarm-response procedures are adequate. However, we identified some potential deficiencies in these procedures and the core vulnerable frequency may be higher than that estimated unless the procedures are corrected.

References

1. SAI-372-83-PA-01, "Final Report - Probabilistic Risk Assessment Shoreham Nuclear Power Station," Science Applications, Incorporated, June 24, 1983.
2. Letter from J. L. Smith (LILCO) to H. R. Denton (NRC), "Evaluation of Internal Flooding, Shoreham Nuclear Power Station Unit 1," December 2, 1982.
3. WASH-1400, "Reactor Safety Study," October 1975.
4. Memorandum dated November 16, 1982 from S. H. Hanauer to D. G. Eisenhut, "Shoreham PRA - Review of Suffolk County Consultants - Staff's Preliminary Review."
5. Letter dated September 24, 1982 from R. J. Budnitz (FRA) to H. R. Denton (NRC), "Review and Critique of Previous Probabilistic Accident Assessments for the Shoreham Nuclear Power Station."
6. 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.
7. NUREG/CR-1205, Rev. 1, "Data Summaries of Licensee Event Reports of Pumps at U.S. Commercial Nuclear Power Plants: January 1, 1972 to September 30, 1980," U.S. Nuclear Regulatory Commission, January 1982.
8. NUREG/CR-1363, W. H. Hubble, C. Miller, "Data Summaries of Licensee Event Reports of Valves at U.S. Commercial Nuclear Power Plants," June 1980.
9. NUREG/CR-1278, A. D. Swain and H. E. Guttmann, "Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications," April 1980.

A Preliminary Review

of the Sequences Following a Release

of Excessive water in Elevation 8 of the Reactor Building

in the Shoreham Nuclear Power Station

K. Shiu
Y. H. Sun
E. Anavim
I. A. Papazoglou

March 16, 1984

Risk Evaluation Group
Department of Nuclear Energy
Brookhaven National Laboratory

1.0 INTRODUCTION

At 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 builcing surrounding the MARK II containment structure. Water leakage from equipment in the reactor builiding will drain to Elevation 8 (the lowest level of the RB) via openings and stairwells since there is no structural separation between safety systems. A flooding of the Elevation 8 compartment may disable the ECCS because the ECCS pumps are installed in the Elevation 8 compartment.

The SNPS PRA has included the 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 detail 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 equipments. 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 condition 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 a abnormal system parameter, especially under a multiple alarm situation (such as a turbine trip).

BNL's revised event trees and the preliminary quantitative evaluation of core melt risk due to the RB flooding event 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, Secstion 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 included 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.

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"levels 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 ,ich 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 precursors 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 2.1.1 summarizes the information in a matrix form. Each row of the matrix depicts one of the 17 types of internal

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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 nonpressurized part of the piping.

2.2.1 Maintenance-induced Flood Initiators

The frequency of an initiator of type one was calculated by estimating the frequency of maintenance of various components from 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.

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Motor Driven Pumps

- Leakage/rupture: 6 events/6,777,627 hrs. = $8.9x10^{-7}$/hr.

- Does not start, loss of function, and does not continue to run: (5+4+6) events (13,644 demands = $1.1x10^{-3}$/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

($8.9x10^{-7}$ failure/hr) (24 hr/day) (365 day/yr) + ($1.1x10^{-3}$/demand) (12 demands/yr) = $2.0x10^{-2}$ 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 the two are linked as a pair to the RHR Heat Exchanger System. There is only one turbine driven pump associated with HPCI and RCIC Systems. 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 losing the isolation of a component under maintenance and following that, 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 (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 (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.

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 6C3,500 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.

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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	6350 (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

	SYSTEM EVENT TREE ENTRY CONDITION FREQUENCY (Per Rx Yr)					
INITIATOR	H-O	H-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	5
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 RBCLW HX) (Motor Driven)	0.042	TFL5

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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 (G-14) 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 $\bar{T}_{FL6}$	CST/SUPP	2	0	1	0	76/1/14	3.5E-5
CS Discharge $\bar{T}_{FL7}$	SUPP	4	0	2	0	128/2/12	6.9E-5
LPCI Discharge $\bar{T}_{FL8}$	SUPP	14	4	4	0	240/6/16	2.5E-4
Service Water $\bar{T}_{FL9}$	Service Water	4	4	4	0	715/9/10-20	1.4E-4
WFPS $\bar{T}_{FL10}$	WFPS	1				157/2/6-8	1.1E-5
RCIC** Suction $\bar{T}_{FL11}$	CST	1	1	1	1	70/1/6	3.5E-5
HPCI** Suction $\bar{T}_{FL12}$, $\bar{T}_{FL13}$	CST**	1	1	1	1	87/1/16	3.5E-5
CS** Suction $\bar{T}_{FL14}$, $\bar{T}_{FL15}$	CST*	2	2		2	120/2/12	4.9E-5
LPCI** Suction $\bar{T}_{FL16}$, $\bar{T}_{FL17}$	SUPP	4			4	120/2/20	5.2E-5

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

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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	$P(A_A(X))$	$P(A_M(X))$
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

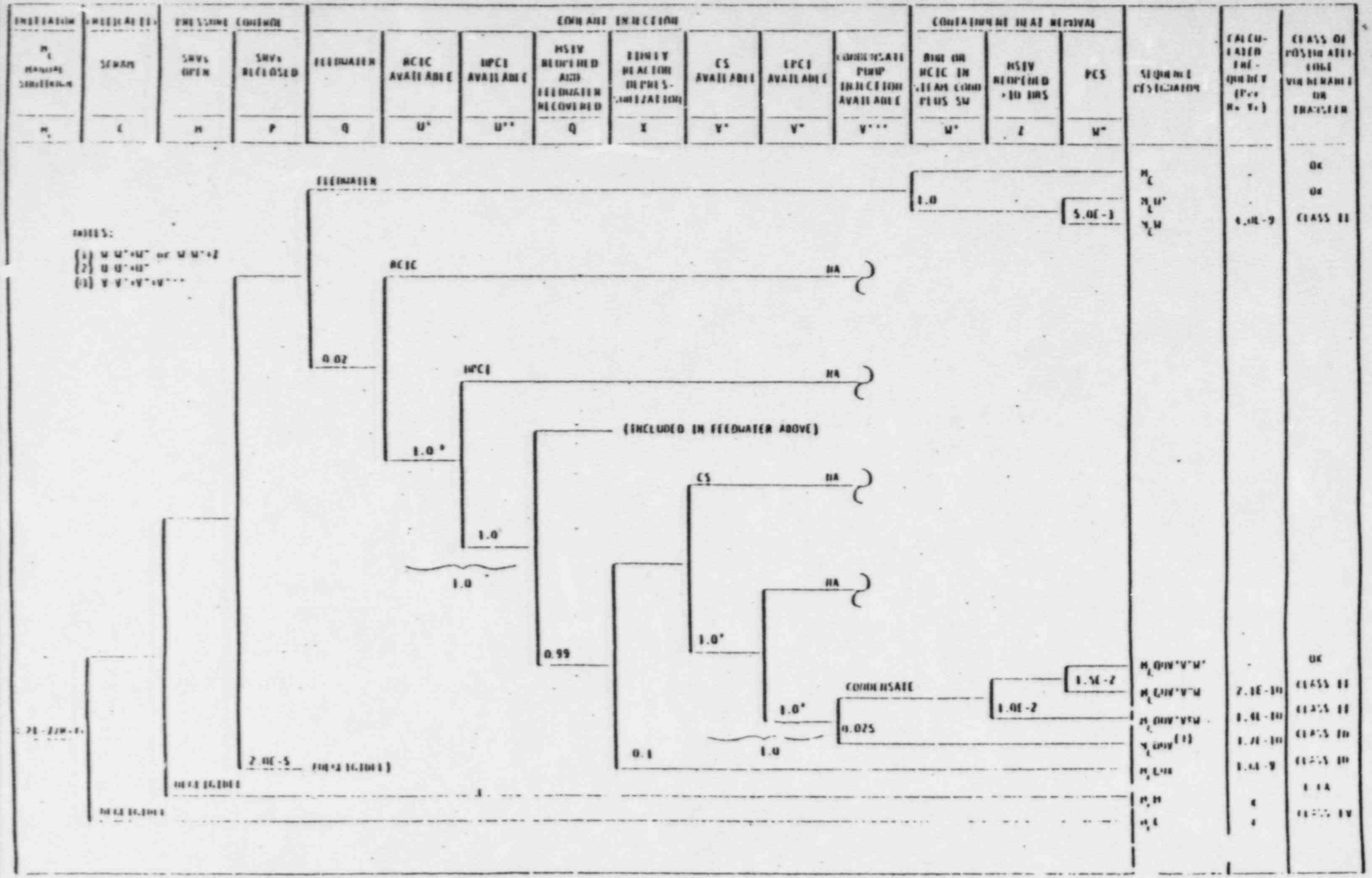


Figure 2.1.1 System Event Tree for Manual Shutdowns With Greater Than 3'-10" of Water in the Reactor Building (Source = CST).

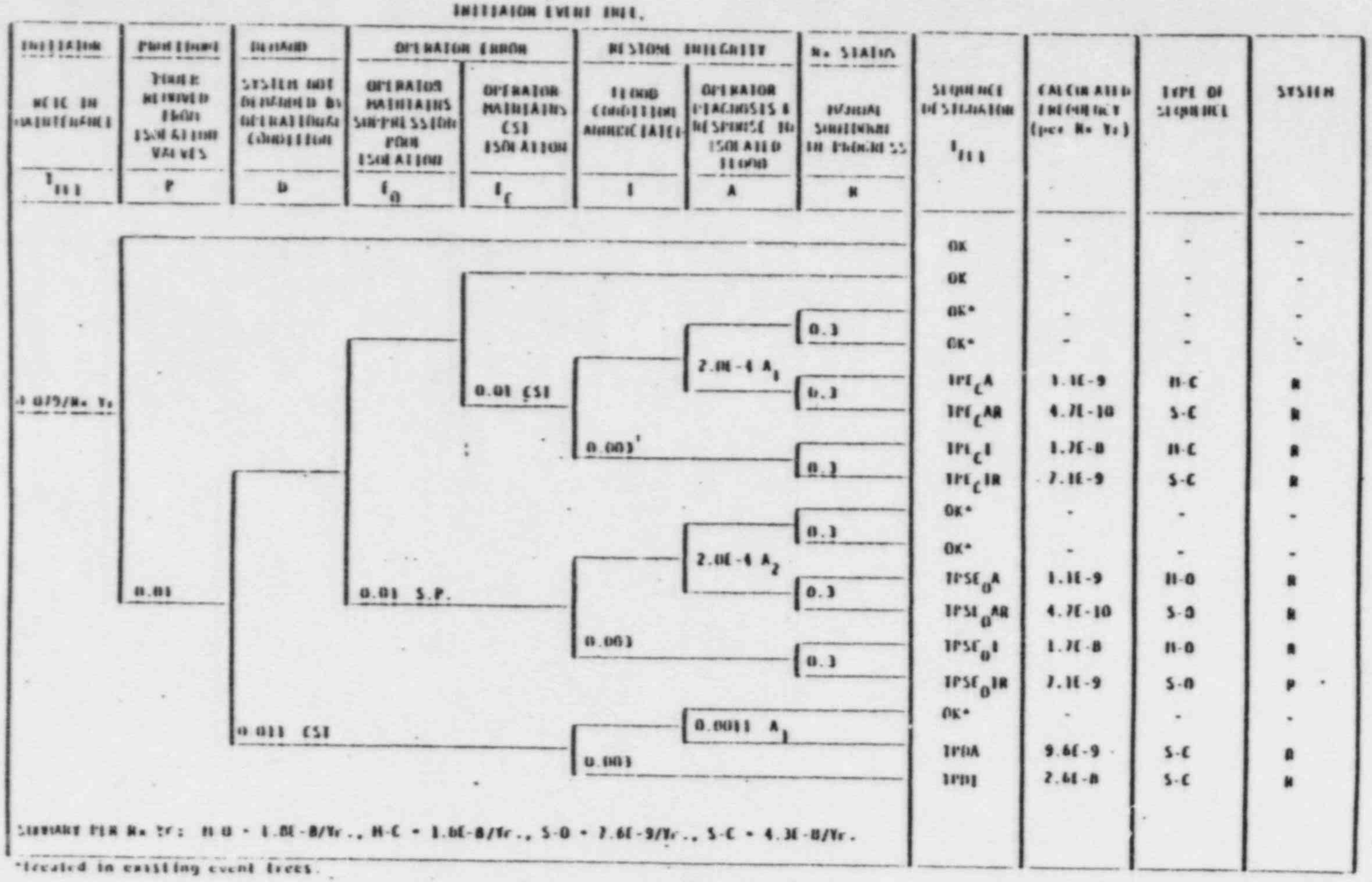


Figure 2.3.1 T_{IL1}: Initiator Event Tree for Postulated Flooding Sequences Initiated During RCIC Maintenance

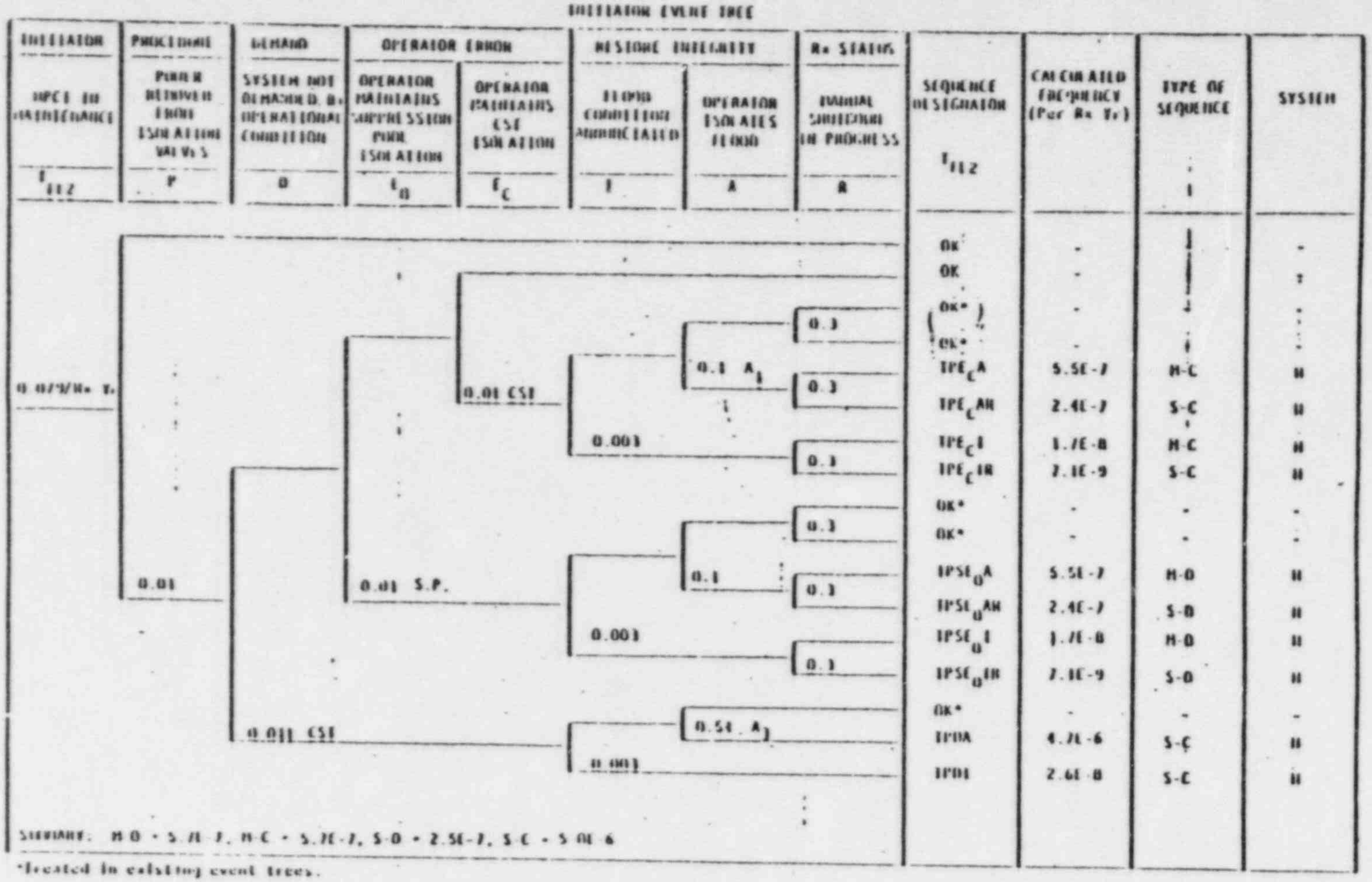
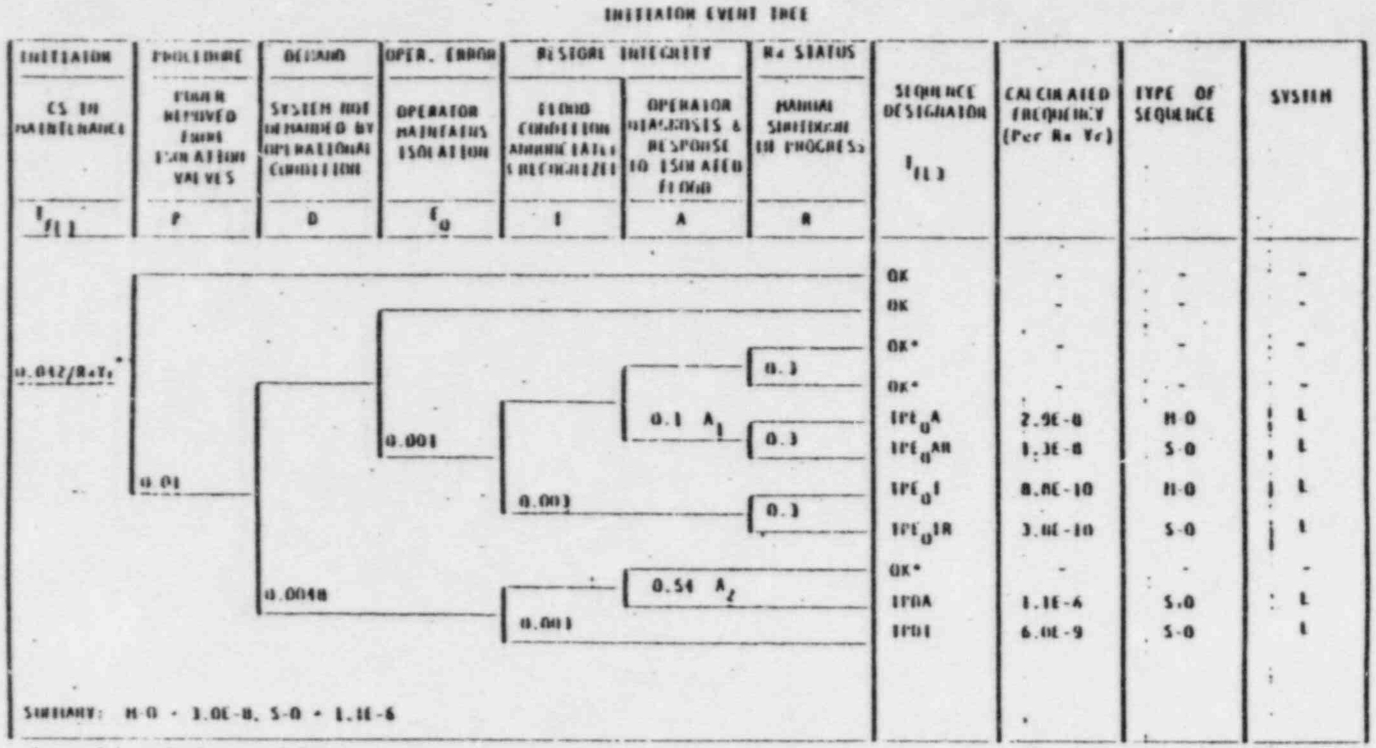
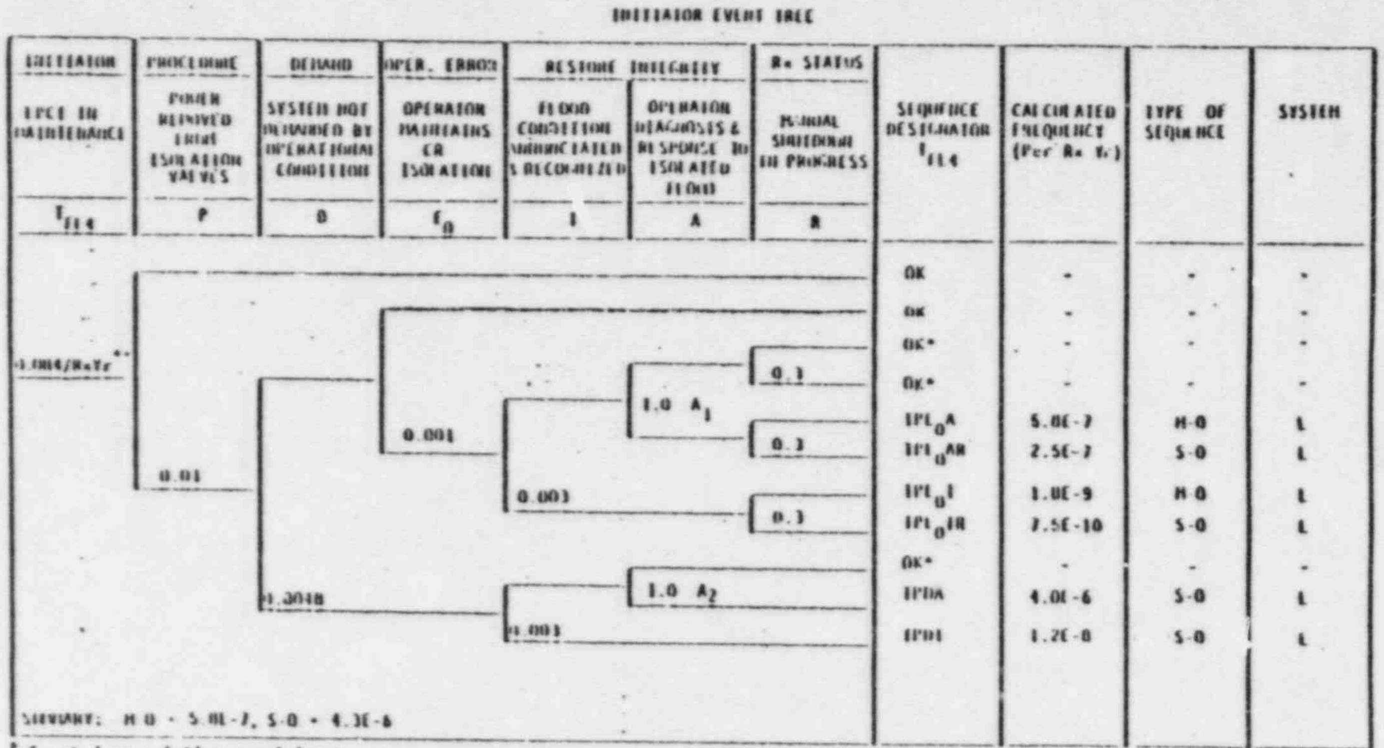


Figure 2.3.2 T_{FL2} - Initiator Event Tree for Postulated Flooding Sequences Initiated by an Error During HPCI Major Maintenance



* 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

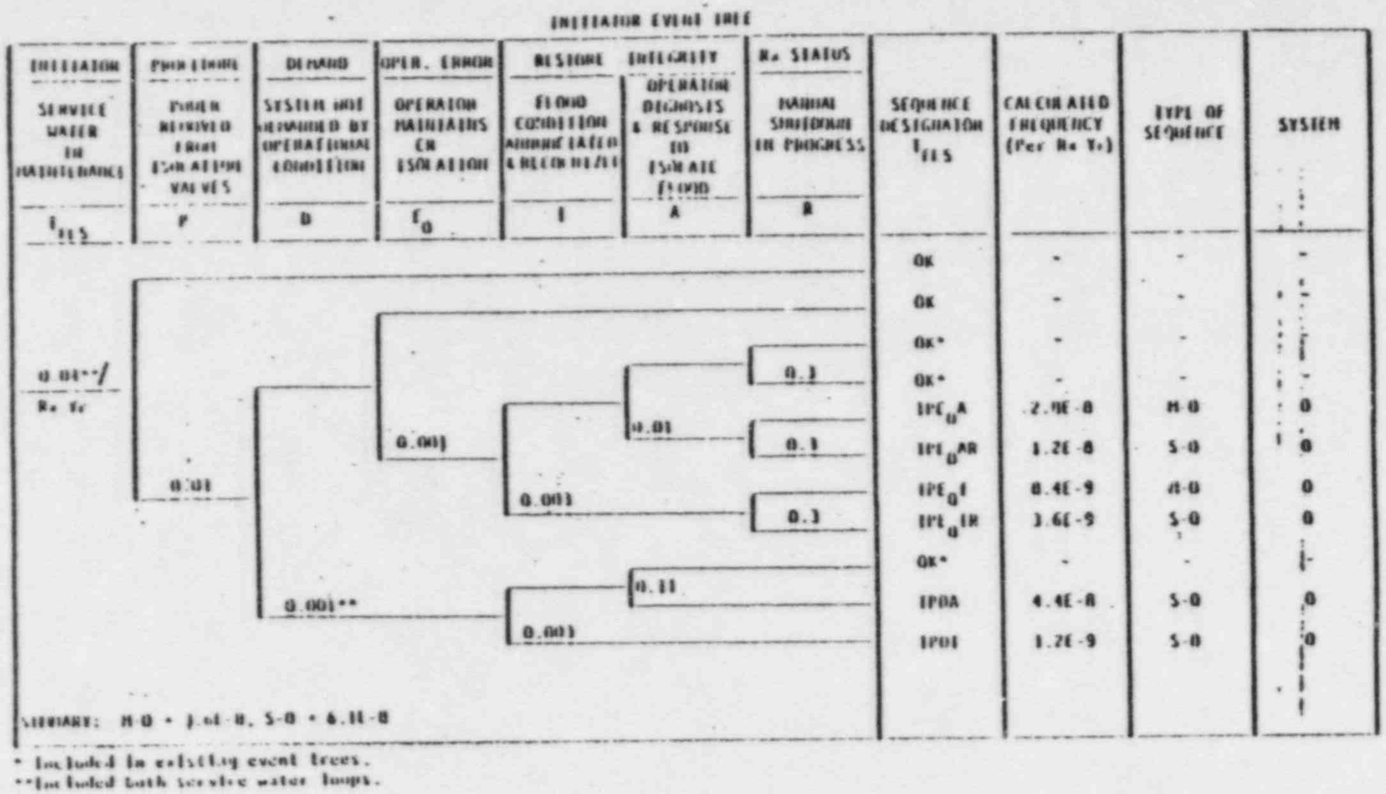
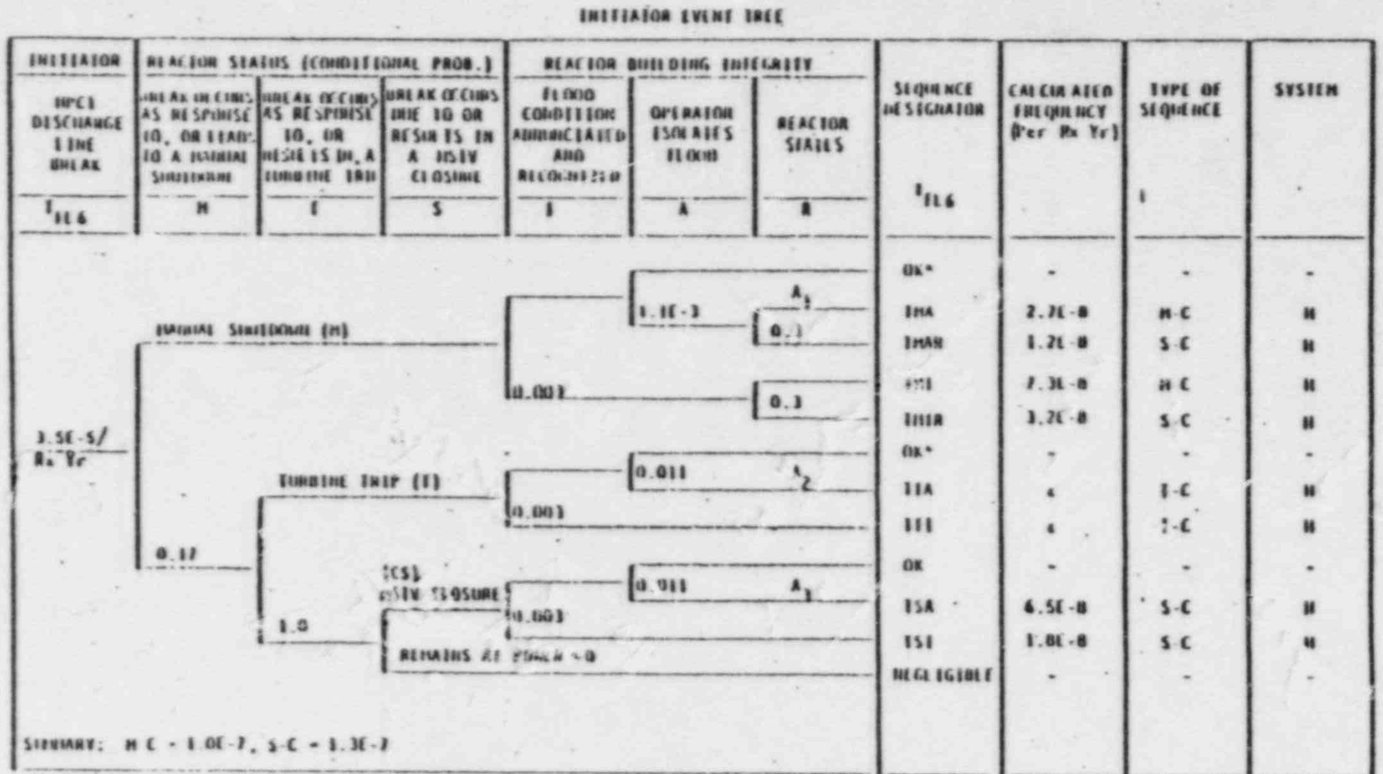


Figure 2.3.5 T_{FLS} - Initiator Event Tree for Postulated Flooding Sequences Initiated by an Error During Service Water Major Maintenance (i.e., Heat Exchangers)



*Included in the previously evaluated event tree.

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

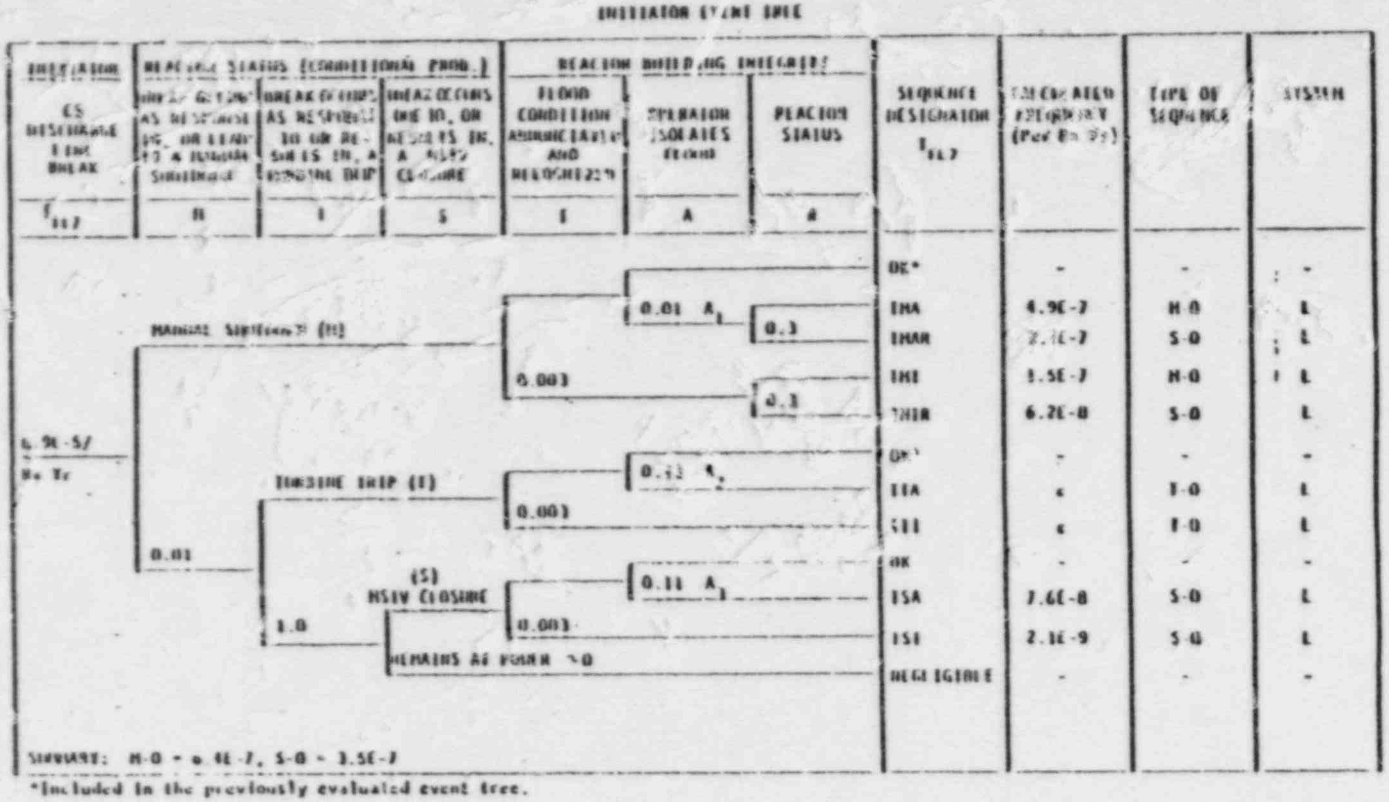
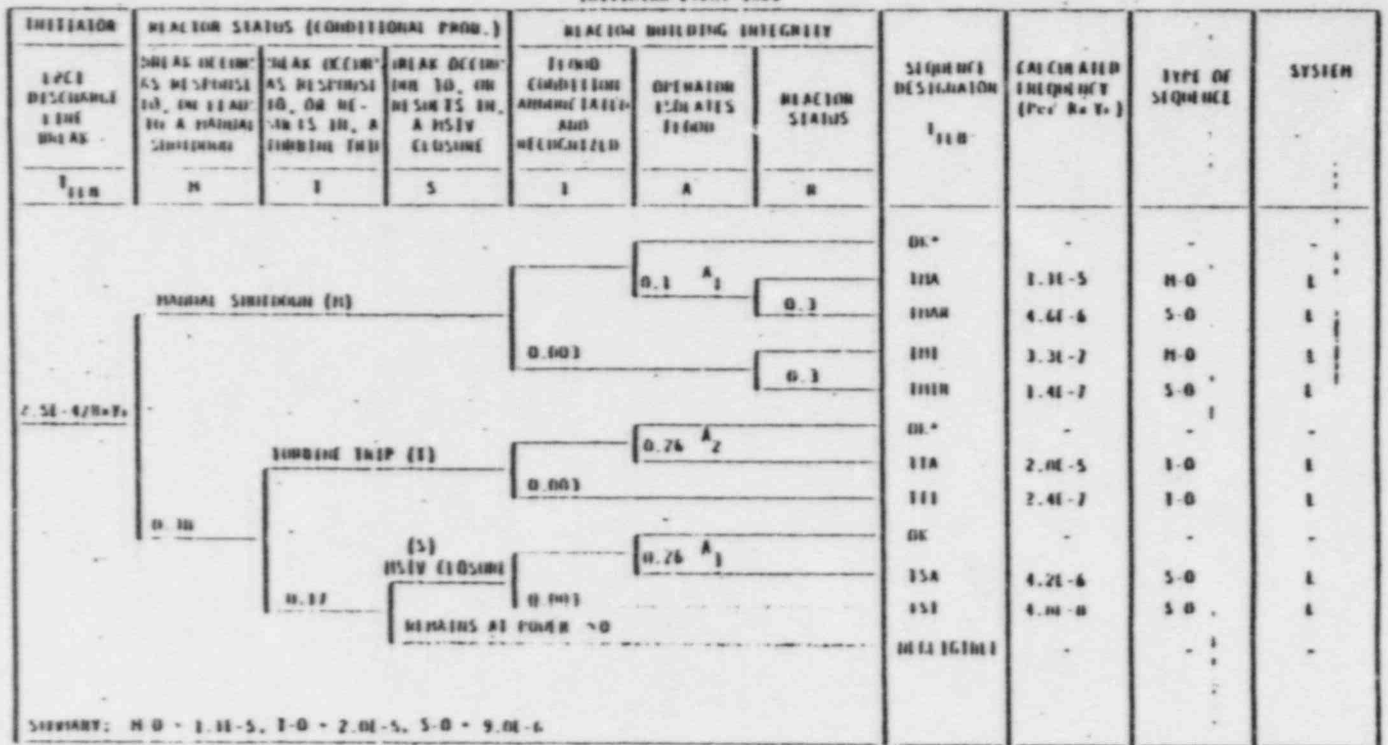


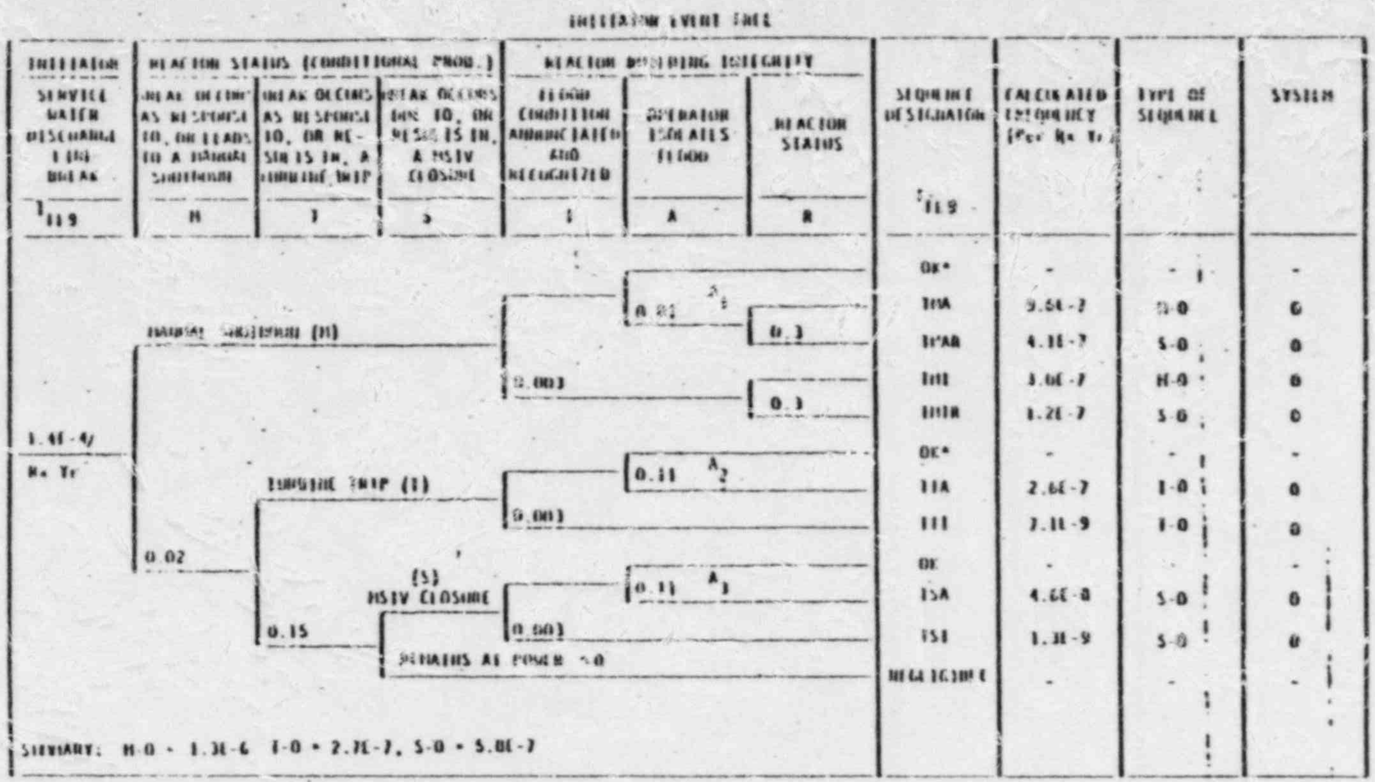
Figure 2.3.7 Initiator Event Tree for Postulated Flooding Sequences Initiated by a CS Discharge Pipe Break

INITIATOR EVENT TREE



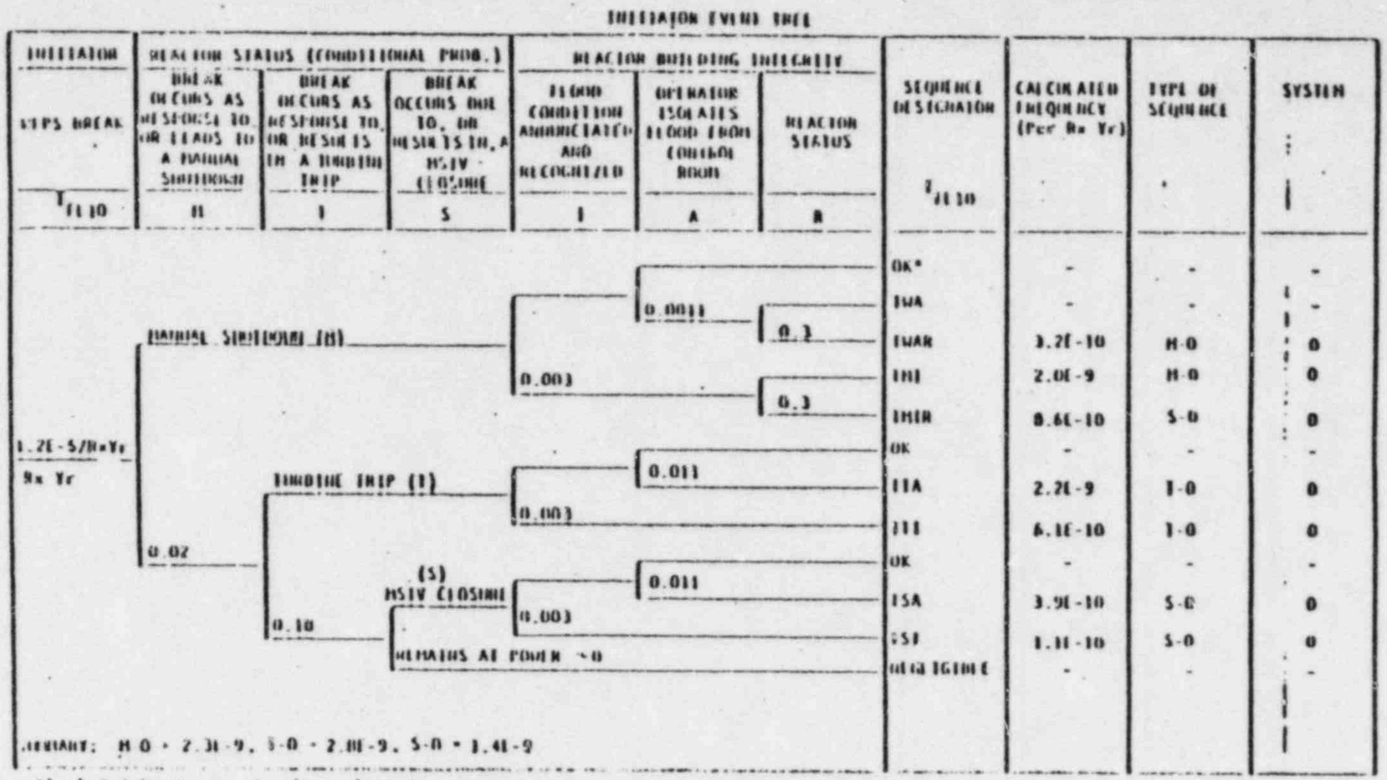
*Included in the previously evaluated event trees.

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



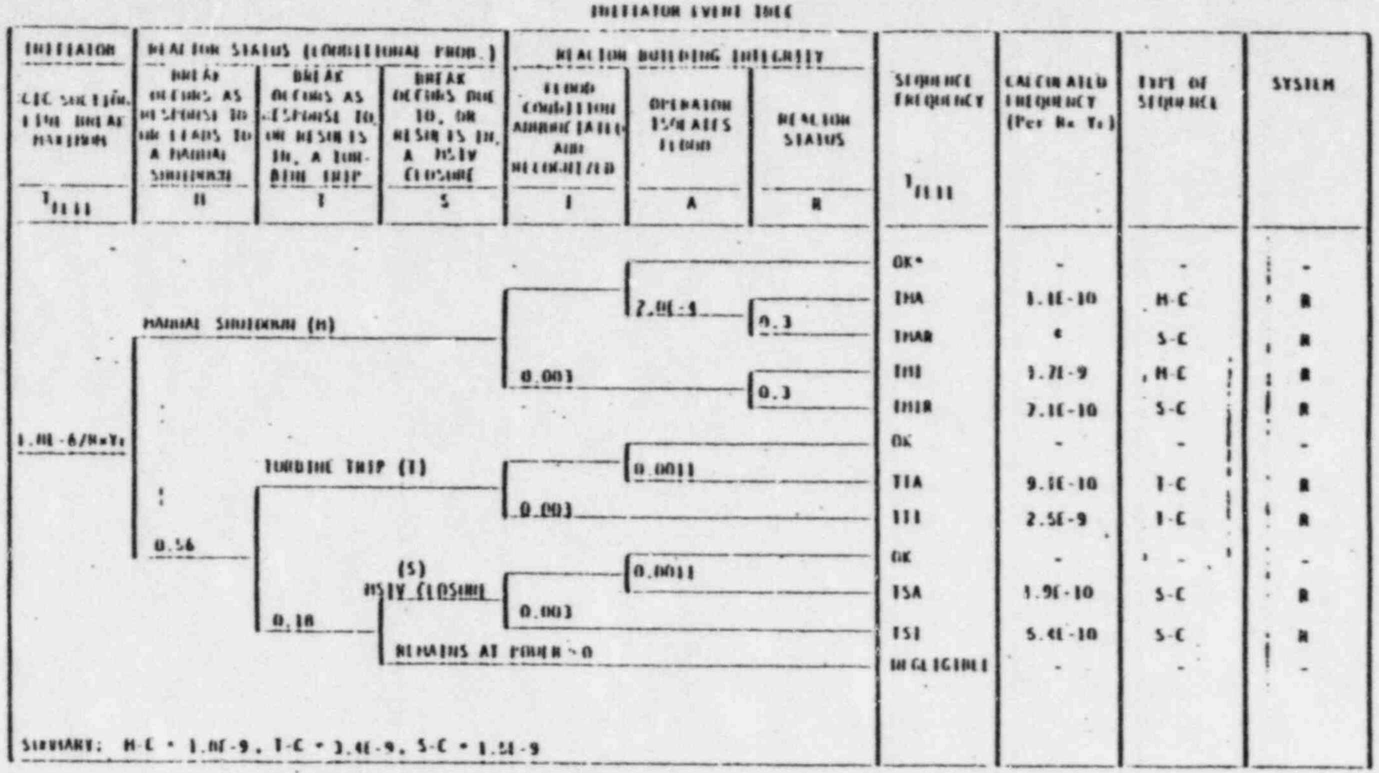
*Included in the previously evaluated event trees.

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



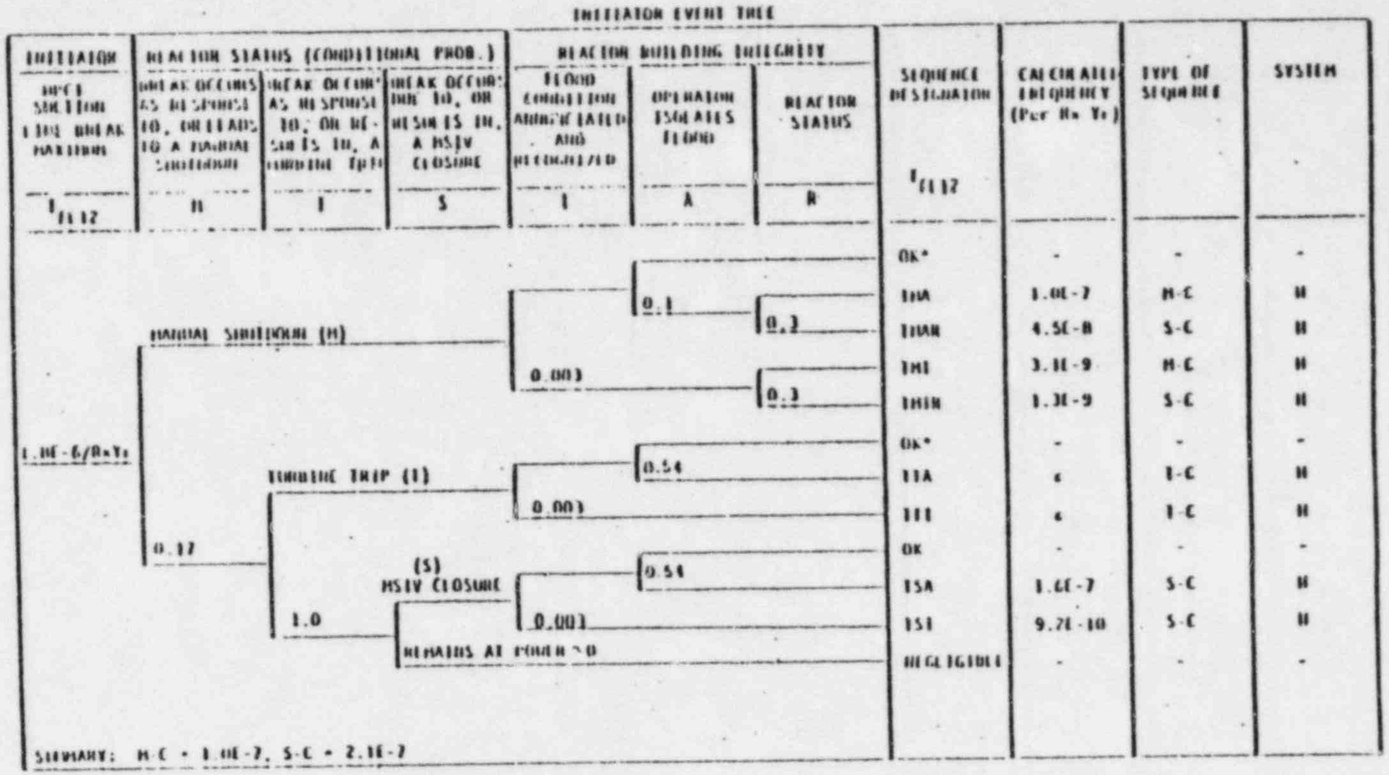
*Included in the previously evaluated event trees.

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



*Included in the previously evaluated event trees.

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



*Included in the previously evaluated event trees.

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

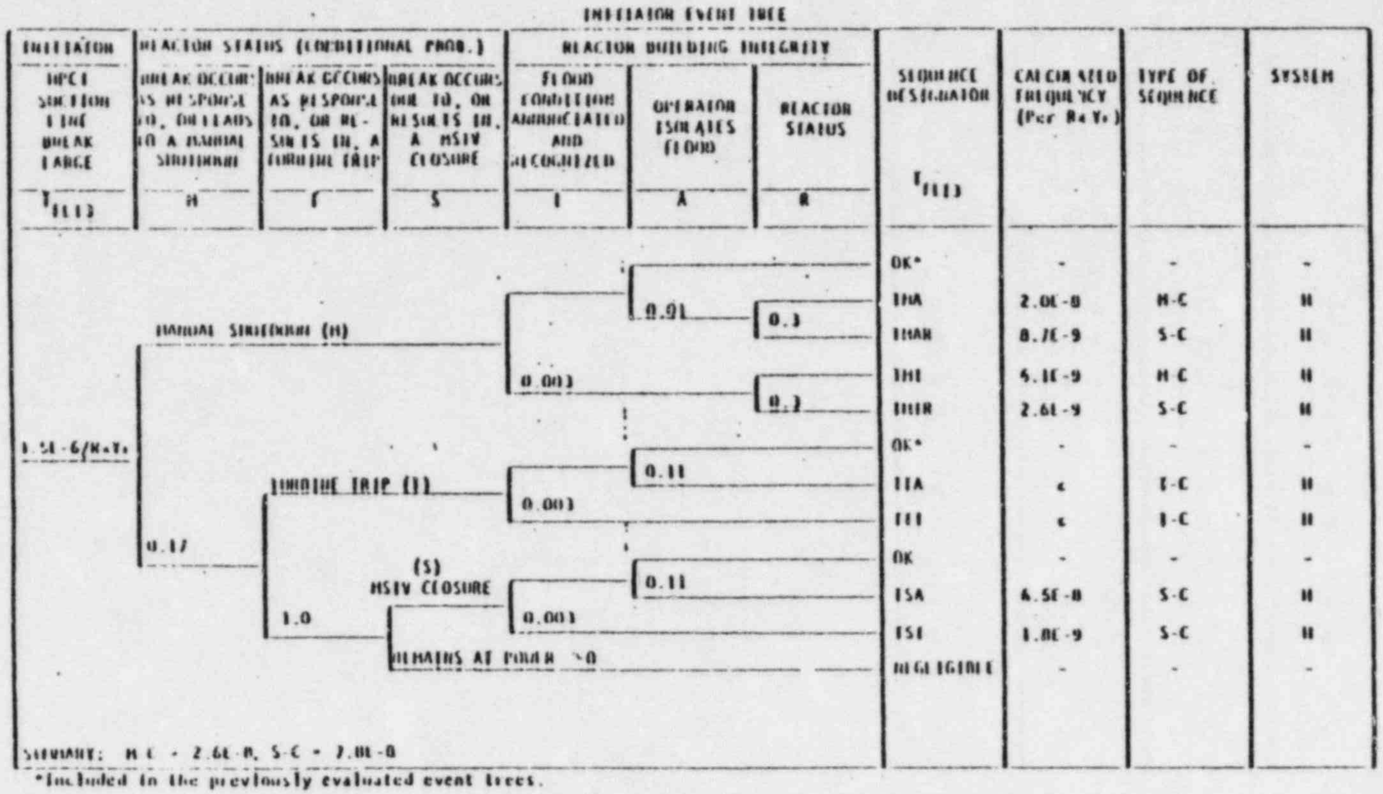
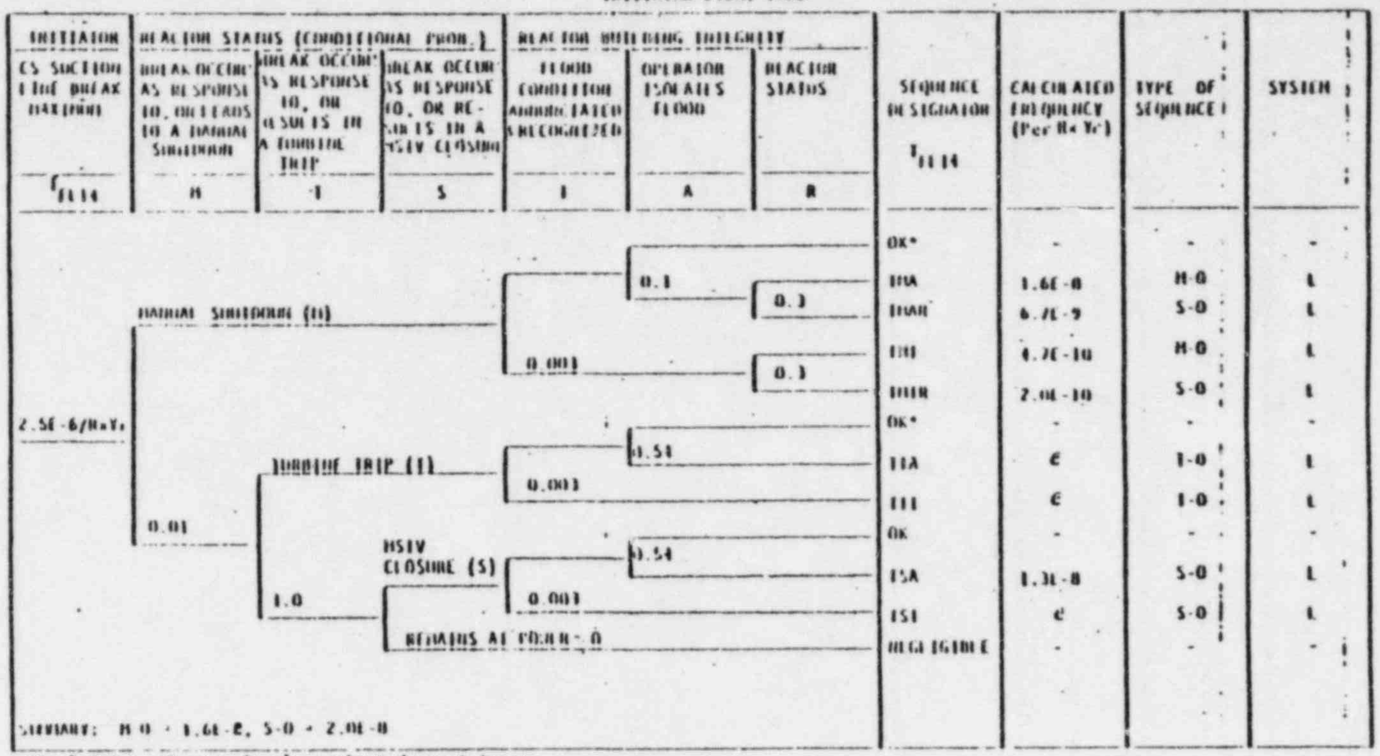


Figure 2.3.13 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Large HPCI Suction Line Break

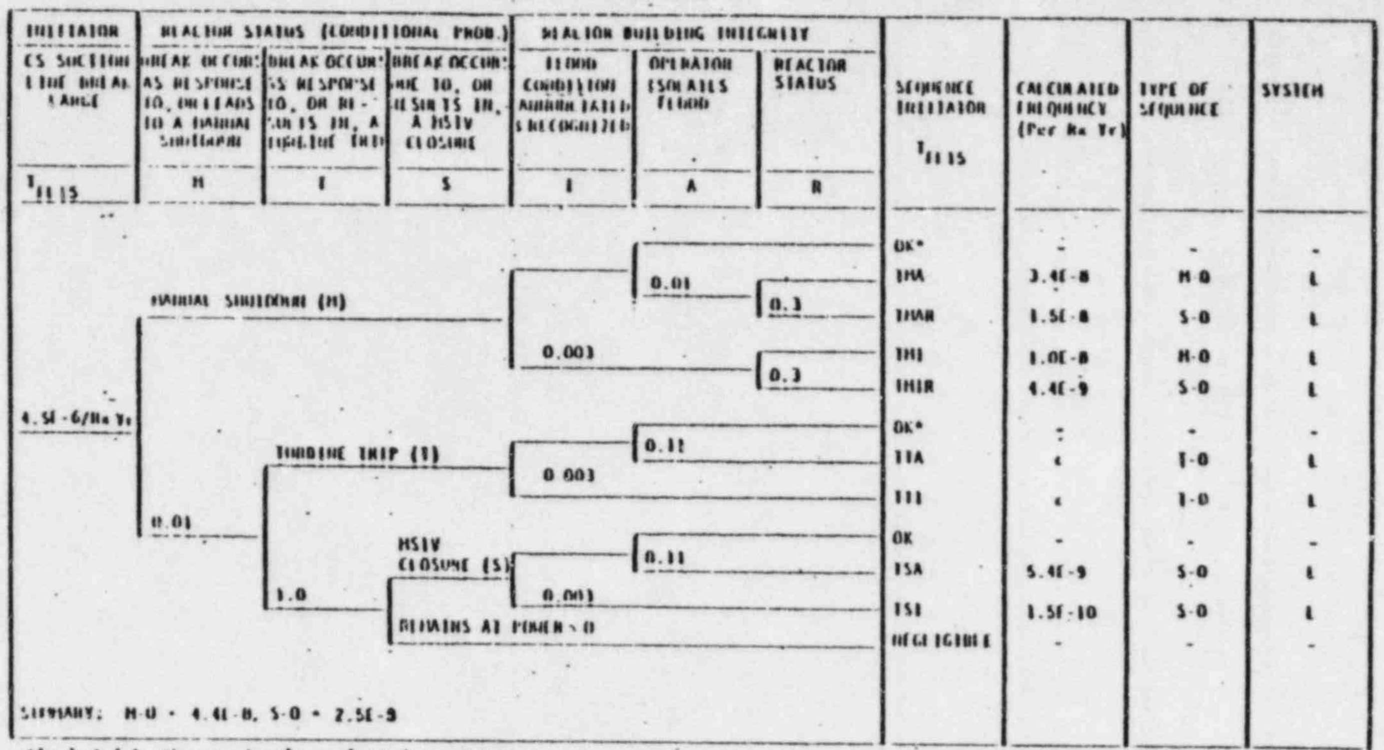
INITIATOR EVENT TREE



*Included in the previously evaluated event trees.

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

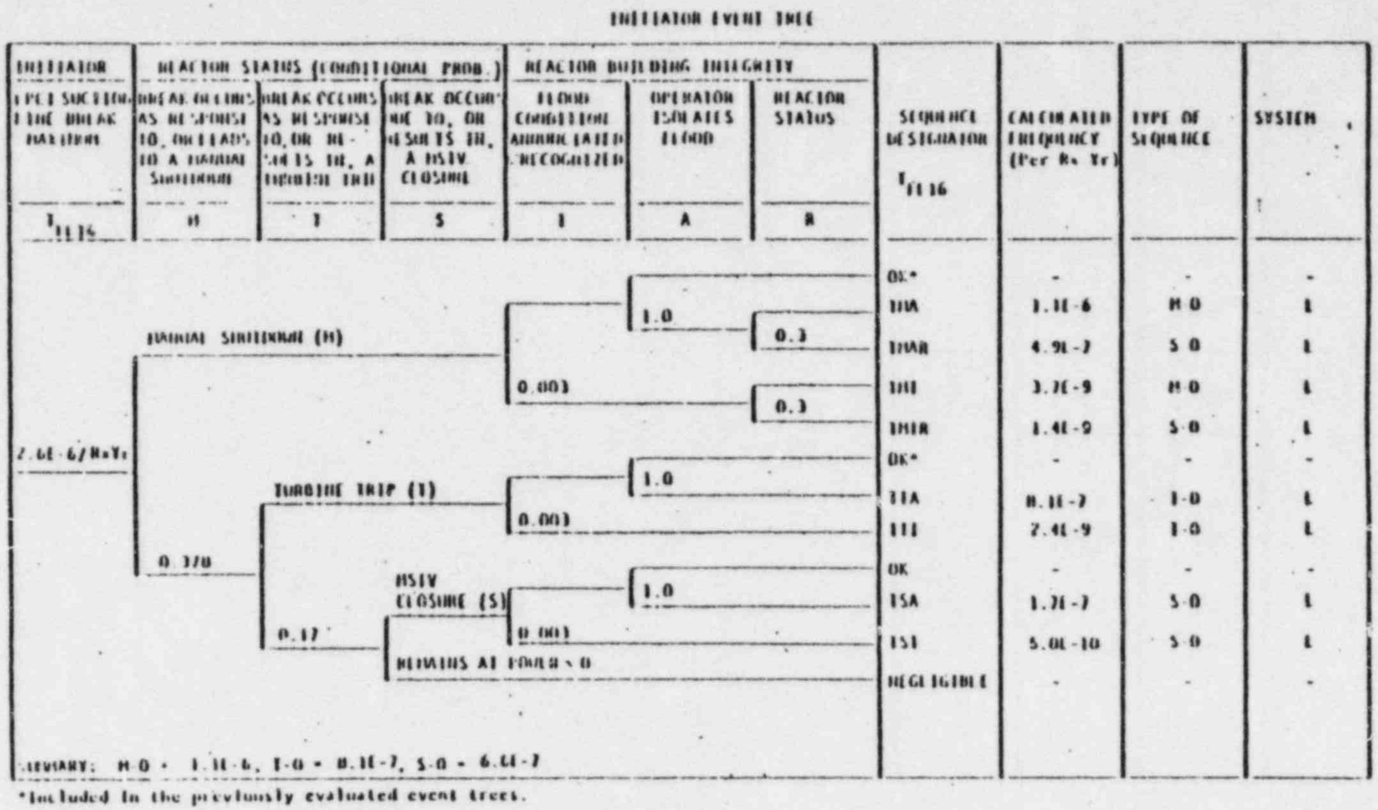


Figure 2.3.16 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Maximum LPCI Suction Line Break

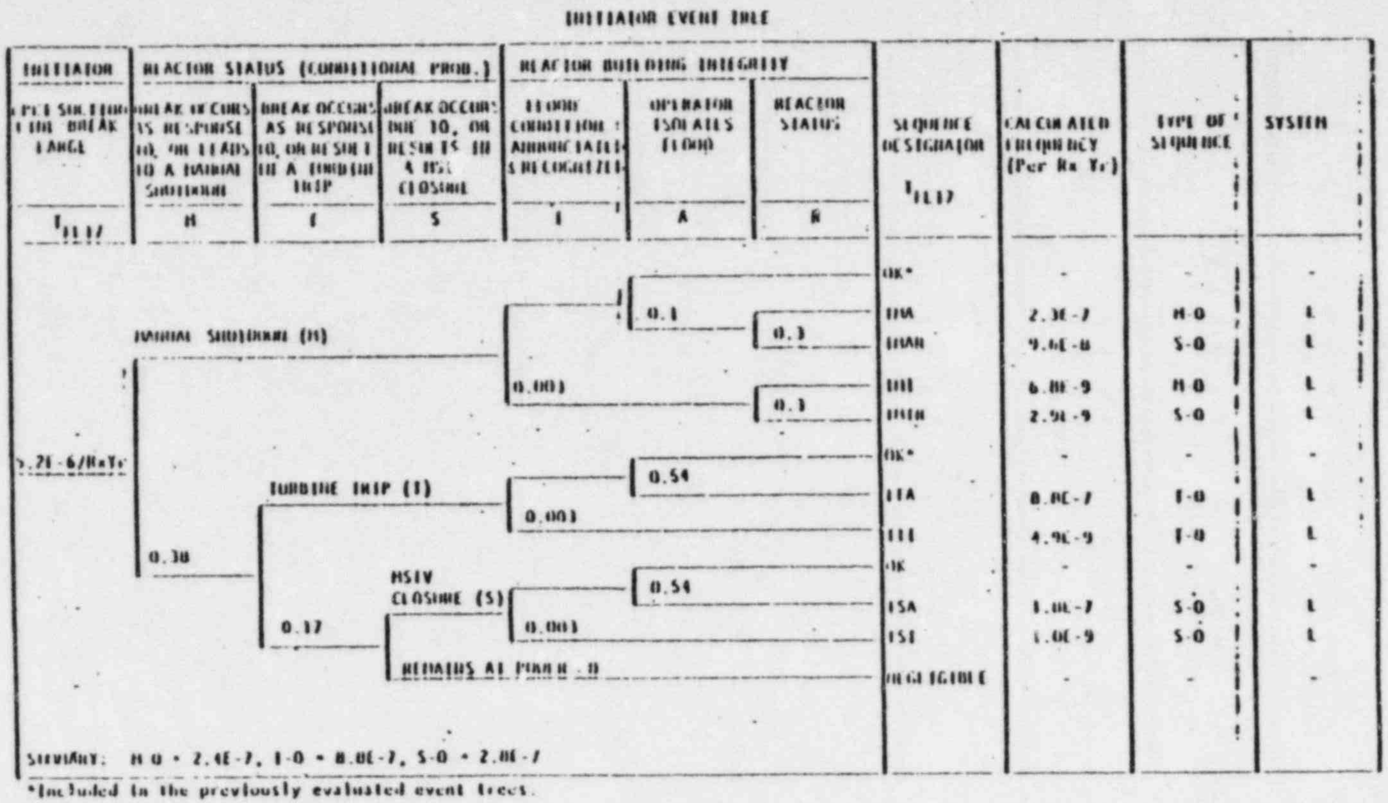


Figure 2.3.17 Initiator Event Tree for Postulated Flooding Sequences Initiated by a Large LPCI Suction Line Break

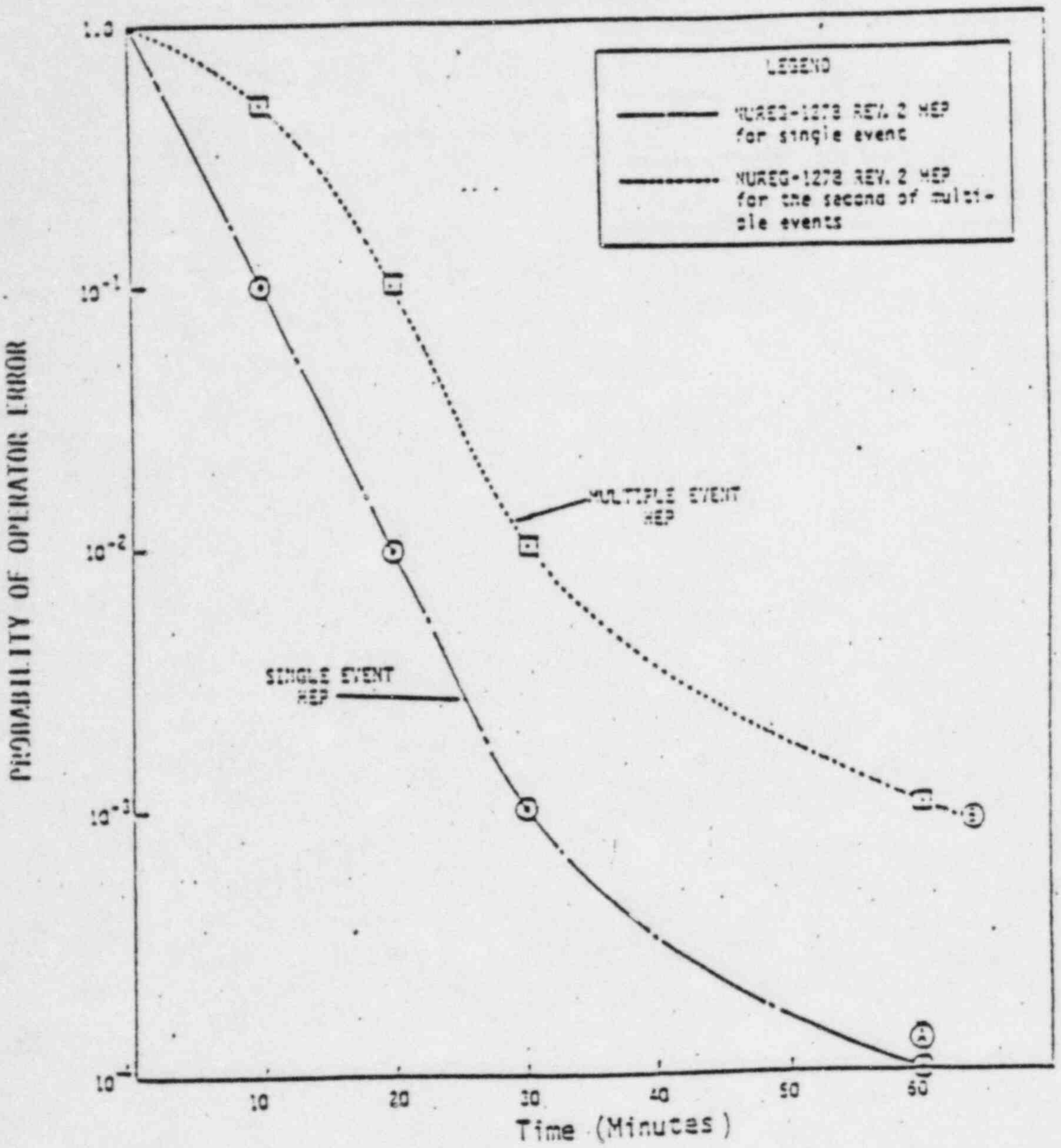


Figure 2.3.18 Comparison of the HEPs Associated with Operator Actions for Singular Events and Coincident Multiple Events

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 requires dismantling of the component and one of the isolation valves opens inadvertently while the component is 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).

viii) While in state 3', an actual demand for the component (following a transient initiator) or an inadvertent operation of the corresponding switch in the control room will result into the opening of one of the isolation valves. This event is modeled by a transition of the componet from state 3' to state 5. The reactor transients and the operators errors are assumed to occur with constant rates. λ_D and λ_0, respectively.

Quantification of the Markovican model and the determination of the probability that the component will occupy state 5 at the end of one year yields the probability that there will be a maintenance-induced flood by that particular component.

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. 4). The new data are summarized in Table 3.3.1.

Maximum likelihood estimators for the failure rates

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

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

and

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

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

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

and

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

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

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

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 plumps, 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

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

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Quantification of the Markovian model with the numerical values of the parameters mentioned above yield the probabilities per year for the various maintenance induced floods. The results are tabulated in Table 3.1.2. Additional assumptions are that the Core Spray System consists of two motor driven pumps, the LPCI consists of four motor driven pumps and that RBCLW 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, RBCLWHX) 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

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$$P_i(t) = F \frac{\lambda_i \ \lambda_R}{\lambda - \lambda_R} \quad (1-e^{-\lambda} \quad)/\lambda_R - (1-e^{-\lambda t})/\lambda \qquad (1)$$

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

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

Quantification

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

$$\lambda_R = \quad \lambda' + n_v\lambda_v + n_p\lambda_p \qquad (3)$$

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

A search of the LER, has indicated that at least one pipe rupture (weld failure) has occurred in the ECCS piping in the 215 accumulated BWR year. (See Ref. 5).

This provides a maximum likelihood estimator for the rupture failure rate of (1/215y = 5.31×10^{-7}/1hr). 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

$$\lambda = \left(\frac{\ell}{L} \right) \times 2.7\times10^{-8}/\text{hr} \qquad (4)$$

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.

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	13,644	6,777,627	6	5	4	6
Turbine Driven	1,820	868,033	-	1	6	5

Table 3.1.2 Frequency of Maintenance - Induced Flood Precursors

System	Initiator Event Trees	Probability per Year
	TFL1 P.D	1.05×10^{-4}
1. RCIC	TFL1 P.E_0	2.10×10^{-5}
	TFL1 P.E_C	2.10×10^{-5}
	TFL2 P.D	1.05×10^{-4}
2. HPLIC	TFL2 P.E_0	2.10×10^{-5}
	TFL2 P.E_C	2.10×10^{-5}
3. Core Spray	TFL3 P.D	1.89×10^{-5}
(2 motor driven pumps)	TFL3 P.E_0	1.87×10^{-6}
4. LPCI	TFL4 P.D	3.78×10^{-5}
(4 motor driven)	TFL4 P.E_0	3.74×10^{-6}
5. Service Water	TFL5 P.D	1.89×10^{-5}
(RHR or RB(LW HX)	TFL4 P.E_0	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)	1.57(-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)	2.86(-8)	0	3.2(-8)	6.5(-5)	7.3(-5)	6.2(-5)
TFL9	1.1(-8)	2.34(-8)	6.0(-10)	1.29(-8)	2.6(-5)	2.9(-5)	2.5(-5)
TFL10	2.4(-9)	1.30(-9)	0	3.7(-9)	7.5(-6)	8.4(-6)	7.2(-6)
TFL11	1.1(-9)	9.10(-9)	1.5(-10)	1.04(-8)	2.1(-5)	2.4(-5)	2.0(-5)
TFL12	1.4(-9)	3.90(-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)	5.20(-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)	5.20(-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)

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 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

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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 (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.

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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.

Table 3.3.1 enumerates the vital equipment that has been identified in the Shoreham analysis. The components are presented with those located at the lowest elevation first. It can be seen that at the 1' level, both the RCIC and HPCI vacuum pumps and condensate pumps are expected to be disabled. However, it is judged that their failures do not lead to the failure of the respective high pressure systems. Similar arguments apply to the loop level pumps of the low pressure core spray, HPCI and the RCIC systems as well. At approximately 2', instrumentation for both high pressure injection systems are submerged and hence resulting in failure of both systems. At 3'-10" instrumentation for both LPCS and RHR is submerged leading to the failure of those low pressure systems. In the Shoreham analysis the critical height of 3'-10" is selected. However, since both HPCI and RCIC have failed at about 2' level, these scenarios with termination of the flood prior to 3'-10" may not contribute an insignificant amount to the core vulnerable frequency. In the BNL revised event trees, a time-phased approach is used to include the contribution from flooding below the 3'-10" level.

Another area of concern stems from the treatment of propagation of failures in the Shoreham analysis. As noted in Table 3.3.1, at the 1' level, 4-480V pumps are expected to experience electrical shorts. The Shoreham analysis did not investigate any cascading failure which may result from the electrical shorts. BNL reviewed the electrical drawings and elementary drawings for some of the systems. It appears that for each pump there is only one electrical breaker which separates it from the rest of the loads in the same motor control center (MCC). Random failure of this breaker to open could result in the propagation of the short circuit fault upstream to the MCC, other MCCs and the load center. BNL's review of the electrical diagrams indicates that failure of the breaker to open will result in tripping the breaker at the load center. Discussions with Shoreham engineers suggested that there may possibly be an additional breaker per pump that is in series with the first breaker. However, this was not confirmed by BNL. In the BNL revised event trees, only one breaker is assumed and its failure is modeled explicitly.

BNL did not review the spraying effects due to water cascades from higher elevations.

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 I. 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, in which the various mitigation systems are considered. 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 not 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 liklihood 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, BNL time-phased event tree and the modified human response to arrest flood, preliminary quantitative results are obtained. 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.

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 revaluated 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 two 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. Part B of Table 4.1 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 $3x10^{-6}$ or about 18%. The major increase in core vulnerable frequency in the BNL analysis is attributable to the increase in flood precursor frequencies.

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