Safety Evaluation Report
related to the operation of Limerick Generating Station, Units 1 and 2

Docket Nos. 50-352 and 50-353

Philadelphia Electric Company

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

October 1984

UNITED STATES NUCLEAR REGULATORY COMMISSION

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NUREG-0991
Supplement No. 2

Safety Evaluation Report
related to the operation of Limerick Generating Station, Units 1 and 2

Docket Nos. 50-352 and 50-353

Philadelphia Electric Company

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Office of Nuclear Reactor Regulation

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ABSTRACT

In August 1983 the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0991) regarding the application of the Philadelphia Electric Company (the applicant) for licenses to operate the Limerick Generating Station, Units 1 and 2, located on a site in Montgomery and Chester Counties, Pennsylvania.

Supplement 1 to NUREG-0991 was issued in December 1983 and addressed several outstanding issues. Supplement 1 also included the interim report of the Advisory Committee on Reactor Safeguards and the staff's initial response to the comments made in the report.

This supplement to NUREG-0991 addresses further issues that require resolution and closes them out.

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

In August 1983, the Nuclear Regulatory Commission staff (hereinafter referred to as the NRC staff) issued its Safety Evaluation Report (NUREG-0991) regarding the application by the Philadelphia Electric Company (hereinafter referred to as the applicant) for licenses to operate the Limerick Generating Station, Units 1 and 2 (hereinafter referred to as Limerick or the facility), Docket Nos. 50-352 and 50-353. The Safety Evaluation Report was supplemented by Supplement No. 1 which documented the resolution of several outstanding issues in further support of the licensing activities. This report is Supplement No. 2 to the Safety Evaluation Report.

The purpose of this supplement is to further update the Safety Evaluation Report by providing (1) an evaluation of additional information submitted by the applicant on unresolved issues since the issuance of Supplement No. 1 to the Safety Evaluation Report, and (2) an evaluation of additional information for those sections of the Safety Evaluation Report where further discussion or changes are in order.

Each of the following sections of this supplement is numbered the same as the corresponding section of the Safety Evaluation Report and Supplement No. 1. Each section is supplementary to and not in lieu of the discussion in the Safety Evaluation Report and Supplement No. 1 unless otherwise noted.

Appendix A to this supplement is a continuation of the chronology of the staff's actions related to processing of the Limerick application.

This supplement to the Safety Evaluation Report was prepared by the NRC staff. The NRC members who were principal contributors to this report are identified in Appendix H.

1.8 Outstanding Issues

The SER identified certain outstanding issues. Supplement 1 to the SER reported the resolution of some of those issues and identified some additional unresolved issues. The list provided below updates the status of these unresolved issues. Issues previously reported closed (5, 8, 9, 10, 16, 17, 18, 19, 20) are not addressed. Fourteen items within the list have been closed in this supplement.

Issue	Section(s)	Status*
(1) emergency preparedness	2.3.3, 13.3	R
(2) tornado-missile effects on ultimate heat sink	3.5.2	R

*R - Resolution reported in SSER-3
Closed - Closed for purposes of issuance of the operating license.

Issue	Section(s)	Status*
(3) pipe breaks outside containment	3.6.1	Closed (SSER-2)
(4) feedwater isolation check valves	3.6.2	Closed (SSER-2)
(6) seismic/dynamic and environmental qualification of equipment	3.10, 3.11	R, Closed (SSER-2)
(7) inadequate core cooling	4.4.7, 7.5.2.1	Closed (SSER-2)
(11) manual initiation of safety systems	7.3.2.5	Closed (SSER-2)
(12) post-accident monitoring instrumentation	7.5.2.3	R
(13) multiple control systems failures and high-energy line breaks and consequential control system failures	7.7.2.1	Closed (SSER-2)
(14) 3-hour-fire-rated barriers for structural steel	9.5.1.4	Closed (SSER-2)
(15) electrical cable and cable tray protection	9.5.1.4.5	Closed (SSER-2)
(21) ATWS events (Generic Letter 83-28)	15.8	Closed (SSER-2)
(22) Q list	17	Closed (SSER-2)
(23) control room design review	18	R
(24) containment emergency sump reliability (USI A-43)	Appendix C	Closed (SSER-2)
(25) failure modes and consequences of cooling towers	19	R
(26) materials furnished by Ray Miller, Inc. and Tube-Line Corporation	Appendix K	Closed (SSER-2)
(27) control room ceiling	3.7.3.1	Closed (SSER-2)
(28) two-stage Target Rock Valves	3.9.3.4	R
(29) pipe clamps	3.9.7	R
(30) Hayward Tyler pumps	Appendix L	Closed (SSER-2)
(31) stress corrosion cracking monitoring program	5.2.3, 19	Closed (SSER-2)

1.9 Confirmatory Issues

The SER identified certain issues that have been essentially resolved to the staff's satisfaction but for which certain confirmatory information had not yet been developed. Supplement 1 reported the resolution to some of those issues and identified some additional confirmatory issues. The list provided below updates the status of these confirmatory issues. Issues previously reported closed (part of item 6, 7, 8) are not addressed. Fifty-three items within the list have been closed in this supplement.

Issue	Section(s)	Status*
(1) FSAR Tables 3.2-1 and 3.2-2 revisions	3.2.2	Closed (SSER-2)
(2) piping isometrics and pipe whip effects	3.6.2	Closed (SSER-2)
(3) startup test specification for BOP piping	3.9.2.1	Closed (SSER-2)
(4) reactor internals analysis documentation	3.9.2.4	Closed (SSER-2)

*R - Resolution reported in SSER-3
Closed - Closed for purposes of issuance of the operating license.

Issue	Section(s)	Status*
(5) loading combinations, design transients, and stress limits	3.9.3.1	R
(6) inservice testing of pumps and valves	3.9.6	R
(9) overheating of gadolinia fuel pellets	4.2.3.2(4)	R
(10) high burnup fission gas release	4.2.3.3(1)	Closed (SSER-2)
(11) loose-parts monitoring systems	4.4.6	Closed (SSER-2)
(12) preservice inspection program	5.2.4.3, 6.6.3	R R
(13) alternate shutdown cooling flow path	5.4.7	Closed (SSER-2)
(14) environmental qualification envelope for drywell	6.2.1.3	Closed (SSER-2)
(15) bulk-to-local pool temperature differences	6.2.1.7.3	Closed (SSER-2)
(16) capping vacuum breaker downcomer	6.2.1.7.3	Closed (SSER-2)
(17) Anderson-Greenwood vacuum breaker test program	6.2.1.7.3	Closed (SSER-2)
(18) applicability of Mark III concerns	6.2.1.8	Closed (SSER-2)
(19) procedures for isolating feedwater bypass lines	6.2.4.1	Closed (SSER-2)
(20) procedures for hydrogen recombiner operation	6.2.5	Closed (SSER-2)
(21) procedures for Type A leakage testing for hydrogen recombiner and combustible gas analyzer	6.2.5	Closed (SSER-2)
(22) fracture toughness of containment pressure boundary	6.2.7	R
(23) procedures for response to LOCA	6.3.5	Closed (SSER-2)
(24) plant-specific LOCA analysis	6.3.5, 15.9.4	Closed (SSER-2)
(25) test results for steam effects on core spray distribution	6.3.5	Closed (SSER-2)
(26) instrumentation setpoints	7.2.2.1	R
(27) failures in reactor vessel level sensing lines	7.2.2.2	Closed (SSER-2)
(28) isolation of circuits	7.2.2.9	Closed (SSER-2)
(29) APRM upscale trips	7.2.2.10	Closed (SSER-2)
(30) restart of HPCI and RCIC on low water level	7.3.2.4	R
(31) automatic switchover of RCIC	7.4.2.2	R
(32) rod sequence control system, rod worth minimizer, and the rod block monitor	7.7.2.2	Closed (SSER-2)
(33) capability for safe shutdown following loss of electrical power	7.4.2.1	Closed (SSER-2)
(34) remote shutdown system	7.4.2.3	R
(35) fire protection program	9.5.1.1.1	Closed (SSER-2)
(36) fire hazards analysis	9.5.1.1.2	Closed (SSER-2)
(37) administrative controls	9.5.1.2	Closed (SSER-2)
(38) fire brigade	9.5.1.3	Closed (SSER-2)

*R - Resolution reported in SSER-3
Closed - Closed for purposes of issuance of the operating license.

Issue	Section(s)	Status*
(39) penetration seals	9.5.1.4.1	Closed (SSER-2)
(40) stairwell fire barriers	9.5.1.4.1	Closed (SSER-2)
(41) steamtight doors	9.5.1.4.1	Closed (SSER-2)
(42) metal roof deck construction	9.5.1.4.1	Closed (SSER-2)
(43) floor drains	9.5.1.4.1	Closed (SSER-2)
(44) safe shutdown	9.5.1.4.2	Closed (SSER-2)
(45) alternate shutdown	9.5.1.4.3	Closed (SSER-2)
(46) storage of flammable gases	9.5.1.4.4	Closed (SSER-2)
(47) control structure ventilation	9.5.1.4.6	Closed (SSER-2)
(48) emergency lighting	9.5.1.4.7	Closed (SSER-2)
(49) fire detection	9.5.1.5.1	Closed (SSER-2)
(50) fire protection water supply	9.5.1.5.2	Closed (SSER-2)
(51) valve supervision	9.5.1.5.2	Closed (SSER-2)
(52) sprinkler and standpipe headers	9.5.1.5.3	Closed (SSER-2)
(53) standpipe flow calculation	9.5.1.5.3	Closed (SSER-2)
(54) seismic support of standpipe	9.5.1.5.3	Closed (SSER-2)
(55) PGCC design	9.5.1.5.5	Closed (SSER-2)
(56) control room complex design	9.5.1.6.2	Closed (SSER-2)
(57) cable spreading	9.5.1.6.3	Closed (SSER-2)
(58) diesel generator room protection	9.5.1.6.6	Closed (SSER-2)
(59) cooling towers	9.5.1.6.8	Closed (SSER-2)
(60) solidification/dewatering of solid waste (procedures)	11.4	R
(61) operating and maintenance procedures	13.5.2.2	Closed (SSER-2)
(62) emergency operating procedures	13.5.2.3	Closed (SSER-2)
(63) assurance of proper ESF functioning (II.K.1.5)	15.9.3	R
(64) procedures to ensure operability status (II.K.1.10)	15.9.3	Closed (SSER-2)
(65) automatic restart of RCIC (II.K.3.13)	15.9.4	Closed (SSER-2)
(66) preclude spurious isolation of RCIC and HPCI (II.K.3.15)	15.9.4	Closed (SSER-2)

1.10 License Conditions

Resolution of issues reported closed in this Supplement No. 2 have resulted in the need for license conditions in addition to the 16 potential license condition items identified in Supplement No. 1. They are as follows.

License Condition	Section
(17) Exception to the schedular requirements of the Standard Review Plan for certain fire protection items	9.5.1
(18) ATWS Events (Generic Letter 83-28)	15.8

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*R - Resolution reported in SSER-3
Closed - Closed for purposes of issuance of the operating license.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.2 Classification of Structures, Systems and Components

3.2.2 System Quality Group Classification

As was noted in the SER, the NRC staff acceptance of the system quality group classification of structures, systems, and components was contingent upon the applicant revising Tables 3.2-1 and 3.2-2 of the FSAR. These tables have been revised in Revision 34 to the FSAR. Table 3.2-1, in part, identifies the quality group classification and the appropriate codes and standards for major components in fluid systems such as pressure vessels, heat exchangers, storage tanks, pumps, piping, and valves, and mechanical systems such as cranes, refueling platforms and other miscellaneous handling equipment. Table 3.2-2 is a summary list of codes and standards for balance of plant (non-nuclear steam supply system) components and the applicable quality group classification. Table 3.2-2 is supplemented by Table 3.2-3 which is a summary list of codes and standards for nuclear steam supply system components and the applicable quality group classification.

The NRC staff has reviewed revised Tables 3.2-1 and 3.2-2 and new Table 3.2-3 and they are acceptable. The NRC staff concludes that the classification of structures, systems, and components and the construction of components in fluid systems in conformance with the ASME Code and industry standards identified in Tables 3.2-1, 3.2-2, and 3.2-3, the Commission's regulations, and the guidance provided in R.G. 1.26 provides assurance that component quality is commensurate with the importance of the safety function of these systems and constitutes an acceptable basis for satisfying the requirements of GDC 1 and is, acceptable.

3.6 Protection Against Dynamic Effects Associated With The Postulated Rupture Of Piping

3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment

In our SER we stated that the applicant had not provided sufficient information in the form of FSAR tables and figures to allow us to complete our review of this section. The applicant provided this information up through amendment 28 to the FSAR. We have reviewed the additional information and have performed an independent calculation of the environmental conditions following a high pressure coolant injection system steam supply steam pipe break. Our calculations indicate that the applicant's method of calculating compartment environmental conditions is accurate and conservative.

Based on the above, we find that the applicant has adequately designed and protected areas and systems required for a safe shutdown following postulated events, including determination of environmental conditions following a high energy pipe break. We conclude that the design of the facility for providing protection from high and moderate energy pipe failures and effects meets the applicable acceptance criteria of SRP Section 3.6.1 and is therefore acceptable.

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

In Section 3.6.2 of the Limerick SER, the staff identified a concern regarding the feedwater isolation check valves design adequacy to withstand the loads associated with a postulated feedwater line break outside containment. The staff has reviewed the information submitted by the applicant in letters dated August 29, 1983 and November 4, 1983. The applicant presented the results of an evaluation of the structural integrity of the feedwater isolation check valves including feedwater piping subjected to dynamic impact loads resulting from a postulated rupture of the feedwater piping outside containment. The approach used for evaluation included calculations of (1) the rate of reverse flow from the reactor vessel to the pipe rupture location, (2) the rate of check valve disk closure, (3) the energy observed from mechanical impact of the disk, (4) the stress analysis of the valve internals including hinge pin and valve seat/disk interface, (5) the fluid pressure surge for disk closure and (6) the effects of the pressure surge on the associated piping. The analysis results indicated that local yielding of the valve seat material would occur. However, the analysis results showed that a significant margin would remain with respect to ultimate strain limits and, thus, the structural integrity of the valve would be retained. The applicant also stated that the calculated pressure surge from disk closure was within the feedwater piping pressure design criteria. Based on a review of the information presented in the applicant's August 29 and November 4, 1983 letters, the staff determined that the applicant's analysis of the feedwater isolation check valve design adequacy to withstand the loads associated with a postulated feedwater line break outside containment is acceptable, therefore, the staff considers this issue resolved.

In Section 3.6.2 of the SER, the staff stated that the applicant has yet to submit piping isometrics showing break locations and break exclusion areas for the staff's review. Tables and figures in Section 3.6 of the FSAR which contain this information have been completed. The piping isometric drawings identify the locations at which breaks in high energy pipe are postulated to occur. These drawings also show the break exclusion zones applicable to high energy piping in the containment penetration areas. Based on a review of the information provided by the applicant, the staff has determined that the pipe break criteria established in FSAR Section 3.6 have been properly implemented by the applicant and, therefore, the staff considers this confirmatory issue closed.

In Section 3.6.2 of the SER, the staff also addressed the issue of the unrestrained pipe whip effects. The applicant has indicated that there are four instances of unrestrained whipping pipe inside containment. The response to MEB SER Question 210.38 as contained in FSAR Revision 26 stated that each of these lines has been evaluated, using the guidance of Regulatory Guide 1.46, to verify that in the event of a pipe break, damage to structures, systems, or components needed for safe shutdown would not occur. Therefore, the ability to shut the reactor down safely is maintained if a break should occur in any of these lines. Based on a review of the information provided by the applicant, the staff concluded that the four instances of unrestrained whipping pipe inside containment are acceptable and, therefore, the staff considers this confirmatory issue closed.

3.7 Seismic Design

3.7.3 Seismic Subsystem Analysis

Control Room Ceiling Failures

In Supplement No. 1 to the SER the staff stated that on November 4, 1982, Lawrence Livermore National Laboratory (LLNL) transmitted information to the NRC regarding control room ceiling failures (letter dated November 4, 1982, Cummings, LLNL, to D. G. Eisenhut, NRC). That letter enclosed photographs of several buildings at LLNL taken during the 1980 Livermore, California, earthquake. Ceiling collapses occurred in several buildings at LLNL, including the LLNL computer building. The letter further noted the connection between the experience at LLNL and what could happen in a nuclear power plant control room with unsecured ceilings.

This matter was considered by the staff and its consultants during its review of the Limerick Severe Accident Risk Assessment report. As stated in the Brookhaven National Laboratory report, NUREG/CR-3493, "A Review of the Limerick Generating Station Severe Accident Risk Assessment" the control room ceiling was examined during a tour of the Limerick plant. The ceiling at Limerick was found to consist of a light weight "egg-crate" structure which is supported by wires and braced between walls. There are no transite reflector panels located above the ceiling as previously found in similar applications at another power plant. Therefore, it is concluded that the ceiling at Limerick does not pose an undue hazard during a seismic event.

On the above basis the concern as addressed in Supplement No. 1 to the SER is considered to be closed.

3.9 Mechanical Systems and Components

3.9.2 Dynamic Testing and Analysis of Systems, Components and Equipment

3.9.2.1 Piping Preoperational Vibration and Dynamic Effects Testing

In Section 3.9.2.1 of the SER, the staff stated that the applicant committed to provide a startup test specification for BOP piping. In a letter from K. C. Blanton to R. E. Martin dated June 6, 1984, the applicant provided a copy of the startup test specification pertinent to BOP piping vibration, thermal expansion and dynamic effects testings. Based on a review of the information provided by the applicant, the staff determined that the test specification is acceptable. It consists of a list of systems that will be monitored and a list of selected locations in the piping system at which visual inspections and measurements (as needed) will be performed during piping vibration, thermal expansion and dynamic effects testing for BOP piping. The staff considers this confirmatory issue closed.

3.9.2.4 Dynamic System Analysis of Reactor Internals Under Faulted Condition

In Section 3.9.2.4 of the SER, the staff stated that the applicant committed to document the results of its analysis of the reactor internals and unbroken loops of the reactor coolant pressure boundary, including the supports, for the combined loads due to a simultaneous LOCA and SSE including the effects of annulus pressurization. In Appendix 6A of the FSAR, the applicant stated that the GE topical report NEDO-24548, "Technical Description - Annulus Pressurization Load Adequacy Evaluation", was utilized in the Limerick annulus pressurization analysis. This topical report was approved by the staff during the Susquehanna annulus pressurization analysis review. We have reviewed the results of the applicant's analysis of reactor internals provided in Section 3.9.2.5 of Revision 27, FSAR. We find that the applicant's results meet the applicable design basis acceptance criteria described in FSAR Table 3.9-6 (b) and, therefore, the staff considers this confirmatory issue closed.

3.10 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

3.10.2 Operability Qualification of Mechanical Equipment

II.K.3.28 Verify Qualification of Accumulators on ADS Valves

1.0 Background

The applicant's Final Safety Analysis Report states that air or nitrogen accumulators for the automatic depressurization system (ADS) valves are provided with sufficient capacity to cycle the valves open five times at design pressures. Based on the requirements of NUREG-0737 Item II.K.3.28 it is necessary to demonstrate that the ADS valves, accumulators, and associated equipment and instrumentation meet the requirements specified in the plant FSAR and are capable of performing their functions during and following exposure to hostile environments, taking no credit for non-safety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through the valves must be accounted for to assure that enough inventory of compressed gas is available to cycle the ADS valves. If this cannot be demonstrated, it must be shown that the accumulator design is still acceptable. Since this system is a part of the emergency core cooling system it must still perform its function for the long term period of 100 days following the accident.

2.0 Discussion

The nuclear pressure relief system utilizes dual function safety/relief valves (MSRVs). Five of these valves were selected for automatic reactor depressurization through an accumulator and check valve arrangement. The Limerick ADS accumulator system consists of the ADS safety/relief valve, its solenoid-operated control valves and circuits, accumulator, check valve at the inlet to the accumulator, interconnecting piping, and the supports for these components.

The applicant submitted the following to demonstrate compliance with the requirements of TMI Action Item II.K.3.28.

A. Letters from E. J. Bradley, Philadelphia Electric Co. to A. Schwencer NRC dated October 5, 1983 and revised December 23, 1983 which provides responses to NRC requests for additional information.

B. LGS-FSAR, Revision 25, dated October 10, 1983, Sections 1.13.1, 5.2 and 9.3, and P and ID No's. M41 and M59.

C. Letter from E. J. Bradley, Philadelphia Electric Company to A. Schwencer, NRC dated June 21, 1984 providing a revised response to an NRC request for information.

There are several systems provided to supply gas for the accumulators. First, each accumulator capacity is sufficient for operation for a period of 6 hours, assuming maximum allowable leakage from the system. Second, the Instrument Air System keeps the accumulator normally supplied with air. Since this is non-safety grade, a safety grade nitrogen system is provided as backup for a 7-day period. This is referred to as short term system operation. Finally, long term operation at the expiration of the 7 days is provided by installing an alternate supply at an externally accessible connection to the safety grade back-up system.

As described in the FSAR and supplemented by the P&ID No's M-41 and M-59, the accumulator system is sized to provide two ADS safety/relief (S/RV) valve actuations at 70% of drywell design pressure. Analysis has shown this to be equivalent to 4-5 actuations at atmospheric pressure in the drywell. The basis for the 70% of drywell design pressure is that is the maximum pressure for which rapid reactor depressurization through the ADS valves is required. Larger breaks which produce higher drywell pressures are sufficient to depressurize the reactor due to the break alone. One S/RV actuation at 70% is sufficient to depressurize the reactor until the RHR shutdown cooling mode can be initiated.

3.0 Applicant's Demonstration of Qualification

In the event the normal Instrument Air Supply is lost, the safety grade nitrogen system provides backup. There are two groups of 3 nitrogen bottles; each group is located in separate areas of the reactor building. The accumulators are located in the drywell. The nitrogen bottles provide the 7-day supply to the accumulators in the event RHR shutdown cooling is not available.

At the expiration of 7 days, additional gas supply to the existing backup system must be available. To provide this the backup system piping has a connection outside the reactor building ensuring access during post accident conditions. This permits connection to an air compressor and/or additional nitrogen bottles for ensuring long term ADS-SRV operations for an indefinite period. The ADS and the backup system are designed to seismic category 1 criteria.

The applicant has established that the allowable leakage criteria of 173 scc/min. assures two ADS-SRV actuations at 70% of drywell design pressure over a period of six (6) hours following the loss of pneumatic air supply to the accumulators.

This leakage is to ensure operability for the most adverse containment conditions. The applicant indicated that the 173 scc/min. already includes a margin of 46 scc/min. for identified leakage over the requirements calculated. This margin is to account for harsh conditions and seismic loads, and is obtained by oversizing the accumulators. In addition, 78 scc/min. is the established leakage for surveillance testing; this provides an additional margin of 49 scc/min. In any event, the safety grade nitrogen cylinder supply provides backup. Furthermore, the applicant has taken no credit for non-safety related equipment and instrumentation when establishing the allowable leakage criteria.

The LGS design provides alarms and instrumentation associated with the backup safety grade pneumatic supply. High and low pressure alarms in the control room are provided for the two pneumatic headers which supply the ADS accumulator system. This will alert the operator if the accumulators are not being charged properly.

Upon containment isolation signal, the isolation valves for the ADS accumulator system remain open thus assuring its availability. However system instrumentation and controls will isolate the ADS valve gas supply when the air supply system pressure falls below primary containment pressure, thereby isolating a gas supply leak. Indication of valve position for the containment isolation valves and solenoid valves on the backup ADS gas supply header is furnished in the control room. The backup design has local pressure indication on each gas bottle, the feeder lines and the main headers. The pressures are monitored by plant operations personnel daily.

The P and ID's were examined to assure safety related portions of the system were correctly identified and system operation is compatible with the description provided by the applicant.

The applicant has confirmed that all the applicable components were designed and procured to meet seismic and environmental qualification criteria. This included appropriate testing and analysis, except for the gas bottles. The gas bottles are the equivalent of seismic qualified since they met Department of Transportation standards, Title 49, Section 178.37, Specification 3AA, and Interstate Commerce Commission Specifications; they are supported with seismic Category I supports.

4.0 Evaluation

4.1 The staff has reviewed the actuation capability, design and operation of the ADS accumulator system. We find this acceptable because it complies with the performance requirements following an accident as stated in Section 1, Background.

4.2 The staff has reviewed the applicant's statements regarding the leakage criteria and the leakage margin and bases. We find these acceptable because a) the applicant estimates of gas supply requirements and oversizing the accumulators are conservative, b) the applicant has considered potential degradation effects from harsh environment and, c) no credit was taken by the applicant for non-safety related equipment and instrumentation.

4.3 The staff has reviewed the Technical Specifications which will apply to LGS. These include system functional tests, and calibration of alarms each 18 months; channel functional tests of the system alarms are required each 31 days. The applicant has additionally confirmed in writing to monitor the local pressure in the supply gas bottles and in the header on a daily basis. This provides added assurance of system availability. The staff finds the surveillance provisions acceptable to assure system operability.

4.4 The staff has reviewed the applicant commitments confirming that the ADS valves, accumulators and backup system up to and including the external accessible connection were designed, procured and qualified to meet plant environment and seismic conditions. The staff finds these acceptable.

4.5 The staff has examined P and ID.'s M-41 and M-59 and finds it supports the applicants design description. The staff accepts the applicants position that no credit for non-safety related equipment and instrumentation was taken in establishing the capability of the system to function during and following an accident.

Conclusions

Based upon the above evaluation the staff finds that the applicant has incorporated into the ADS valve/accumulator design sufficient measures to meet the requirements of TMI action Item II.K.3.28. The staff therefore concludes that the TMI Action Item II.K.3.28 has been satisfactorily resolved and that this issue is closed.

3.10.3 Seismic, Dynamic and Operability Qualification of Containment Purge and Vent Valves

3.10.3.1 Requirement

Demonstration of operability of the containment purge and vent valves, particularly the ability of these valves to close during a design basis accident, is necessary to assure containment isolation. This demonstration of operability is required by BTP CSB 6-4 and SRP 3.10 for containment purge and vent valves which are not sealed closed during operational conditions 1, 2, 3, and 4. The NRC staff requested additional information by letter dated July 30, 1982 to support the review of the operability qualification of the purge and vent valves. The Philadelphia Electric Company (PECo), in their letters dated July 7, 1983, September 1, 1983, and December 16, 1983 provided the operability demonstration information for the purge and vent valves in their Limerick Generating Stations, Units 1 and 2.

3.10.3.2 Description

Valve Number	Valve Size (Inches)
HBB-BF-MO-57-115	24
-135	"
-147	"
HBB-BF-AO-57-114	"
-123	"
-124	"
HBB-BF-AO-57-104	18
HBB-BF-MO-57-112	"
HBB-BF-AO-57-121	6
-131	"
HBB-BF-MO-57-109	"
-162	"
-164	"
HBB-BF-MO-57-161	4
-163	"

The subject valves are butterfly type, Tricentric model, manufactured by Clow Corporation. The air operated valves (designated by AO) are equipped with actuators manufactured by G.H. Bettis and the motor operated valves (designated by MO) are equipped with actuators manufactured by Limitorque Corporation.

The following table identifies the model number of the actuator mounted on each of the subject valves:

Valve Number	Actuator Model Number
-115	SMB3-80-H5BC
-135	"
-147	"
-123	"
-104	NT 820-SR5-S
-112	SMB1-60-H5BC
-121	NT-312-SR5
-131	"
-109	SMB-00-10-H2BC
-162	"
-164	"
-161	SMB-00-10-H1BC
-163	"

The subject valves are to be operated from their full open position.

3.10.3.3 Demonstration of Operability

As mentioned above the Philadelphia Electric Company (PECo), in their letters dated July 7, 1983, September 1, 1983, and December 16, 1983 provided the operability demonstration information for the purge and vent valves in their Limerick Generating Stations, Units 1 and 2.

A seismic qualification analysis was conducted on each size valve to verify the structural integrity. A finite element model was developed to simulate valve components. The model was subjected to static seismic accelerations combined with operating loads. The design was shown to be in conformance with the ASME Section III-1980 edition through and including the Summer of 1981, Addenda as specified.

The basic approach taken for this seismic qualification analysis was:

A. Utilize finite element techniques to formulate a mathematical model of the valve.

B. Calculate the valve fundamental natural frequency.

C. Apply the static analysis method to determine stresses, forces and deflections for operating, and seismic loading conditions.

D. Calculate resultant stresses against appropriate allowable stresses.

The ANSYS finite element computer program developed by Swanson Analysis Systems, Inc., Houston, Pennsylvania, was used to develop a mathematical model and to determine frequencies, stresses, forces, and displacements. ANSYS computations were performed on the Control Data Cybernet System.

An assessment of actuator capability was also made to establish that each of the actuators was capable of stroking its respective valve closed from the valve full open position against the DBA-LOCA related loads.

In their assessment, PECo considered torque margin available, actuator design torque and torque switch settings (electric motor actuators).

3.10.3.4 Evaluation

A. In their July 7, 1983 submittal, PECo provided a copy of the Clow report entitled "Purge and Vent Valve Operability Qualification Analysis." The report contained information that demonstrated that in no case do the aerodynamic torques developed in a valve exceed the "Design Torque" used in the stress analysis of critical valve parts.

The Clow analysis assumes worst case postulated accident conditions; peak containment pressure taken from the LOCA containment pressure response curves with no credit taken for ramp pressure rise and single valve closure; which the staff finds acceptably conservative.

In predicting aerodynamic torques, PECo has shown that valve installation configuration, i.e., elbow effect, shaft orientation, etc. were considered and that the aerodynamic torque coefficients used stemmed from a model valve (tricentric design) bench test program that included elbows in the upstream piping configuration as well as straight pipe inlet configurations.

The bench test program established "Torque Multiplication Factors" (TMF) for the various configurations tested which the straight pipe inlet configuration TMF baselined at 1.0.

PECo reviewed the installation configurations of each valve and applied either an applicable TMF or a conservatively assumed TMF value in determining the maximum aerodynamic torques developed in the particular valve.

The following table is a summary of the maximum aerodynamic torque load potential of each valve compared to the "Design Torque" load.

Valve Number	Maximum Aerodynamic Torque (in-lbs)	Design Torque (in-lbs)
-115	97,075	135,000
-135	97,075	"
-147	97,075	"

Valve Number	Maximum Aerodynamic Torque (in-lbs)	Design Torque (in-lbs)
-114	97,075	"
-123	115,970	"
-124	115,970	"
-104	48,450	63,300
-112	48,450	"
-121	2,400	7,800
-131	2,400	"
-109	2,400	"
-162	2,400	"
-164	2,400	"
-161	740	2,112
-163	740	"

PECo's September 1, 1983 submittal included a copy of the stress analysis report for each valve size, i.e., PEI-TR-83-13 (24-inch), -14 (18-inch), -15 (6-inch), and -16 (4-inch). The reports showed that the design torque loads used for the stress analysis were as follows:

Valve Size (Inches)	Design Torque (in-lbs) (Seating Torque)
4	2,112
6	7,800
18	63,300
24	135,000

Using these torque loads, the staff concludes that the stress levels in the critical valve parts analyzed were less than the stress allowables of the part material for the load or load combinations used. In all cases, the stress ratios, i.e., maximum stress divided by allowable stress were shown to be less than 1.

B. In addition to the torque load information, the submittals provided information concerning the pressure loads used in the stress analysis. The Body Design Pressure (285 psig) and Disc Differential Pressure (65 psig) are conservative in that they exceed the peak containment pressure potential of 56 psig.

C. Based on the information contained in the submittals, the staff finds that PECo has demonstrated that the designs of the valve critical parts are adequate to withstand the loads encountered during the DBA-LOCA (see Sections 4.1 and 4.2).

D. The information provided by PECo has demonstrated that the valve actuators are capable of closing their respective valves from the full open position against the buildup of containment pressure during a DBA/LOCA. PECo used the following criteria in assessing the capability of the air-spring type actuators:

Criteria 1 - Actuator torque output must overcome with sufficient margin the worst case torque that resists valve closure.

Criteria 2 - Peak aerodynamic induced closing torque must not exceed the actuator design torque.

In assessing the capability of electric motor type actuators, PECo applied the following criteria:

Criteria 1 - Same as Criteria 1 used for the air-spring type actuators.

Criteria 2 - Same as Criteria 2 used for the air-spring type actuators.

Criteria 3 - The worst case torque that resists valve closure must be less than the torque switch closure trip setting.

The following table summarizes the torque information provided by PECo and indicate the margins available to satisfy the specified criteria.

Valve with Air-Spring Type Actuators.

Valve Number	Criteria 1	Criteria 2
-121	Aerodynamic torques developed tend to aid valve closure. The torque margin available for closure is at the least the actuator spring torque capability.	The maximum aerodynamic torques i.e., 97,075 (-114) and 24,000 in-lbs (-121 and -131) are less than the safe structural torques i.e., 26,688 in-lbs (-121 and -131) and 211,000 in-lbs (-114) of the actuators.
-104 -123 -124	Aerodynamic torques developed in the first 5° from full open tend to resist valve closure. The worst case closure resisting aerody namic torques are 48,450 in-lbs (-104) and 115,970 in-lbs (-123 and -124). The spring torque potentials are at 0° least 76,096 in-lbs (-104) and 124,695 in-lbs (-123 and -124) in the first 5°.	The maximum aerodynamic torques i.e., 48,450 in-lbs (-104) and 115,970 in-lbs (-123 and -124) are less than the safe structural torques i.e., 175,000 in-lbs (-104) and 211,000 in-lbs (-123 and -124) of the actuators.

Valves with Electric Motor Type Actuators.

Valve No.	Criteria 1	Criteria 2	Criteria 3
-109 -161	Aerodyanmic torques developed tend to	The maximum aerody namic torques i.e.,	Aerodynamic torques developed tend to

Valves with Electric Motor Type Actuators. (Continued)

Valve No.	Criteria 1	Criteria 2	Criteria 3
-162 -163 -164	aid valve closure. The torque output capability of the actuators is the margin available.	740 in-lbs (-161 & -163) and 2,400-in lbs (-109, -162, & -164 are less than the safe structural torques i.e., 15,600 in-lbs (-161 & -163) and 26,400 in-lbs (-109, -162, & -164) of the actuators.	aid valve closure. The HBC unit motor of the actuator assembly has a self locking gear set that prevents these torques from being transmitted to the torque sensing device.
-112 -115 -135 -147	Aerodynamic torques developed in the first 5° from full open tend to resist valve closure. The worst case closure resisting aerodynamic torques are 2,127 in-lbs (-112) and 11,550 in-lbs (-115, -135, & -147). The actuator torque capability i.e., actuator torque that can be used to overcome those aerodynamic torques that resist closure are 34,000 in-lbs (-112) and 55,000 in-lbs (-115, -135, & -147).	The maximum aerodynamic torques i.e., 48,450 in-lbs (-112) and 97,075 in-lbs -115, -135, & -147) are less than the safe structural torques i.e, 235,000 in-lbs (-112, -115, -135, & -147) of the actuators.	The aerodynamic torques developed in the first 5° from full open i.e., 2,127 in-lbs (-112) and 11,550 in-lbs (-115, -135, & -147) are less than the torques switch settings of 55,000 in-lbs (-115, -135, & -147) and 34,000 in-lbs (-112). Aerodynamic torques developed after the first 5° tend to aid valve closure. The self locking gear set in the HBC unit motor prevents these closing torques from being transmitted to the torque sensing device.

E. The staff finds that seismic qualification for the containment purge and vent valves has been addressed by the applicant in the following reports prepared by Patel Engineers of Huntsville, Alabama.

1. Report PEI-TR-83-16 Rev. A for Clow 4-inch wafer stop valve (April 1983).
   Mark numbers 4 inch-HBB-BF-MO-57-161 and -163.
   Clow job number 82-2053-01-(N)-01 and 02.

2. Report PEI-TR-83-15 Rev. A for Clow 6-inch wafer stop valve (April 1983)
   Mark numbers 6 inch-HBB-BF-MO-57-109, -162, and -164
   6 inch-HBB-BF-AO-57-121 and -131
   Clow job number 82-2053-02(N)-01, -02, and -03
   82-2053-02(N)-01, and -02

3. Report PEI-TR-83-14 Rev. A for Clow 18-inch wafer stop valve (April 1983)
   Mark numbers 18 inch-HBB-BF-MO-57-104
   18 inch-HBB-BF-AO-57-112
   Clow job number 82-2053-04(N)-01
   82-2053-05(N)-01

4. Report PEI-TR-83-13 Rev. A for Clow 24-inch wafer stop valve (April 1983)
   Mark numbers 24 inch-HBB-BF-MO-57-115, -135, and -147
   24 inch-HBB-BF-AO-57-114, -123, and -124
   Clow job number 82-2053-06(N)-01, -02, and -03
   82-2053-07(N)-01, -02, and -03

3.10.3.5 Summary

We have completed our review of information submitted to data concerning operability of the 4, 6, 18, and 24-inch containment purge and vent valves at the Limerick Generating Station, Units 1 and 2. We find that the information submitted has satisfactorily demonstrated the ability of the valves to close against the buildup of containment pressure in the event of a DBA/LOCA.

3.11 Environmental Qualification of Electrical Equipment Important to Safety and Safety-Related Mechanical Equipment

3.11.1 Introduction

Equipment that is used to perform a necessary safety function must be demonstrated to be capable of maintaining functional operability under all service conditions postulated to occur during its installed life for the time it is required to operate. This requirement--which is embodied in General Design Criteria (GDC) 1 and 4 of Appendix A and Sections III, XI, and XVII of Appendix B to 10 CFR 50--is applicable to equipment located inside as well as outside containment. More detailed requirements and guidance relating to the methods and procedures for demonstrating this capability for electrical equipment have been set forth in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," which supplements the Institute of Electrical and Electronics Engineers (IEEE) Standard 323; and various NRC regulatory guides (RGs) and industry standards.

3.11.2 Background

NUREG-0588 was issued in December 1979 to promote a more orderly and systematic implementation of equipment qualification programs by industry and to provide guidance to the NRC staff for its use in ongoing licensing reviews. The positions contained in that report provide guidance on (1) how to establish environmental service conditions, (2) how to select methods that are considered appropriate for qualifying equipment in different areas of the plant, and (3) other areas such as margin, aging, and documentation. In February 1980, the NRC asked certain near-term OL applicants to review and evaluate the environmental qualification documentation for each item of safety-related electrical equipment and to identify the degree to which their qualification programs were in compliance with the staff positions discussed in NUREG-0588.

IE Bulletin 79-01B, "Environmental Qualification of Class 1E Equipment," issued by the NRC Office of Inspection and Enforcement (IE) on January 14, 1980, and its supplements dated February 29, September 30, and October 24, 1980, established environmental qualification requirements for operating reactors. This bulletin and its supplements were provided to operating license (OL) applicants for consideration in their reviews.

A final rule on environmental qualification of electrical equipment important to safety for nuclear power plants became effective on February 22, 1983. This rule, Section 50.49 of 10 CFR 50, specifies the requirements to be met for demonstrating the environmental qualification of electrical equipment important to safety located in a harsh environment. In conformance with 10 CFR-50.49, electrical equipment for Limerick Generating Station (LGS) may be qualified according to the criteria specified in Category II of NUREG-0588.

The qualification requirements for mechanical equipment are principally contained in Appendices A and B of 10 CFR 50. The qualification methods defined in NUREG-0588 can also be applied to mechanical equipment.

To document the degree to which the environmental qualification program complies with the NRC environmental qualification requirements and criteria, the applicant provided equipment qualification information by letters dated October 7, 1983, January 16, 1984, February 16, 1984, April 6, 1984, August 31, 1984, and September 7 and 10, 1984 to supplement the information in FSAR Section 3.11.

The staff has reviewed the adequacy of the LGS environmental qualification program for electrical equipment important to safety as defined in 10 CFR 50.49 and the program for safety-related mechanical equipment. The scope of this report includes an evaluation of (1) the completeness of the list of systems and equipment to be qualified, (2) the criteria they must meet, (3) the environments in which they must function, and (4) the qualification documentation for the equipment. It is limited to electrical equipment important to safety within the scope of 10 CFR 50.49 and safety-related mechanical equipment.

3.11.3 Staff Evaluation

The staff evaluation included an onsite examination of equipment, an audit of qualification documentation, and a review of the applicant's submittals for completeness and acceptability of systems and components, qualification methods, and accident environments. The criteria described in Section 3.11 of the NRC Standard Review Plan (SRP, NUREG-0800), Revision 2, in NUREG-0588 Category II, and the requirements in 10 CFR 50.49 form the bases for the staff evaluation.

The staff performed an audit of the applicant's qualification documentation and installed electrical equipment on March 14, 15, and 16, 1984. The audit consisted of a review of 12 files containing information regarding the equipment qualification. The staff's findings from the audit are discussed in detail in Section 3.11.4.2 of this report.

3.11.3.1 Completeness of Equipment Important to Safety

10 CFR 50.49 identifies three categories of electrical equipment that must be qualified in accordance with the provisions of the rule.

(1) safety-related electrical equipment (equipment relied on to remain functional during and following design-basis events)

(2) nonsafety-related electrical equipment whose failure under the postulated environmental conditions could prevent satisfactory accomplishment of the safety functions by the safety-related equipment

(3) certain post-accident monitoring equipment (RG 1.97, Category 1 and 2 post-accident monitoring equipment).

The applicant has provided information addressing compliance with this requirement of 10 CFR 50.49.

The systems identified by the applicant for the environmental qualification program as being required to function to mitigate the consequences of loss-of-coolant accidents (LOCAs) or high-energy line breaks (HELBs) that have components located in a harsh environment were compared to FSAR Table 3.2-1, "LGS Design Criteria Summary." The omission of systems from the harsh environment program was adequately justified by the applicant. Table 3.11.1 lists the systems identified and their safety function.

To address conformance with 10 CFR 50.49(b)(2) concerning nonsafety-related equipment whose failure under postulated accident conditions could prevent the satisfactory accomplishment of safety functions, the applicant referred to staff reviews of the responses to IE Information Notice 79-22, "Qualification of Control Systems," and conformance with RG 1.75, "Physical Independence of Electric Systems." The staff has reviewed and evaluated the applicant's conformance with RG 1.75 and found it acceptable as it relates to equipment qualification. The staff has also reviewed and evaluated the applicant's response to IE Information Notice 79-22 and found it acceptable as stated in Section 7.7 of this report. Based on this, the staff concludes that the applicant's conformance to 10 CFR 50.49(b)(2) is acceptable.

10 CFR 50.49(b)(3) requires that all installed RG 1.97, Category 1 and 2 instrumentation located in a harsh environment be included in the equipment qualification program unless adequate justification is provided. The applicant has indicated that all such equipment is included in the qualification program; however, in addressing conformance with RG 1.97, the applicant has identified a number of exceptions. The staff will determine the acceptability of these exceptions as part of its review for conformance with RG 1.97. This review may result in the addition of equipment to the environmental qualification program.

3.11.3.2 Qualification Methods

3.11.3.2.1 Electrical Equipment in a Harsh Environment

Detailed procedures for qualifying safety-related electrical equipment in a harsh environment are defined in NUREG-0588. The criteria in this NUREG are also applicable to the other equipment important to safety defined in 10 CFR 50.49.

The staff has reviewed the methods used by the applicant to demonstrate qualification to assure that they are in compliance with NUREG-0588, Category II.

3.11.3.2.2 Safety-Related Mechanical Equipment in a Harsh Environment

Although there are no detailed requirements for mechanical equipment, GDC 1, "Quality Standards and Records," and 4, "Environmental and Missile Design Bases," and Appendix B to 10 CFR 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" (Sections III, "Design Control," and XVII, "Quality Assurance Records"), contain the following requirements related to equipment qualification:

- Components shall be designed to be compatible with the postulated environmental conditions, including those associated with LOCAs.
- Measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to safety-related functions.
- Design control measures shall be established for verifying the adequacy of design.
- Equipment qualification records shall be maintained and shall include the results of tests and materials analyses.

The results of the safety-related mechanical equipment qualification program have been submitted to the staff for review. In addition, qualification documentation for three items of safety-related mechanical equipment has been submitted by the applicant and has been reviewed by the staff. The staff review has verified that the requirements for environmental qualification of safety-related mechanical equipment have been adequately addressed.

3.11.3.3 Service Conditions

NUREG-0588 defines the methods to be utilized for determining the environmental conditions associated with LOCAs or HELBs, inside or outside of containment. The review and evaluation of the adequacy of these environmental conditions are described below. The staff has reviewed the qualification documentation to ensure that the qualification conditions envelop the environmental conditions established by the applicant.

3.11.3.3.1 Temperature, Pressure, and Humidity Conditions Inside the Primary Containment

The applicant has provided the generic NUREG-0588 LOCA/main steamline break (MSLB) temperature profile as the bounding drywell temperature profile used for the equipment qualification program. The peak values in the drywell shown on this profile are as follows:

	Maximum temperature, °F	Maximum pressure, psig	Humidity, %
LOCA/MSLB	340	44	100

The staff finds this profile acceptable for use in equipment qualification; i.e., there is reasonable assurance that the actual pressures and temperatures will not exceed those profiles anywhere within the specified environmental zone (except in the break zone). The individual Equipment Qualification Review Records, however, reflect the use of a plant specific temperature profile. By letter dated September 7, 1984, the applicant informed the staff that the qualification documents for all equipment inside primary containment have been reviewed and that all equipment is qualified to the profile in NUREG-0588.

PECo intends to hold further discussions with the staff on the use of a plant specific containment temperature profile. The applicant also stated that by March 31, 1985 all environmental qualification files for equipment located inside primary containment will be updated to reflect the use of the NUREG-0588 qualification profile or the appropriate staff approved qualification profile. In the interim, a note will be added to each qualification package to reflect conformance with NUREG-0588.

The staff finds this course of action acceptable.

3.11.3.3.2 Temperature, Pressure, and Humidity Conditions Outside the Primary Containment

The applicant has provided the temperature, pressure, and humidity conditions associated with HELBs in the secondary containment. The staff has reviewed these environmental conditions and has verified that the parameters identified by the applicant are acceptable.

3.11.3.3.3 Submergence

The effects of flooding on equipment have been evaluated to ensure that safe shutdown can be achieved. The applicant has taken appropriate corrective action to relocate or qualify all affected equipment.

3.11.3.3.4 Demineralized Water Spray

A demineralized water spray could be used inside primary containment to mitigate the effects of an accident. The effects of spray impingement on equipment important to safety have been evaluated by the applicant.

3.11.3.3.5 Aging

NUREG-0588, Category II outlines two aging program requirements. Valve operators committed to IEEE Standard 382-1972 and motors committed to IEEE Standard 334-1971 must meet the Category I requirements of NUREG-0588. This requires the establishment of a qualified life, with maintenance and replacement schedules based on the findings. For other equipment, the qualification program should address aging to the extent that age susceptible component materials are identified. In addition, a maintenance/surveillance program should be implemented to identify and prevent significant age-related degradation in electrical and mechanical equipment.

The applicant has committed to follow the recommendations in RG 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)," which endorses American National Standard ANS-3.2/ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants," as noted in SER Section 17. This standard defines the scope and content of a maintenance/surveillance program for safety-related equipment. Provisions for preventing or detecting age-related degradation in safety-grade equipment are specified and include (1) utilizing experience with similar equipment, (2) revising and updating the program as experience is gained with the equipment during the life of the plant, (3) reviewing and evaluating malfunctioning equipment and obtaining adequate replacement components, and (4) establishing surveillance tests and inspections based on reliability analyses, frequency and type of service, or age of the items, as appropriate. The applicant has stated that the maintenance/surveillance program will be implemented at the time of fuel load. In addition, a description of the surveillance program which will be used to address unanticipated age-related degradation of cables located inside containment was submitted by the applicant. The staff has reviewed the program description and finds it acceptable.

3.11.3.3.6 Radiation (Inside and Outside Containment)

The applicant has provided values of the radiation levels postulated to exist following a LOCA. The accident radiation environments in primary containment have been defined according to Section II.B.2 of NUREG-0737 and NUREG-0588, Revision 1. For this review, the staff has assumed that the values provided have been determined in accordance with the prescribed criteria. The staff review determined that the values to which the equipment is qualified enveloped the requirements identified by the applicant.

The maximum total radiation dose specified by the applicant for primary containment is 6.4×10^7 rads gamma. In the secondary containment, values of up to 5.29×10^6 rads gamma were used in the evaluation of equipment in areas exposed to recirculating fluid lines. These values are acceptable for use in the qualification of equipment.

3.11.4 Qualification of Equipment

By letters dated August 31, 1984 and September 10, 1984, the applicant has provided notification that all items in the Limerick Equipment Qualification Program are environmentally qualified. On the basis of the staff's review, all items in the Limerick EQ program have been determined to be acceptably qualified pending implementation of the maintenance/surveillance program.

3.11.4.1 Environmental Qualification Audit

The staff, with assistance from EG&G Idaho, Inc., conducted an audit of the applicant's qualification files on March 14, 15, and 16, 1984. The purpose of the audit was to verify the bases of the information submitted by the applicant. Twelve equipment qualification files, representing approximately 10% of the equipment items in the Equipment Qualification program, were selected for detailed review during the audit.

The equipment items selected for audit were:

1. Pressure Switch, Static-O-Ring model 6P3-K3M4C
2. Solenoid Valve, ASCO model THT826C7E
3. Temperature Element, MINCO model S9322
4. Terminal Block, Weidmuller model SAK 4, 6N, 10
5. Electrical Penetration Assembly, Conax model 10JX103A
6. Solenoid Valve, Target Rock model 1/2-SMS-A-01
7. Handswitch, General Electric model CR2940
8. Motor Operator, Limitorque model SB-2-60
9. Pressure Transmitter, Rosemount model 1151A
10. Terminal Block, Buchanan model NQB Series 100
11. Solenoid Valve, AVCO model C-5140
12. Electro Hydraulic Actuator, ITT-General Controls model NH95

These files were reviewed to determine if qualification had been demonstrated based on the documents contained in the files. In all cases it was determined that adequate proof was provided to establish qualification as claimed.

As part of the audit, the equipment as actually installed was inspected during a plant walkdown. The purpose of the walkdown was to verify manufacturer, model number, location and proper installation consistent with the qualification documents. No discrepancies were discovered.

3.11.5 Conclusions

The staff has reviewed the LGS program for the environmental qualification of electrical equipment important to safety and safety-related mechanical equipment. The purpose of the review was to determine the adequacy of the program, including the scope of the qualification program, the environmental conditions resulting from design-basis accidents, and the methods used to demonstrate qualification. Based on the results of our review, the staff concludes that the applicant has demonstrated conformance with the requirements for environmental qualification as detailed in 10 CFR 50.49, the relevant parts of GDC 1 and 4, and Sections II, XI, and XVII of Appendix B to 10 CFR 50, and with the criteria specified in NUREG-0588.

In addition to the conclusion stated above it is noted that a contention challenging the applicant's plan for implementing 10 CFR 50.49 was admitted for litigation in the hearing proceeding and was decided by the ASLB in favor of the applicant. See Second Partial Initial Decision, LBP-84-31 August 29, 1984, slip op pp 77-98.

Table 3.11.1

SAFETY-RELATED SYSTEMS
LIMERICK GENERATING STATION
ENVIRONMENTAL QUALIFICATION PROGRAM

System Name	Safety Function*
Class 1E Power Interfaces	7
Containment Atmospheric Control	3
Control Rod Drive	2
Core Spray	1
Drywell Chilled Water - Isolation Valves	3
Drywell HVAC	3
ECCS Pump Room HVAC	4, 2, 1
Emergency Service Water	4, 2, 1
Equipment and Floor Drains	3
High Pressure Coolant Injection	1
Main Steam Isolation Valve - Leakage Control	6
Nuclear Boiler Instrumentation	1, 2, 3, 4
Nuclear Boiler System	7
Nuclear Steam Supply Shutoff	3
Plant Leak Detection	3
Primary Containment Instrument Gas	3
Process Radiation Monitoring	6
Reactor Core Isolation Cooling	1
Reactor Enclosure Cooling Water - Isolation Valves	3
Reactor Enclosure HVAC - Recirculation Mode	2
Reactor Water Clean Up	3
Reactor Recirculation	3, 2
Residual Heat Removal	4, 3, 2, 1
Safeguard DC Power	7
Safeguard Piping Fill System	3, 5
Safety Relief Valve Position Indication	1
Standby Liquid Control	2
Standby Gas Treatment	3, 6
Supression Pool Cleanup	6
4 Kv Power	7
440v Load Centers and Motor Control Centers	7

*
1 - Core Coverage
2 - Safe Shutdown
3 - Containment Isolation
4 - Residual Heat Removal
5 - Containment Integrity
6 - Effluent Control
7 - All the Above

4 REACTOR

4.2 Fuel System Design

4.2.3 Design Evaluation

4.2.3.3 Fuel Coolability Evaluation

(1) Fragmentation of Embrittled Cladding

The SER included a confirmatory item subject to the receipt of documentation regarding the fission gas release calculations used for the Limerick plant. The SER noted, that under LOCA conditions that calculated fission gas release results in a maximum increase of 85 °F in calculated peak cladding temperature (PCI) at the end of life (33,000 MWd/t planar average exposure) which had not been explicitly accounted for in the Limerick ECCS analysis. The SER stated that credit could be given for certain PCT margins and ECCS evaluation model changes documented by GE to offset any penalties associated with the above 85 °F increase in PCT provided it was shown that the GE proposals were applicable to Limerick and that no additional credit is taken for the ECCS evaluation model changes. In response the applicant documented by letter dated August 17, 1983 that the GE proposal does apply to Limerick. The NRC staff therefore reaffirms that the effects of enhanced fission gas release at high burnup have been adequately considered in the Limerick safety analysis with regard to the potential fragmentation of embrittled cladding and considers this confirmatory item to be closed.

4.4 Thermal-Hydraulic Design

4.4.6 Loose Parts Monitoring System (LPMS)

At the request of the staff, the applicant has submitted additional information regarding the Loose Parts Monitoring System (LPMS) and program in a letter from J. Kemper (Philadelphia Electric Company) to A. Schwencer, dated February 21, 1984 and in Revision 29 of the FSAR (February, 1984). The applicant has indicated that the Limerick LPMS is in compliance with the Regulatory Guide 1.133 and also has agreed to submit the information regarding the power operation LPMS alert level within 90 days following completion of startup testing.

The staff has reviewed the Limerick LPMS program. Based on the applicant's evaluation that their LPMS is in compliance with Regulatory Guide 1.133, the staff has concluded that the Limerick LPMS is acceptable on the condition that the Technical Specifications include appropriate limiting conditions for operation and surveillance requirements to demonstrate the operability of LPMS. Therefore, the staff has concluded that the confirmatory item regarding LPMS has been resolved for Limerick.

4.4.7 Instrumentation for Detection of Inadequate Core Cooling (II.F.2)

In response to the staff's request, Philadelphia Electric Company has submitted a report with their transmittal letter of August 23, 1983. This report is their plant specific evaluation report addressing the applicant's position with respect to the BWROG report (SLI-8211, July 1982), "Review of the BWR Reactor Water Level Measurement Systems", and to SLI-8218 (November 1982), "Inadequate Core Cooling Detection in Boiling Water Reactors."

Page 4-29 of NURG-0991 lists three water level instrumentation concerns, identified in SLI-8211, which must be addressed for Limerick. In a letter from John S. Kemper (PECo) to A. Schwencer (NRC) dated August 23, 1983, PECo responded to these three concerns. We find the responses to be acceptable. The concerns and evaluation of the responses are given below.

Concern 1

The applicant should consider the BWROG recommendations for upgrading the water level instrumentation to reduce the errors caused by high drywell temperature.

Evaluation

For conditions in which there is no reference to leg boil-off or flashing the effect of high drywell temperature is negligible because the vertical drops in the drywell for the variable and reference legs are almost identical. Substantial errors can results from flashing at low pressure because the vertical drops in the drywell are approximately 12 feet. However, even for worst case conditions, the level instrumentation will sense increases or decreases in level when the indicated level is within the normal operating range. This is adequate to detect decreases in level to assure that the core remains covered with water. Therefore, there is no need to upgrade the instrumentation to reduce errors caused by high drywell temperature.

Concern 2

The applicant should evaluate the water level systems for Limerick to determine if operator action is needed to mitigate the consequences of a break in a reference leg and a single failure in a protection channel associated with an intact reference leg. If operator action is needed to mitigate the consequences of the cited event, the applicant should consider changing the protection system logic (for reactor trip and/or ESF system(s) actuation on reactor vessel low water level) so that this is accomplished automatically.

Evaluation

The Limerick logic design has four divisions and is comparable to plant B in SLI-8211. In the SLI-8211 review of plant B, there were no cases identified which failed to provide automatic reactor trip and ECCS actuation. Therefore, no changes are required for the Limerick protection system logic.

Concern 3

The applicant should identify the type of water level indication equipment used for Limerick. If the mechanical level indication equipment is used, the applicant should develop a plan for replacing it with analog level transmitters and trip units to reduce the vulnerability to failures or malfunctions.

Evaluation

Limerick uses electronic transmitters and solid state trip units. Therefore, this concern is not applicable to Limerick.

We have reviewed the concerns identified in SLI-8211 and we find that no changes to the Limerick water level instrumentation are required.

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

5 REACTOR COOLANT SYSTEMS

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.3 Reactor Coolant Pressure Boundary Materials (IGSCC)

The staff has reviewed the applicant's actions to mitigate intergranular stress corrosion cracking (IGSCC) of weld joints in stainless steel piping systems in our previous input to Section 5 of the SER. All weld joints of the primary coolant system stainless steel piping have been mitigated. For the other systems, the applicant has taken action to mitigate IGSCC in almost all weld joints, and has committed to take additional mitigating actions or augmented inservice inspection of those welds which have not been mitigated.

The applicant's surveillance program consists of: (a) regular monitoring of primary coolant chemistry to maintain conductivity and chlorides within Technical Specification Limits, (b) adding advanced analytical capabilities to monitor trace elements which are believed to have an effect on IGSCC, and (c) augmented inservice inspection of welds which have not been mitigated and are capable of being inspected. The applicant is also monitoring experimental activities of the Electric Power Research Institute, General Electric Co., and others concerning the effects of water chemistry on pressure boundary materials. The results of these studies will be reviewed for application to Limerick, and incorporated if appropriate.

The staff is preparing Revision 2 to NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping." It will address the staff's technical positions on material selection and processing for prevention of IGSCC in stainless piping systems and on inspections for those systems which do not conform to the technical positions on materials selection and processing. The staff anticipates that NUREG-0313, Revision 2, will be implemented uniformly on all BWR plants within 1 year.

At that time, the Limerick plants and all other BWRs which have not been reviewed in detail will be evaluated. The Limerick plants conform to the staff's technical positions in the proposed Revision 2 of NUREG-0313 on materials selection and processing to a greater extent than most operating BWRs. The Limerick plants have had little or no time at elevated temperatures, and accordingly, IGSCC has not occurred and is not anticipated to occur until at least the second refueling outage. On this basis Limerick Unit 1 is acceptable. Unit 2 will be addressed when Revision 2 to NUREG-0313 is implemented, which will be well before the unit's startup.

5.4 Component and Subsystem Design

5.4.7 Residual Heat Removal System

In its SER, the staff stated that the applicant must provide analyses for the proposed alternate shutdown cooling mode confirming that there is sufficient flow capacity in the alternate shutdown mode, and that RHR pump head-flow requirements would be satisfied for the worst path flow resistances.

The applicant provided the results of an analysis of the alternate shutdown cooling mode flow path as requested in a letter dated November 28, 1983. Standard engineering analysis methods were used, and the results provided in the letter indicate that accounting for frictional pressure losses, NPSH requirements for the pumps are satisfied for the worst path resistances, and there is sufficient flow for the alternate cooling mode. We have reviewed these results and conclude that they are acceptable. This confirmatory issue is closed.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Primary Containment Functional Design

6.2.1.3 Primary Containment LOCA Analysis

Environmental Qualification Envelope for Drywell (14)

In Section 6.2.1.3.3 of the SER the staff noted as a confirmatory issue its acceptance of the drywell environmental qualification envelope. This issue has been closed on the basis stated in Section 3.11.3.3.1 of this report.

6.2.1.7 Pool Dynamic Analyses

Bulk-to-Local-Pool Temperature Difference (15)

In Section 6.2.1.7.3(5)(C) of the SER, we stated that the applicant had committed to perform confirmatory analysis by using data from a comprehensive SRV in-plant test. This effort was to be done in accordance with NUREG-0783 recommendations. The objective was to establish the local to bulk pool temperature value and to demonstrate that the maximum local pool temperature specification would not be exceeded.

In revision 8 to the Design Assessment Report (DAR), the applicant indicated that the La Salle SRV test results are applicable to Limerick and that the suppression pool thermal mixing capability had been adequately assessed through the in-plant testing at La Salle and the associated analyses using the KFIX computer code, which were in conformance with NUREG-0763. The applicant concluded that the local pool temperature limits stipulated in NUREG-0783, for all plant transients involving SRV actuations will not be exceeded.

Our evaluation of the La Salle in-plant test data confirms the applicant's assumed bulk to local pool temperature difference used in the Limerick analyses. Our engineering judgement confirms the applicant's assertion on the applicability of the La Salle test data to the Limerick plant. However, the staff is still reviewing the KFIX Code which has been bench-marked using the LaSalle data. Nevertheless we find the above discussions to constitute an acceptable basis (in the subject area) for issuance of the full power license for the Limerick plant.

Wetwell-to-Drywell Vacuum Breaker and Downcomer Capping Adequacy Assessment (16)

In Section 6.2.1.7.3(6) of the SER we stated that the applicant had indicated that the four downcomers on which the wetwell/drywell vacuum breakers are mounted are being capped. This eliminates the effect of the chugging phenomenon on the vacuum breakers because capping the downcomers will eliminate the dynamic underpressure caused by the sudden steam condensation at the vent pipe exit and hence eliminate the vacuum breaker cyclic actuation. We have also stated in the SER that because of this design change, the applicant indicated that recalculations of the containment functional pressure analyses and pool swell loads were being done, but no changes in the safety margins that existed before capping of the downcomers are anticipated.

In Revision 6 to the Design Assessment Report, the applicant confirmed the previously stated conclusion by providing containment analyses based on 83 downcomers instead of 87 downcomers. We have reviewed the applicant analyses and agree with the applicant's conclusion that capping four downcomers has no adverse effect on the Limerick containment safety margins resulting from design bases LOCA loads and, therefore, we consider this issue to be resolved.

Anderson Greenwood Vacuum Breaker Test Program (17)

The LGS containment is equipped with simple, swing check valves to serve as vacuum breakers to equalize the pressure between the drywell and wetwell air space regions so that the reverse direction pressure across the diaphragm floor will not exceed the design value. The vacuum relief valves (four assemblies) are mounted on selected downcomers inside the suppression pool air space region.

Following the onset of a loss-of-coolant accident and during the pool swell phase, air flows from the drywell through the vent pipes and the suppression pool into the suppression pool chamber air space resulting in a rise of the suppression pool surface and compression of the air space region above it. This transient wetwell air space pressurization may cause the vacuum breaker valves to experience high opening and closing impact velocities. To estimate the valve disc actuation velocities, the Mark II Owner's Group developed a vacuum breaker valve dynamic model ("Mark II Containment Drywell-to-Wetwell Vacuum Breaker Models," General Electric Company Report No. NEDE 22178-P, August 1982) which was submitted for review by the staff.

The Containment Systems Branch (CSB) has completed its review of NEDE-22178-P, which describes the generic methodology used to calculate the response of the drywell-to-wetwell vacuum breaker to certain transients in the Mark II containment and found the approach acceptable.

The applicant indicated that use of this model will lead to predictions of very conservative impact velocities during pool swell transients since the hydrodynamic torque generated on the valve disc as a consequence of the pool swell differential pressure upstream and downstream of the valve very conservatively bounds full scale test data.

Recognizing the above, the LGS applicant along with the applicants for Shoreham and Susquehanna initiated an effort to predict more realistic yet conservative impact velocities for use in the qualification of the vacuum breaker valves.

During a meeting held on June 7, 1983 in Bethesda, Maryland between the staff and the applicants of Shoreham, Susquehanna, Limerick and WNP-2, a presentation was made of the analysis and redesign which produced a reduction in the valve impact velocities during pool swell. The material presented during that meeting is documented in a letter from DM O'Conner, Bechtel, to RW Houston, NRC, August 17, 1983, "AGCO Vacuum Breaker Test Program."

Reduction of the valve impact velocities during pool swell are attributed to the use of more realistic hydrodynamic torque on the valve disc. The applicant stated that the hydrodynamic torque specified in NEDE-22178-P is extremely conservative. Therefore, the applicant proposed a reduction of conservatism in the hydrodynamic torque as a function of valve opening angle and demonstrated that, even with the proposed reduction implemented in the model described in NEDE 22178-P, the predictions of disc impact velocity are conservative when compared with test data.

We have reviewed the applicant's submittals and conclude that the proposed reduction of the hydrodynamic torque is reasonable and, therefore, acceptable.

Several changes were made to the valve design, which contributed to a reduction of the impact velocities and to the strength of the valve for withstanding these impact velocities. The changes include:

> Redesign of the spring cylinder linkage (single bar linkage instead of 4 bar linkage); incorporation of an actuating cylinder (double cylinder modification) for damping; changes for a higher spring constant, thicker dome and ring flange; use of an internal stop; replacement of the shaft, keys, and pivot arm with higher strength materials; and a change to increase the shaft bearing area.

The predicted pallet impact velocities for the modified valve (using the dynamic model described in NEDE 22178-P, time dependent differential pressure loading across the vacuum breaker disc derived from the 4TCO test data and adjusted to a peak value of 5.5 PSID as recommended in NUREG-0808, and the mean hydrodynamic torque) are an opening impact velocity of less than 1 radian/sec and a closing impact velocity of 5.8 radians/sec.

The modified vacuum breaker was subjected to opening and closing impact velocities higher than the predicted impact velocities. Post-test visual inspection and leakage test show that valve operability and integrity as a pressure boundary are maintained and, therefore, the wetwell to drywell vacuum breaker valves will perform their function following the onset of a LOCA.

An analysis was performed for the Shoreham (opening impact velocity of 12.7 radians/sec and closing impact velocity of 10.9 radians/sec) modified vacuum breaker design to verify the valve's structural and pressure integrity. A linear elastic analysis was used for the evaluation of all valve components. An additional plastic analysis was performed to evaluate the structural integrity of the "spiders" for the pool-swell impact loadings. The "spiders" are spokes that are radially mounted on the valve disc and are designed as energy absorbing members to absorb the energy associated with the disc impact loads. The loads and load combinations were reviewed and found to be in accordance with staff's acceptance criteria. The loads were combined using the methodology in NUREG-0484 (Rev. 1), "Methodology for Combining Dynamic Responses."

The resulting stresses in the primary pressure retaining boundaries were within the ASME Class 2 faulted allowables (Service Level D). The resulting stresses in the shaft, linkage, and spring cylinder were within the ASME Class 2 emergency allowables (Service Level C). The structural integrity of the spiders were verified by comparing the calculated plastic strain with the strain corresponding to the allowable stresses as defined in Subparagraph F-1341.2 of Appendix F of the ASME Boiler and Pressure Vessel Code.

Based on the analyses performed by the Shoreham applicant which verified the valve structural and pressure integrity and test results which demonstrated the valve operability and functionality, the staff finds that the design of the modified vacuum breaker valves for LGS is acceptable and can accommodate the effects of pool swell impact loadings following a design basis LOCA. The staff conclusion is based on the analysis performed on the Shoreham valves which have the same modifications as LGS except for the additional actuating cylinder on the LGS valve for damping of the maximum impact velocity. Thus, the LGS valves will experience lower impact velocities and corresponding lower loads than the Shoreham valves.

6.2.1.8 Applicability of Mark III Concerns (18)

In Section 6.2.1.8 of the SER, we stated that we will report our final evaluation of the Mark III related concerns in a supplement to the SER prior to fuel load date. These Mark III related concerns were brought to the staff's attention via a letter from Mr. J. Humphrey, a former GE engineer, to the Mississippi Power & Light Company (MP&L).

As we stated in the SER, the design differences between the Limerick design and Mark III containment make many of the issues moot. However, the NRC is evaluating the applicant's response to all the concerns which were submitted in a letter from J. Kemper to A. Schwencer dated September 30, 1982.

On the basis of a preliminary assessment of the 23 major items (each with related subtopics) identified by Mr. Humphrey, the staff finds that all but one of these issues either were previously considered in some way by the applicant or do not represent safety concerns.

The one item among the 23 items that the staff believed warranted staff review is the response of the RHR system (when it is used in the steam condensing mode) and of nearby structures in the suppression pool to loads produced by the steam condensation phenomenon.

In regard to this item, the applicant stated in a letter from J. Kemper to A. Schwencer dated November 7, 1983, that the Limerick design has considered vent clearing, condensation oscillation (CO) and chugging loads produced by RHR heat exchanger relief valve discharges into the suppression pool. The applicant further stated that adequate design margins exist for the piping system to accommodate water clearing and CO/chugging tip loads.

Considering the applicant's response, it is the staff's preliminary assessment that these concerns have been adequately addressed by the applicant and do not represent safety concerns. The basis for our judgement is provided below.

1. Based on our review of the issues, we have concluded that they were considered in the design of the Limerick containment; we have not, to date, uncovered any deficiency in the containment design;

2. Design differences between Limerick's Mark II containment and the Mark III containment make many of the issues not pertinent to Mark II containments; and

3. The staff's preliminary evaluation of the applicant's response, in the letters from J. Kemper to A. Schwencer, dated September 30, 1982, and November 7, 1983, confirms the applicant's assertion that they have not identified any design deficiency.

On these bases the staff concludes that these issues have been acceptably resolved for operation at full power. The staff will be continuing its review of the applicant's submittal on these issues to confirm the preliminary assessment reached above. In the near term, the review will focus principally on resolution of these issues for the Mark III plants, to be followed at a later time by a review of the issues on the Mark I and the Mark II plants.

6.2.3 Secondary Containment Functional Design (SGTS)

The secondary containment for Limerick, Unit 1, consists of the reactor enclosure zone and the refueling floor zone. According to FSAR Sections 6.2.3 and 6.5.1.1.1, the SGTS is needed to maintain a 0.25 in wg vacuum in each zone during secondary containment isolation conditions. This vacuum, along with the effluent treatment features of SGTS, mitigates offsite releases during either a LOCA or a fuel handling accident. However, the SGTS connection to the refueling floor zone will not be completed until the first refueling outage. This issue is also discussed in Section 9.4.2 of the FSAR. The applicant indicated that the refueling floor zone is completely isolated from the Unit 1 secondary containment zone and that the refueling floor zone is only relied upon during fuel handling. The applicant further stated that since there would be no irradiated fuel in the spent fuel pool until the first refueling outage, deferral of connecting the SGTS to the refueling floor volume is justified.

The staff agrees with the applicant's rationale; however the operating license for the Limerick Generating Station will be conditioned to require connection of the refueling floor zone to the SGTS prior to the movement of irradiated fuel. Furthermore, the applicant will not be permitted to remove the RPV head during this interval prior to staff evaluation and approval.

6.2.4 Containment Isolation System

Procedure for Isolating Feedwater Bypass Lines (19)

In Section 6.2.4.1 of the SER, we indicated that automatic isolation of the feedwater bypass lines is not required if the applicant instituted operating procedures for alerting the operator of the need to isolate these bypass lines and to seal them closed once the reactor pressure is above 600 psig.

In its letter dated May 25, 1984, the applicant stated that Procedure No. GP-2, Revision 0, "Procedure for Normal Plant Startup" includes a step to ensure closure of the feedwater startup flush valves (feedwater bypass valves) whenever reactor pressure is above 600 psig. Based on our evaluation of the applicant submittal, we find it acceptable, and therefore, this issue is closed.

6.2.5 Combustible Gas Control System

Procedures for Hydrogen Recombiner Operation (20)

Section 6.2.5 of the SER states that the staff will require the applicant to have operating procedures that ensure that initiation of the hydrogen recombiner system does not create a steam bypass path that could cause the containment design pressure to be exceeded.

In a letter dated June 27, 1984, from J. Kemper to A. Schwencer, the applicant stated that the subject concern is addressed in Section 7.2 of Procedure No. S58.1.B, Revision 1: Start-Up of a Containment Hydrogen Recombiner from the Standby Condition or Following a Trip. In these operating procedures, the operator is instructed not to place the hydrogen recombiners in service until the reactor has been depressurized following onset of an accident.

Based on the staff's review of the applicant's submittal, we conclude that appropriate operating procedures are in place to preclude the initiation of the hydrogen recombiner system during situations that might create a steam bypass of the suppression pool. Therefore, this confirmatory issue is closed.

Procedures for Type "A" Leak Testing for Hydrogen Recombiners and Combustible Gas Analyzers (21)

In Section 6.2.5 of the SER, we requested the applicant to submit the specific testing procedure on the hydrogen recombiner and the combustible gas analyzers for Type A containment leakage testing.

In its letter dated April 30, 1984, the applicant stated that Preoperational Test Procedure No. 1P-59.2, Revision 0, "Preoperational Primary Reactor Containment Integrated Leak Rate Test Procedure", implements specific procedures for Type "A" containment leakage testing of the hydrogen recombiner and analyzer systems to assure the leaktight integrity of these systems.

This procedure has been reviewed and found acceptable. Based on the information contained in the applicant's submittal, we conclude that this issue is now closed.

6.3 Emergency Core Cooling System

6.3.5 Performance Evaluation

Procedures for Response to LOCA (23)

The SER stated that the acceptability of the applicant's assumption of certain operator actions in 10 minutes for response to LOCA was dependent on the staff's review of TMI Action Plan Item I.C.1 regarding such procedures.

Two postulated accidents were identified by the applicant where credit was taken for operator action in the accident analyses at 10 minutes: manual initiation of suppression pool cooling during a design-basis LOCA, and manual depressurization of the reactor coolant system for a main steamline break outside of containment. The assumed startup of suppression pool cooling at 10 minutes has been accepted by the staff for previous applications because of the simplicity of the required operator actions. We have reviewed the corresponding sequence of operator actions for Limerick and conclude that it is reasonable to assume that these actions could be completed within 10 minutes.

Regarding main steamline breaks outside of containment, the planned modification to the ADS logic described in SER Section 15.9.4 has been implemented, and this modification eliminates the need for manual depressurization during these events.

In addition, the staff has performed a review of the Limerick emergency procedures and has determined that the applicant has satisfied Item I.C.1 regarding LOCA procedures in that they are based on Emergency Procedure Guidelines that have been reviewed and approved by the staff. We conclude that this issue is closed.

Plant Specific LOCA Analysis (24)

The staff's SER reported the results of a lead plant LOCA analysis that was stated by the applicant to be representative of Limerick. The SER also noted that the applicant had committed to supply a plant specific LOCA analysis for Limerick before fuel loading.

The applicant provided a plant specific LOCA analysis in FSAR Revision 30 dated March, 1984. The plant specific LOCA analysis included a spectrum of large and small pipe breaks and indicated that the most limiting break is a design-basis break in a recirculation suction pipe. Just as it was for the lead plant analysis, an assumed failure of the Division 2 emergency dc power source coincident with the break, resulted in the worst single failure condition for Limerick. The plant specific results demonstrate compliance with the requirements of 10 CFR 50 as follows:

Criterion	Maximum value from analysis	Allowable
Peak Cladding Temperature (PCT)	2090°F	2200°F
Maximum Cladding oxidation	1.7%	17%
Maximum total hydrogengeneration	0.11%	1%

From our review, we conclude that the plant specific LOCA analyses for Limerick are acceptable. This confirmatory issue is closed.

Core Spray Distribution Tests (25)

The Limerick SER discussed core spray distribution test results and indicated that further review would be performed. Additional background on this issue and the specific conclusions for Limerick are as follows.

In 1981, a test of core spray distribution in steam conducted in a foreign country raised concern that the central fuel bundles of a BWR/5 core may receive low spray water flow. The NRC staff notified Licensing Boards (Board Notification BN-81-49) of this concern and further pursued the matter to obtain more detailed information about the foreign tests via the international information exchange program. In 1982, the staff received and reviewed the foreign test report. The tests were conducted in a 60 degree sector steam test facility for a simulated BWR/5. The results indicate that the flow of water to the fuel bundles decreases as the distance from the center of the core decreases and results in a minimum flow of about 1.5 gpm at a radius of approximately 5 inches from the center of the core. The available data do not provide information showing the core spray flow rate to the central fuel bundles. The minimum bundle flow obtained from the available data is greater than the bundle flow of one gpm required to justify the heat transfer coefficient of 1.5 Btu/hr-ft^2 °F for core spray cooling employed in the GE ECCS Evaluation Model. However, because of concern about the spray distribution to central bundles, the staff required GE to analyze the limiting LOCA for BWR/4 and BWR/5 cores to evaluate the effect of no core spray cooling on the peak cladding temperature.

During core spray injection, water will either be distributed to the core or bypass the core and drain to the lower plenum region. The latter case results in a rapid bottom reflood rate. Presently, credit is not taken for this rapid bottom reflood effect in the GE ECCS Evaluation Model. Any liquid accumulated at the top of the tie plate before exceeding the counter-current flow limit is assumed to be discharged from the system and does not contribute to the reflood. Tests for the 30 degree steam sector evaluation of ECCS mixing phenomena performed in the GE Lynn facility in 1981 (NUREG/CR-2786) show that spray flow injected into the upper plenum drains to peripheral bundles and increases the bottom reflood rate. In response to the staff request, GE presented analytical results based on a model which assumes that the core spray coolant drains through the peripheral channels to the lower plenum, thus increasing the reflood rate as observed in the Lynn tests. The calculated peak cladding temperature using this model based on experimental data, but with no credit taken for the spray cooling effect (i.e., the heat transfer coefficient for spray cooling is assumed to be zero), did not exceed the 10 CFR 50.46 temperature limit of 2200°F. Therefore, in the safety evaluation report (NUREG-0420), the staff concluded that the core spray distribution does not pose a safety concern for BWR/4 and BWR/5 cores.

Since the conclusion in NUREG-0420 is applicable to Limerick, we conclude that this confirmatory issue is closed.

6.5 Engineered Safety Feature Atmospheric Cleanup System

6.5.3.2 Standby Gas Treatment System

In the SER, we indicated that a demister was included among the components of each standby gas treatment system (SGTS) train. In the FSAR, Revision 25, the applicant indicated that the demisters would not be included and that prefilters would be provided instead. The applicant's position is that a demister is not required because the absence of water droplets in the air stream entering the SGTS filters during refueling area isolation, primary containment purging, and post-LOCA isolation is assured.

There are no sources of water droplets in the refueling area which could enter the duct connection with the SGTS. If condensation does occur in the ducts, the amount would be determined by heat and mass transfer characteristics or the amount of water vapor in the air stream, whichever is the more limiting. Condensation is drained from low points in the duct. Entrainment of condensation from the surface of the duct is insignificant due to the low air velocities in the duct during and after the time when condensation might be significant. The tortuous flow path and the insulated upward leg of the duct in the control enclosure will remove any remaining large water droplets from the air stream. The SGTS heaters will remove any remaining small water droplets and reduce the relative humidity to 70%.

It is unlikely that water droplets will enter the purge lines during primary containment purging, using the SGTS, because of the preventative maintenance program, the distance between postulated leaking valves and the suppression chamber purge exhaust opening, and the limited period of purge system usage during power operation (typically less than 90 hours per year). If droplets enter the ducts, or if condensation occurs within the ducts, the water droplets will not reach the SGTS filters because of the tortuous flow path, the insulated ductwork in the control structure, and the SGTS heaters. Only surface condensation will occur in the ductwork, much of which will be removed by drains at low points. However, due to the high air stream velocities, it is possible for some water droplets to be entrained in the air stream. Water droplets greater than 20 microns in diameter will be removed by the bends and turns, acting like a coarse moisture separator. Water droplets less than 20 microns in diameter may reach the SGTS heaters. The heaters are capable of evaporating all droplets less than 25 microns in diameter before they reach the HEPA filters. Even if all of the condensation that forms in the duct reaches the HEPA filters as water droplets, the loading rate is below the rate where plugging of the filters will occur. The SGTS heaters are capable of removing the entrained droplets and reducing the relative humidity to 70%.

The SGTS intake is downstream of the reactor enclosure recirculation system (RERS) filter during post-LOCA isolation so that entrained droplets cannot enter the SGTS filters during post-LOCA isolation and drawdown. The absence of water droplets in the RERS air stream during reactor enclosure isolation is assured because of the preventative maintenance program to control leakage, the 0.5%/day of air leakage imposed by the containment technical specification, the distance between a postulated failed RHR pump seal and the local RERS exhaust vents, the condensation of water vapor by the RHR room coolers, the tortuous and upward path of the ductwork, and the dilution of the small air flow from the RHR room with air from other parts of the reactor enclosure.

The applicant has stated that if a LOCA occurs while the purge system containment isolation valves are open, it is possible that the SGTS filters could be damaged by the pressure surge preceding valve closure or by the moisture content of the released gases. Because containment purging during normal operation is limited to 90 hours per year, the impact on plant risks resulting from a LOCA while purging and the potential for failure of the SGTS contribute little to the likelihood of an uncontrolled radioactive release. Therefore, we conclude that a demister is not needed to protect the SGTS filters from moisture in gases released from a LOCA during primary containment purging.

Based on our review, we conclude that a demister is not needed in the SGTS because assurance otherwise has been provided that water droplets will be absent in the air stream entering the SGTS filters at all times when the SGTS filters are needed to mitigate the consequences of postulated accidents.

7 INSTRUMENTATION AND CONTROLS

7.2 Reactor Trip Systems

7.2.2.2 Failures in Reactor Vessel Level Sensing Lines

In the SER the staff evaluated the effects of instrument sensing line failures on the automatic reactor trip and ESF actuation system. The subject sensing lines are common to feedwater control, reactor trip sensors and ESF sensors. The SER also noted that the staff was expecting further information from the applicant to confirm that no adverse consequences with respect to core cooling would result from reactor vessel level sensing line failures. This confirmatory issue was dependent upon the resolution of issues identified in Section 4.4.7 of the SER.

The staff has completed its evaluation of this issue as reported in Section 4.4.7, item 2, of this report and finds that no changes to the Limerick protection system logic are required. This confirmatory issue is therefore closed.

7.2.2.9 Isolation of Circuits

In the SER the staff evaluated isolators used to maintain independence between redundant Class 1E circuits and between Class 1E and non-Class 1E circuits and noted that the staff would confirm successful completion of tests and the adequacy of (1) GE isolators for the redundant reactivity control system and (2) the Love Model 106 process signal converter-isolator.

The staff has completed its review of information provided by the applicant in letters dated December 4, 1983 and June 7, 1984 on this subject. Those letters provided the information requested by the staff and this confirmatory issue is therefore closed.

7.2.2.10 APRM Upscale Trips

The SER noted that the information originally provided in FSAR Chapter 7 contained discrepancies regarding the average power range monitor (APRM) upscale trips.

The applicant has revised FSAR Chapters 7 and 15 to correct the discrepancy regarding the APRM input to the reactor trip system. This confirmatory issue is therefore closed.

7.3 Engineered Safety Features Systems

7.3.2.5 Manual Initiation of Safety Systems

In the SER the NRC staff identified a concern regarding the design of the electrical interlocks on the core spray, containment spray and low pressure coolant injection isolation valves. During the NRC staff's review, it was determined that certain core spray, (CS) containment spray (CS-RHR) and low pressure coolant injection (LPCI) systems valves share common interlocks between the automatic and systems level manual initiation circuits. RG 1.62, "Manual Initiation of Protective Action," provides guidance on the acceptability of such designs and recommends that an independent manual initiation capability, at the component level, be provided in the control room.

The CS and LPCI systems are initiated automatically by a LOCA signal (low reactor water level and/or high drywell pressure with low reactor pressure) or by system level remote-manual switches. Components of the CS and LPCI systems can also be operated individually via remote-manual switches. For automatic or system level manual initiation of the CS and LPCI systems, interlocks sensing power availability on the pump motor bus must be satisfied. In all three initiation modes (automatic, system level manual, and component level manual) injection valve operation depends on satisfying common interlocks sensing pressure.

There are four LPCI loops--A, B, C, and D. Each LPCI loop injection valve cannot be opened unless the interlock sensing low differential pressure across the valve is satisfied. Four separate sensors and trip units are provided, one for each loop, arranged in a one-out-of-one logic. There are two CS loops--A and B. Each CS loop includes a normally closed inboard injection valve and a normally open outboard injection valve. Four separate sensor and trip units are arranged in a one-out-of-two-taken-twice logic to provide a permissive for opening the valves on low reactor pressure. The inboard and outboard valves are interlocked by a limit switch to prevent both valves in each loop from being opened manually at the same time during testing.

The containment spray mode of RHR (CS-RHR) (two loops) is placed in operation manually from the control room by opening the two injection valves in each loop when the LPCI pumps A and B are in operation. Each containment spray loop is initiated manually by means of two remote manual switches, one for each injection valve. Both injection valves in a loop may be opened if a LOCA signal is present, if the drywell pressure is high, and if the LPCI injection valve for that loop is closed. If any one of these three required permissives is missing, the valves are interlocked closed. The valves can be opened one at a time for testing.

From additional review of the designs, the staff has confirmed that on a systems level each CS, LPCI and CS-RHR loop is assigned to a separate electrical division. Logic and motive power for each division is supplied from safeguard power sources within the division, and each safety division is separated from each of the other safety division. A single loop of the CS, LPCI or CS-RHR in itself is not designed to sustain a single failure and still perform its design function. Single failures such as a loss of one division of safeguard power, logic failure in one division, or an instrument failure in one division can disable one loop. From a detailed review of the interlock circuitry and an assessment of the reliability of the components common to automatic, systems level manual and individual component level manual initiation, the staff has found no evidence to support a conclusion that the failure of common interlock components is more probable than other disabling failures. In response to a request from the NRC staff, the applicant has confirmed that the "worst case" single failure analysis for a design basis accident included consideration of the common interlock circuitry.

Although modifications to provide independent interlock circuitry for automatic, systems level manual, and component level manual initiation would eliminate one potential disabling single failure for each loop, the NRC staff finds that such changes cannot be justified on a cost benefit basis. However, the consequences of such a single failure in one loop coupled with a design basis accident can be acceptably mitigated with redundant component and systems in the other loop. In summary, the NRC staff finds that the applicant's position to retain the present CS, LPCI and CS-RHR interlock design is acceptable, and, therefore considers this item resolved for Limerick.

7.4 Systems Required For Safe Shutdown

7.4.2.1 Capability for Safe Shutdown Following Loss of Electrical Power to Instrumentation and Controls (IE Bulletin 79-27)

In the SER the staff noted that the applicant had analyzed alarms and/or indication provided in the control room to alert the operators to loss of power to instrumentation and control systems and that the staff would confirm the adequacy of the alarms following receipt of the design details.

By letter dated December 14, 1983 the applicant provided a revised response to IE Bulletin 79-27 which included the additional information regarding the direct and indirect indication of power loss and therefore this confirmatory issue is closed.

7.7 Control Systems

7.7.2.1 High-Energy-Line Breaks and Consequential Control Systems Failures (IE Information Notice 79-22) and Multiple Control System Failures

In the SER the NRC staff addressed a concern raised in IE Information Notice 79-22. The concern relates to control systems that are exposed to the adverse environment caused by a high-energy-line break (HELB). The systems may malfunction in a way that could cause consequences more severe than those assumed in the safety analysis of the FSAR. In response to the NRC staff's concern, the applicant conducted a study to examine the possible effects that adverse environmental conditions may have on nonsafety-related instrumentation and control systems. By letter dated May 4, 1984, from J. S. Kemper (Philadelphia Electric Company) to A. Schwencer (NRC), the applicant provided a report documenting the analysis performed to address this issue.

To resolve this concern, the applicant identified the nonsafety-related control systems which could impact critical reactor parameters (i.e. waterlevel, pressure, critical power ratio) and the location of high energy lines; and determined the effects of postulated HELBs with potential simultaneous malfunctions of adjacent control systems components. The combined effects of the HELB and control system malfunctions were then compared with the transient and accident analyses contained in the FSAR.

The scope of the HELB analysis was limited to nonsafety-related control systems components judged to have an influence on critical reactor parameters. In general, initiating type control components such as elements, switches, transmitters, controllers and converters were included in the analysis, along with their related taps and process tubing. The criteria used for determining high-energy lines for this study were based on the criteria provided in the NRC's Standard Review Plan (NUREG-0800), Section 3.6.2 "Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping." High-energy piping is defined as piping where the contained gas or fluid's maximum operating temperature exceeds 200°F or where the maximum operating pressure exceeds 275 psig. A zone concept was used in the Turbine and Reactor Enclosures to separate the plant into definable sections for the purpose of this study. A plant walkdown was performed in connection with this study to accurately define zones, verify the location of control system components, and to assess the proximity of the components, associated taps and tubing to the high-energy lines.

Postulated piping failures for each high-energy line in the zone were examined in combination with the resulting "worst case" failures of control systems components in the zone to determine if any combination of possible failures resulting from pipe whip, steam jet impingement or adverse environment could exacerbate the effects of the HELB. When safety-related systems were initiated to mitigate the event, an additional single active failure was considered.

From a review of the results of the study the NRC staff finds that, in most cases, the effects of the postulated HELB and control systems failures events are less severe than the Unacceptable Results for Incidents of Moderate Frequency-Anticipated Operational Transients as presented in the FSAR. In all cases, the effects of the postulated events are bounded by the Unacceptable Results of Limiting Faults-Design Basis Accidents, as presented in the FSAR. On this basis, the NRC staff finds the safety-related and nonsafety-related systems response to a HELB acceptable and, therefore, considers this item resolved for Limerick.

In the SER the NRC staff addressed a concern regarding multiple control systems failures. If several control systems or control and safety systems are supplied information from a common source (including sensors, taps, headers or instrument lines) or are supplied from a common power source, a failure of the power source or common information source instrument line could cause multiple control systems failures. Such failures are not addressed in the FSAR and may not be bounded by the FSAR's safety analyses. By letters dated December 14, 1983, and June 5, 1984, from J. Kemper (Philadelphia Electric Company) to A. Schwencer (NRC), the applicant provided an analysis of the consequences of multiple system failures resulting from failures of a sensor, tap, header, instrument line or power source.

To resolve this concern, the applicant identified the control systems which could impact critical reactor parameters (i.e. water level, pressure, critical power ratio) with shared sensors, power supplies or instrument piping and determined the "worst case" failure modes. The bounding failures for instrument piping were an instantaneous break or plug in a line. For this evaluation a broken line to a pressure transducer resulted in a sensed low pressure condition. A broken line to a differential pressure transducer resulted in maximum differential pressure if the reference leg line is broken and minimum or negative differential pressure if the variable leg line is broken. A broken line to a differential pressure transducer used as a liquid level sensor results in an indicated high water level if the reference leg is broken and a low level indication if the variable leg is broken. Plugged lines were considered to be 100 percent plugged, causing sensors to be inaccurate under changing pressure conditions.

No new transients were identified as a result of this analysis, and the consequences of the identified failures are bounded by the FSAR accident and transient analyses. In addition, this analysis has determined that neither the required separation between the control and protective systems nor the required redundancy of the protection systems could be defeated by a failed common instrument line. The NRC staff has reviewed the assumptions, methodology and results of the applicant's study. Based on this review, the NRC staff finds the shared design configuration of certain power sources, sensors and instrument piping acceptable and, therefore, considers this item resolved for Limerick.

7.7.2.2 Rod Sequence Control System, Rod Worth Minimizer and the Rod Block Monitor

In the SER the staff indicated that it would confirm that FSAR Chapter 15 was revised to include the results of the applicant's analyses of postulated RSCS, RWM and RBM failures. The staff concluded in the SER that the failure of these nonsafety-related systems would not pose a threat to safety.

A revision to the FSAR has incorporated the analysis of the postulated failures of these systems and therefore this confirmatory issue is closed.

9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling

9.1.3 Spent Fuel Pool Cooling and Cleanup Systems

In our SER the staff stated that the spent fuel pool cooling system would maintain the fuel pool water temperature at 130°F, with a heat load of 16.1 MBTU/hr based on the decay heat generation from 2862 fuel bundles (maximum storage capacity of the pool assuming that the entire pool was filled with racks that are identical with those presently in the pool) and with two cooling trains in operation. The maximum acceptable water temperature as stated in the SRP is 140°F for normal heat loads. The fuel pool water temperature should have been identified as 138°F (instead of the 130°F) for the 16.1 MBTU/hr heat load. Based on independent staff calculations this heat load would be associated with a maximum number of 2484 fuel bundles. Section 9.1.2 of the SER stated that the applicant has currently provided storage racks for a maximum of 2040 fuel bundles.

The staff conclusions as stated in the SER are therefore revised to the extent that the staff finds acceptable the currently proposed and installed capacity of 2040 fuel bundles, which is less than the 2484 that corresponds to a pool water temperature of 138°F.

9.1.4 Light Load Handling Systems (Related to Refueling)

In our SER we stated that the refueling platform has redundant interlocks and limit switches to prevent accidental collision with the walls of the spent fuel pool. Based on the applicant's recent submittal we now believe that this statement could be misinterpreted. All safety-related interlocks are redundant to meet the single failure criterion. The limit switches, which are not safety-related, are not redundant and therefore do not meet the single failure criterion. The fuel grapple hoist of the refueling platform is safety-related and therefore has redundant load handling components. This reduces the possibility of dropping a fuel bundle or striking the pool wall. The nonsafety-related limit switches on the refueling platform prevent collision of the fuel bundle with the pool wall while being transported by the refueling platform. The effects of the collision with the pool wall would be bounded by the consequences of the fuel handling accident reviewed in Section 15 of the SER, thus having nonsafety-related, nonredundant limit switches is acceptable. This clarification does not affect our conclusions as stated in the SER.

9.2 Water Systems

9.2.2 RHR Service Water System

In our SER we stated that the Unit 2 RHR Service Water (RHRSW) pumps which are part of the Unit 1 RHRSW system will be powered from the Unit 1 diesels C and

D until Unit 2 receives its license. The SER should have stated that the Unit 2 RHRSW pumps would be powered only from offsite power until Unit 2 receives its license. As both Unit 1 RHR pumps, piping and valves will be available the clarification regarding the Unit 2 RHR pumps will not change our conclusions in the SER.

9.3 Process Auxiliaries

9.3.1 Compressed Air Systems

In our SER we stated that three micron filters would be installed at the interconnection between the instrument air system and the primary containment instrument gas (PCIG) system to meet the ANSI MC 11.1-1976 standard. The three micron filter is to remove all particulates three microns and larger from the instrument air when the instrument air is used as a backup for the PCIG to prevent particulate buildup at safety-related pneumatic components, normally served by the PCIG, and thereby reduce the potential failure rate of these components.

By letter dated May 16, 1984, the applicant stated that the air systems serves only equipment supplied by General Electric. General Electric stated that an air quality of no visible particulates for the safety-related components served by the PCIG will ensure long term reliable operation of the equipment. Visible particulates have been defined by General Electric as particles of 50 microns or larger. The applicant has proposed a maximum particulate size of 40 microns.

Based on the 40 microns being smaller than the General Electric equipment requirements of 50 microns, the use of 40 micron filtered air is acceptable. This change in the maximum particulate size does not affect our conclusions as stated in the SER.

9.3.2 Process Sampling System

Item II.B.3 - Postaccident Sampling System

As stated in the SER, NUREG-0737, Item II.B.3, Postaccident Sampling System (PASS), requires an applicant to provide a capability to obtain and quantitatively analyze reactor coolant and containment atmosphere samples, without radiation exposure, to any individual exceeding 5 rems to the whole body or 75 rems to the extremities (GDC 19) during and following an accident in which there is core degradation.

The staff concluded in the SER that the Limerick PASS was acceptable when reviewed relative to 10 of the 11 criteria of Item II.B.3. The core damage estimation procedure (in response to criterion 6) had not been submitted at the time of preparation of the SER. By letter of April 2, 1984, and Exhibit No. 6 (procedure EP-326) of the applicant's testimony filed on April 2, 1984, relating to onsite emergency planning contentions, the applicant provided additional information. The applicant also provided by letter of July 6, 1984, a description of a modification which provides for a dissolved gas measurement capability.

EP-326 is a procedure for estimating core damage during accident conditions based on the generic BWR Owners Group procedure of June 17, 1983. The Core

Physics Coordinator has the responsibility to determine the extent of core damage utilizing this procedure. Core damage estimates are based on utilizing postaccident sampling system measurements on iodine-131 concentration in primary coolant and xenon-133 concentration in containment. Additional procedures are provided for estimating the extent of metal-water reaction based on measured hydrogen concentration in containment and for estimating the extent of core damage based on containment radiation monitors. This meets criterion 6 and is, therefore, acceptable.

The staff also finds that the information presented in the letter of July 6, 1984, on the modified dissolved gas measurement capability is consistent with the evaluation and conclusions already reached in the SER.

On these bases the staff concludes that the Limerick postaccident sampling system meets all of the requirements of Item II.B.3 of NUREG-0737 and is, therefore, acceptable. Since reactor criticality and operating conditions are needed to demonstrate operability of the PASS, a condition to the license will require that prior to exceeding 5 percent power operation the applicant shall have installed and demonstrated the operability of the system.

9.4 Heating, Ventilation and Air Conditioning Systems

9.4.5 Engineered Safety Feature Ventilation System

9.4.5.1 Nitrogen Inerting System IE Notice No. 84-17

IE Information Notice No. 84-17 describes problems which could possibly occur on BWR plants that have nitrogen inerting systems. The notice describes the through wall crack discovered in the vent header within the containment torus at Hatch Unit 2 caused by cold nitrogen impinging on the vent header and cooling it below the nil-ductility temperature. The crack degraded the containment pressure suppression capability of Hatch 2, and raised a possible generic concern for other BWR plants which utilize similar containment and inerting system designs.

The containment inerting system is designed to inject nitrogen gas into the wetwell so as to limit the oxygen concentration in containment to less than approximately 4% by volume. 10 CFR Part 50.44 requires, in part, that plants with the Mark II containment, such as Limerick, shall have an inerted containment atmosphere by 6 months after initial criticality.

The containment atmosphere inerting system for Limerick is described in Section 9.4.5.1 of the FSAR. The liquid nitrogen (LN) is passed through a steam-heated water bath vaporizer into the containment. A low temperature cut-off switch is provided to cut off the LN supply if the nitrogen gas temperature, as it leaves the vaporizer, is less than 50 degrees F. The staff has reviewed this system during its normal review of the FSAR. However, our review did not include consideration of postulated failures of either the vaporizer or the cut-off switch.

The nitrogen inerting system utilized in the Limerick design is basically similar to that utilized at Hatch-2; thus it would appear that the same failures, which led to the Hatch-2 incident, could also occur at Limerick. We believe that proper calibration, maintenance, and operation of the system will reduce their likelihood of occurrence to an acceptably low level. We intend to pursue this matter during our continuing review of the inerting system.

Finally, there are some other design differences between Limerick and Hatch-2, which make this issue a far smaller concern. Among these differences are:

1. The Limerick design does not have the vent header which incurred the crack at Hatch-2;

2. The nitrogen injection port is not directly on top of or nearby any safety related equipment. The injection port is flush with the containment wall, the closest downcomers are 6 feet off center;

3. The containment inerting atmosphere is not needed prior to at least 6 months after initial criticality.

For the reasons set forth above, we conclude that adequate bases exist to proceed with licensing of the Limerick Generating Station.

9.5 <u>Other Auxiliary Systems</u>

9.5.1 Fire Protection

At our request, by letters dated November 23, 1983, February 16, 21 and 29, June 21 and August 8, 1984, Fire Protection Evaluation Report Amendments 3, 4, 5 and 6 and through FSAR Amendment 34, the applicant provided additional information concerning 1 open item and 28 confirmatory items identified in our SER. Our evaluation of this information is incorporated in the following revised SER paragraphs.

9.5.1.1.1 Fire Protection Program

By FPER Amendment 4, the applicant committed to comply with our guidelines in BTP CMEB 9.5-1, Section C.1.a.

Based on our review, we find that, with this commitment, the fire protection program meets the guidelines of BTP CMEB 9.5-1, Section C.1, and is, therefore, acceptable.

9.5.1.1.2 Fire Hazards Analysis

The applicant's fire hazards analysis specified the combustible materials present in fire areas, identified safety-related equipment, determined the consequences of a fire on safe shutdown capability, and summarized available fire protection in accordance with BTP CMEB 9.5-1, Section C.1.b. Our evaluation of the identified fire hazards is in the paragraphs below. Alternative shutdown capability has been provided for the control room and cable-spreading room; this capability also is evaluated below.

GDC 3 requires that fire fighting systems be designed to ensure that rupture or inadvertent operation does not significantly impair the safety capability of structures, systems, and components important to safety. To satisfy this requirement, the applicant has designed components required for hot shutdown so that rupture or inadvertent operation of fire suppression systems will not adversely affect the operability of these components. Where necessary, appropriate protection is provided to prevent impingement of water spray on components required for hot shutdown. Redundant trains of components that are susceptible to damage from water spray are physically separated so that manual fire suppression activities will not adversely affect the operability of components not involved in the postulated fire.

Automatic suppression systems have been designed and located so that operation of the systems, either intentional or inadvertent, will not cause damage to redundant trains of safety-related equipment that is needed for safe shutdown of the plant. Components that are needed to achieve safe shutdown which are located within automatic suppression system coverage zones are designed to remain functional in the event of suppression system actuation.

Three of the areas that are provided with automatic water-type suppression systems are the HPCI pump compartment, the RCIC pump compartment, and the diesel generator cells. Actuation of the suppression systems in the HPCI and RCIC pump compartments could cause damage significant enough to affect the operability of the systems in those compartments. In the diesel-generator cells, baffles are provided to protect the generators and control devices from damage due to suppression system actuation, but each diesel-generator will be automatically tripped if the suppression system in its cell is actuated. Loss of any of these three systems due to suppression system actuation is acceptable, because other redundant systems are available to bring the plant to safe shutdown.

The electrical interconnections between the individual diesel-generators and their respective suppression systems represent the only case in which safe shutdown components have electrical interconnections with fire detection or fire suppression systems. Therefore, safe shutdown components other than the individual diesel-generators cannot be inadvertently actuated or shutdown due to either normal or abnormal signals in the control and power circuits of the fire detection and fire suppression systems.

The HPCI and RCIC pump compartments and the diesel-generator cells are the only safety-releated areas of the plant that are provided with automatic suppression systems and also are potentially subject to steam flooding as a result of high-energy pipe breaks. Elevated compartment temperatures due to steam flooding could result in suppression system actuation if the temperatures are high enough to cause the deluge valve to open. However, loss of the HPCI system, RCIC system, or a single diesel-generator due to suppression system actuation is acceptable, because other redundant systems are available to bring the plant to safe shutdown.

Based on our review, we conclude that the fire hazards analysis meets the guidelines in Section C.1.b of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.2 Admininstrative Controls

The administrative controls for fire protection consist of the fire protection program and organization, the fire brigade training, the controls over combustibles and ignition sources, the prefire plans and procedures for fighting fires, and quality assurance. By letter dated February 21, 1984, the applicant committed to meet the guidelines in Section C.2 of BTP CMEB 9.5-1. We find that, with this commitment, the administrative controls meet the guidelines in BTP CMEB 9.5-1, Item C.2, and are, therefore, acceptable.

9.5.1.3 Fire Brigade and Fire Brigade Training

By FSAR Amendment 17, the applicant committed to meet the guidelines contained in BTP CMEB 9.5-1, Section C.3. We find that, with this commitment, fire brigade and fire brigade training meet BTP CMEB 9.5-1, Item C.3, and are, therefore, acceptable. Fire brigade training is evaluated in Section 13.2.2 of this report.

9.5.1.4 General Plant Guidelines

9.5.1.4.1 Building Design

Fire areas are defined by walls and floor/ceiling assemblies. Walls that separate buildings and walls between rooms containing safe shutdown systems are 3-hour-fire-rated assemblies. In cases where the fire rating is less than 3 hours, we have evaluated each area with respect to its fuel load, fire suppression and detection systems, and proximity to safe shutdown equipment and concluded that the fire-rated assemblies provided are adequate for the areas affected and meet the guidelines in Section C.5.a of BTP CMEB 9.5-1.

In some fire areas, the applicant did not provide protection of structural steel members which support fire rated assemblies in accordance with our guidelines.

By letter dated February 24, 1984, the applicant submitted an analysis which uses a mathematical model to calculate the time-temperature profile for potential fires in each fire area.

If any of the calculations show that the time-temperature profile in an area will exceed 1100°F within 3 hours, an evaluation is performed to calculate the corresponding temperature response of the supporting structural steel. If the steel temperature exceeds 1100°F within 3 hours, the applicant has committed to protect the steel with 3-hour rated barriers where possible; however, in some areas where congestion prevents the effective application of insulating materials to the structural steel, the applicant will provide an automatic sprinkler system as an alternative form of protection. If the steel temperature does not reach 1100°F, the steel will not need to be protected. We find these criteria will provide an adequate level of fire protection, and therefore find them an acceptable deviation from our guideline.

Our consultant, Brookhaven National Laboratory, has reviewed the applicant's analysis. Our consultant's report is included in Appendix M of this report. We agree with our consultant that the analysis is acceptable.

The results of the analysis are summarized in Section 3 of the applicant's February 24, 1984 submittal. Of the 48 plant fire areas containing unprotected steel, three areas will be provided with insulation and eight areas will be provided with automatic sprinkler systems. We have reviewed the affected areas and conclude that the automatic sprinkler systems will provide adequate protection of the steel by limiting any potential fire exposures and corresponding room temperature increases. There are 37 areas where the steel is unprotected.

The applicant will provide penetration seals for all penetrations of fire-rated walls of floor/ceiling assemblies. The penetration seals have been subjected to qualification tests using the time-temperature curve specified by ASTM E-119, "Fire Test of Building Construction and Materials." By FPER Amendment 4, the applicant committed to utilize the acceptance criteria specified in our guidelines, which specify that the maximum temperature on the unexposed side of the penetration seal should not exceed 325°F during the qualification test period.

By Amendment 6, the applicant informed us that the penetrations involving annular pipe anchors did not meet the 325°F acceptance criteria. Annular pipe anchors are used in the type of penetration involving a single pipe routed through a steel penetration sleeve that is embedded in a concrete wall. The pipe anchor consists of a steel plate spanning the annular space between the pipe and the penetration sleeve, and which is welded to both the pipe and the penetration sleeve over its entire circumference. Fire resistance for this type of penetration assembly is provided by installing mineral wool in the annular space to a minimum depth of 12 inches. This configuration has been tested for a 3-hour fire rating at the National Gypsum Company Research Center in cooperation with Factory Mutual Research. The assembly withstood the fire test and hose stream test with a maximum temperature of 425°F on the unexposed side of the annular anchor, measured at a location 1 inch from the surface of the pipe. This temperature is attributable to heat conduction through the steel pipe.

Although the pipe anchors do not meet the specific ASTM E-119 temperature rise limitations, the test results showed that the fire would not spread to the unexposed side of a protected fire barrier during a 3-hour test period. We, therefore, have reasonable assurance that the integrity and temperature transmission through the penetration assembly will not affect the capability to achieve and maintain safe shutdown considering the effects of a fire involving fixed and potential transient combustibles in the plant. This is in conformance with our guidelines in Section C.5.a of BTP CMEB 9.5-1, and is, therefore, acceptable.

The applicant is providing 2-hour-rated fire barriers for enclosed stairwells. By FPER Amendment 4, the applicant stated that the stairwell enclosures would consist of 8-inch thick masonry walls with self-closing 1-1/2-hour rated fire doors. This provides a level of safety consistent with our guidelines and, therefore, we find this acceptable.

In Amendment 6, the applicant stated that except for steamtight, watertight, missile resisting and oversize doors, the door openings in fire-rated barriers are provided with Underwriters Laboratory (UL)-labeled fire door assemblies that have ratings commensurate with the fire ratings of the walls in which they are installed. By FPER Amendment 4, the applicant stated (1) that the steamtight doors are similar to labeled fire doors in construction, (2) that adequate gaps are provided between the doors and frames to allow for expansion and distortion during a fire, and (3) that in no case does the fire load on either side of the doors exceed an equivalent fire severity of 30 minutes.

We find that although the steamtight doors are not 3-hour rated doors, due to the low fuel loading they provide an equivalent level of protection for the areas where they are installed.

In regard to the watertight, missile resisting, and oversize doors, each individual area was evaluated with respect to its fuel load, fire suppression and detection systems, and proximity to safe shutdown equipment to determine if fire-rated assemblies provided are adequate for the areas affected and meet the guidelines in Section C.5.a of BTP CMEB 9.5-1. Based on this evaluation, we found the fire barriers for these areas acceptable.

During our site audit, we noted that throughout the plant many of the fire doors' self-closing mechanisms are held in the open position by fusible links. Although we deem this practice acceptable during construction, the fusible links should be removed, and the doors should be properly closed prior to startup.

By letter dated August 22, 1984, the applicant committed to remove the fusible links prior to startup. We find this acceptable. Based on our review, we conclude that with the acceptable deviations, the fire doors provided meet our guidelines in Section C.5.a of BTP CMEB 9.5-1 and are, therefore, acceptable.

Ventilation ducts that penetrate fire barriers are provided with fire dampers. The fire dampers will be UL labeled and installed according to the manufacturer's directions. Three-hour-fire dampers will be provided in all 3-hour-fire-rated barriers. We conclude that the fire dampers will be provided in accordance with the guidelines of BTP CMEB 9.5-1, Section C.5.a and are, therefore, acceptable.

The thermal insulating materials are non-combustible or have flame-spread and smoke-developed ratings of 25 to 50, respectively, as tested by UL. Interior walls and structural components, radiation shielding materials, and soundproofing and interior finishes are non-combustible or listed by a nationally recognized testing laboratory, such as Factory Mutual (FM) or UL, for flame spread, smoke, and fuel contribution of 25 or less. We find that this is in accordance with the guidelines of BTP CMEB 9.5-1, Section 9.5-1, Section C.5.a, and is, therefore, acceptable.

By FPER Amendment 4, the applicant committed to provide metal roof deck construction that meets the criteria for Class 1 roof deck systems in the FM system approval guide, in accordance with our guidelines. Based on our review, we conclude that metal roof deck construction meets the guidelines of Section C.5.a.10 of BTP CMEB 9.5-1, and is, therefore, acceptable.

Transformers installed inside buildings are either air cooled, of the dry type, or are insulated and cooled with a non-combustible gas. The main and plant services transformers are located more than 50 feet from any buildings or are separated by 3-hour fire walls. The safeguard and auxiliary transformers are located on the north side of the turbine building, within 14 feet of the building exterior wall. No safety-related equipment is located within the turbine building. The turbine building exterior walls are not rated. The transformers are protected by an automatic water deluge system. We find this an acceptable deviation from the guidelines of BTP CMEB 9.5-1, Section C.5.a, because no safety-related equipment is located in the turbine building. We conclude that the installation of the transformers, with the approved deviation, meets the guidelines of BTP CMEB 9.5-1, Sections C.5.a.12 and 13, and is, therefore, acceptable.

Floor drains are provided for the majority of plant areas. Floor drains are not provided for the 4-kV switchgear compartment, and the static inverter compartments. By FPER Amendment 4, the applicant provided an analysis showing that redundant trains of safety-related equipment in unaffected areas would not be flooded by excess fire fighting water.

Based on our review, we conclude that the location of floor drains will meet the guidelines of Section C.5.a.14 of BTP CMEB 9.5-1, and is, therefore, acceptable.

Based on our evaluation, we conclude that the building design, with the approved deviations, meets our guidelines in Section C.5.a of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.4.2 Safe Shutdown Capability

As part of the FSAR submittal, the applicant provided a report on safe shutdown capability following a fire, in accordance with the requirements of Appendix R (BTP CMEB 9.5-1, Section C.5.b). Further discussion of the safe shutdown capability, including information on cable separation and safe shutdown equipment location, is in FSAR Section 9.5.

The applicant's safe shutdown analysis states that systems needed for hot shutdown and cold shutdown are redundant and that one of the redundant systems needed for safe shutdown would be kept free of fire damage through separation, fire barriers, and/or alternative shutdown capability. To achieve hot shutdown either the reactor core isolation cooling system or the high pressure coolant injection system would be available, in addition to the main steam isolation and safety relief valves, automatic depressurization system valves, the residual heat removal (RHR) system loop A or B, the RHR service water (RHRSW) system loop A or B, and the emergency service water (ESW) system loop A or B. Going to cold shutdown from hot shutdown would require the A loops of the RHR, RHRSW, and the ESW or the B loops of the RHR, RHRSW, and ESW. The safe shutdown review considered components, cabling, and support equipment for systems identified above that are needed to achieve shutdown. The applicant has provided a cable separation review for all rooms of the plant housing safe shutdown equipment to ensure that at least one train of this equipment is available in the event of a fire in any of these rooms. The review identified the safety-related equipment and redundant safe shutdown system cabling and discussed the consequences of a fire in each of these rooms. We have reviewed the applicant's deterministic review of the plant and conclude that it provides an acceptable means of demonstrating that separation exists between redundant safe shutdown trains.

The applicant's review divided the areas by the diesel generator electrical division. Cables and equipment were considered disabled in the area of the fire unless the fire hazards analysis assumed otherwise. No repairs were assumed. The applicant has also identified that alternative shutdown is required for the control room. If fire disables the control room, a remote shutdown panel located in a separate fire protected room in the control structure is provided as an alternative to providing fire protection. The remote shutdown panel is electrically isolated from the control room. (See Section 9.5.1.4.2 below for further discussion on the alternative shutdown capability.)

We reviewed the means of separation proposed to ensure that one train of cables and equipment needed to safely shutdown the plant will be maintained free of fire damage.

We identified twelve areas where this separation was not provided. By Amendment 3, the applicant committed to meet our guidelines for the following areas:

(1) Fire Area 2, 13-kV switchgear area

(2) Fire Area 7, corridor el 239 feet

(3) Fire Area 12, Unit 1, 4-kV switchgear area

(4) Fire Area 20, Unit 1, static inverter compartment

(5) Fire Area 25, auxiliary equipment room

(6) Fire Area 27, control structure fan room

(7) Fire Area 40, corridor el 177 feet

(8) Fire Area 43, safeguard system isolation valve area

By Amendment 5, the applicant revised his commitment for fire area 43. This area will be provided with a separation boundary consisting of 20 feet free of intervening combustibles. We have reviewed the change and concluded that because of the low combustible loading in the area, this is an acceptable deviation to Section C.5.b of BTP CMEB 9.5-1.

The applicant, by Amendment 4, committed to provide a separation boundary between redundant trains, consisting of 20 feet free of intervening combustibles and a water curtain for the following three areas:

(1) Fire Area 44, safeguard system access area

(2) Fire Area 45, CRD hydraulic equipment area and neutron monitoring system area

(3) Fire Area 48, RWCU holding pump compartments, RERS fan area and corridors

Due to the low combustible loading, and configuration of redundant cable in these areas, we find this level of protection acceptable.

In our SER, we incorrectly stated that the applicant had also committed to provide a water curtain for Fire Area 47, RWCU compartments, fuel pool cooling and cleanup (FPCC) compartment, and general equipment area. The components associated with the different shutdown methods are located on opposite sides of the primary containment, such that their horizontal separation is greater than 100 feet, and the only combustible materials in the intervening space are electrical cables in cable trays. A 20-foot-wide zone that is free of combustibles will be maintained between the method A and method B components. No cable trays are located within this combustible-free zone. The combustible-free zone divides the fire area into a western portion and an eastern portion. We have evaluated this area and conclude that because of the low combustible loading, configuration of cables and their location at the ceiling level, an automatic suppression would not greatly enhance the level of fire protection safety. We find this an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1, and is, therefore, acceptable.

We noted that two redundant load centers which are located on the 313' elevation of the reactor building (Fire Area 48) are approximately 35 feet apart. It was our concern that because water curtain is located at the ceiling and is manually operated, a considerable time delay could occur before the heat from a floor-based exposure fire would be dissipated. In this time period, both load centers could be damaged.

By FPER Amendment 6, the applicant committed to provide a radiant energy shield between the load centers because the radiant energy shield will prevent a floor-based exposure fire from damaging the load centers until the sprinklers are activated. We find this an acceptable deviation from Section C.5.b of BTP CMEB 9.5-1, and is, therefore, acceptable.

During our site audit, we noted that a ventilation duct is provided to serve both the remote shutdown panel area, and the adjacent auxiliary equipment room. The remote panel provides alternative shutdown for some of the functions in the auxiliary equipment room. It was our concern that a fire in the auxiliary equipment room could cause smoke and other products of combustion to enter the remote panel area.

By FPER Amendment 6, the applicant committed to modify the HVAC system so that the remote shutdown panel room is maintained at a positive pressure, thereby preventing the infiltration of smoke. We find this acceptable.

Based on our review, we conclude that, with the accepted deviations, the fire protection for safe shutdown meets our guidelines in Section C.5.b of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.4.3 Alternate Shutdown

FSAR Section 7.4.1.4 describes the design and capability of the remote shutdown panel. The present design objective of the remote shutdown panel is to achieve and maintain cold shutdown in the event of an evacuation as a result of a fire that disables the control room. The reactor core isolation cooling (RCIC) system, safety/relief valves (SRVs), and one division of the residual heat removal (RHR) system, RHR service water (RHRSW) system, and the emergency service water (ESW) system can be controlled from the remote shutdown panel to achieve cold shutdown should a fire disable the control room. To ensure the availability of this remote shutdown panel in the event of a control room fire, transfer switches are provided to transfer to the remote shutdown panel enough equipment to provide the capability to go to cold shutdown. These transfer switches provide electrical isolation between the control room and the remote shutdown panel.

The design of the remote shutdown panel complies with the performance goals outlined in the requirements of Section III.L of Appendix R (BTP CMEB 9.5-1, Section C.5.c). 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 SRVs will be used for reactor decay heat removal. Reactor vessel water level, reactor vessel pressure, suppression pool water level and temperature, RCIC pump turbine speed, and RHR system flow are among the 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.

We evaluated the fire protection provided for the remote shutdown panel and conclude that it is not physically separated from the control room in accordance with the guidelines in Section C.5.c of BTP CMEB 9.5-1. The remote shutdown panel is located in the auxiliary equipment room (Fire Area 25), along with power generation control complex (PGCC) cabinets, and, therefore, this area contains systems for both the normal shutdown system and the alternate shutdown capability for both units. By Amendment 4, the applicant committed to enclose the remote shutdown panel in a separate 3-hour-rated enclosure.

We find that, with this commitment, the fire protection provided for the alternate shutdown panel will meet the guidelines of Section C.5.c of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.4.4 Control of Combustibles

Safety-related systems have been isolated or separated from combustible materials as much as possible. The storage of flammable liquids complies with Standard 30 of the National Fire Protection Association (NFPA 30). Compressed gases are stored either outdoors or in nonsafety-related structures whenever possible. However, compressed gas cylinders associated with the primary containment instrument gas system and containment combustible gas monitoring system are located in the reactor enclosure.

By FPER Amendment 4, the applicant stated that the primary containment instrument gas system utilizes cylinders of nitrogen and a nitrogen/hydrogen mixture. The mixture of gases contain 5% hydrogen. If this quantity of hydrogen were inadvertently released, the resultant gas would be diluted to below 4% hydrogen, the lower flammable limit (LFL). Because the quantity of hydrogen will remain below the LFL, during a leak, we find this acceptable.

We find that, the storage of flammable compressed gases will meet the guidelines of Section C.5.d of BTP CMEB 9.5-1 and is, therefore, acceptable.

The hydrogen piping in safety-related areas has been designed to seismic Category I requirements. Based on its evaluation, the NRC staff concludes that the design of hydrogen piping meets the guidelines of Section C.5.d.5 of BTP CMEB 9.5-1 and is, therefore, acceptable.

9.5.1.4.5 Electrical Cable Construction, Cable Trays, and Cable Penetrations

Cable trays are of all metal construction. Electrical cable construction generally passes the IEEE 383-1974 flame test. Only lighting and communications cables do not pass this test. However, because these cables are routed exclusive in conduit and are not routed with cables for safety-related systems we find this acceptable. The cables are designed to allow wetting down with fire suppression water without electrical faulting.

Safety-related cable trays outside the cable spreading room are not provided with continuous line-type heat detectors. Instead, smoke detectors of the ionization or photo-electric type are located in areas through which safety-related cable trays are routed. This method of detection has been selected in lieu of line-type heat detectors because the products of combustion will be detected by the smoke detectors earlier than the heat from a faulted cable would be detected by heat detectors. Because of the increased sensitivity of the ionization detectors, we find this acceptable.

By letter dated November 23, 1983 and February 16, 1984, the applicant identified those areas containing concentrations of cable trays that will be protected by Automatic Suppression Systems.

We have evaluated these areas and agree with the licensee that the configuration of combustibles in these area represent a hazard of sufficient magnitude to warrant the addition of automatic suppression.

Based on our review, we conclude that the protection provided for Electrical Cable Construction, Cable Trays, and Cable Penetration meets our guidelines in Section C.5.e of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.4.6 Ventilation

There are no ventilation systems in the plant designed specifically to exhaust smoke or other products of combustion. Normal plant ventilation systems will be utilized for this purpose. Portable smoke ejectors will be provided to assist in removal of the products of combustion should the normal ventilation systems be unavailable because of damper closures or other failures. Because the normal ventilation system is capable of being realigned to 100% exhaust, we find this acceptable. The power supply and controls for the ventilation systems for the control structure fan rooms are not run outside the fire area served by the system. By FPER Amendment 4, the applicant committed to separate the redundant trains of power supply and control cables by greater than 20 feet. In addition, automatic suppression and detection will be provided. We find this acceptable.

Based on our review, we conclude that the control structure ventilation will meet the guidelines of Section C.5.f of BTP CMEB 9.5-1, and is, therefore, acceptable. Air intake and exhaust ventilation dampers in areas protected by total flooding gas extinguishing systems are provided with mechanisms that will close them upon actuation of the suppression system. Stairwells are designed to minimize smoke infiltration during a fire. Charcoal filters have been provided with water spray systems in accordance with RG 1.52. We find this acceptable.

9.5.1.4.7 Lighting and Communications

The applicant is providing emergency lighting powered from Class IE buses that automatically transfer to the standby diesel generators upon loss of the normal power source. Emergency ac lighting is provided throughout the plant to maintain minimum lighting levels necessary for access to and operation of all safe shutdown equipment for a period longer than 24 hours.

The emergency ac/dc lighting is normally powered from the Class IE buses. In the event of loss of the Class IE ac source, an automatic transfer switch immediately transfers the lighting to the 125-V dc non-Class IE station battery source.

By FPER Amendment 4, the applicant committed to route the cables for the emergency lighting subsystems such that a single fire will not cause the loss of all emergency lighting. In addition, the applicant has committed to install 8-hour self-contained battery-powered lighting units in areas where the existing lighting system does not provide adequate illumination. By Amendment 5, the applicant revised this commitment and will now install 8-hour self-contained battery-powered lights in all areas needed for hot shutdown, and access and egress routes thereto.

Based on our review, we conclude the emergency lighting meets the guidelines of Section C.5.g of BTP CMEB 9.5-1, and is, therefore, acceptable.

The applicant has not provided a fixed communication system independent of the normal plant system. However, a portable radio communications system will be provided for use by the fire brigade and other operations personnel. The system will utilize a distributed antenna network with base station repeaters. The distributed antenna modules will be located throughout the plant. Although the antenna modules are not designed to withstand an exposure fire, the system is designed so that the failure of the one module will not result in failure of the entire antenna system. We find this to be an acceptable deviation.

Based on our review, we find that the communication system with the acceptable deviations meets the guidelines of BTP CMEB 9.5-1, Section C.5.g and is, therefore, acceptable.

9.5.1.5 Fire Detection and Suppression

9.5.1.5.1 Fire Detection

A fire detection system is provided for all areas containing safety-related equipment except for the service water pipe tunnel (Fire Area 75). The components in Area 75 needed for safety shutdown are valves, separated by greater than 200 feet. Due to the low fire hazard in these areas, we find the lack of detection an acceptable deviation from our guidelines.

Fire detectors will also be provided for the diesel-generator access corridors (Fire Areas 124 and 125). We find this acceptable.

By FPER Amendment 4, the applicant identified those areas not provided with detection that are adjacent to safety-related areas. In all cases, the adjacent areas are separated by 3-hour rated barriers, and do not contain significant amounts of combustibles. Because of the low potential for a fire in any of those areas to breach the 3-hour barrier and threaten safety-related equipment in adjacent areas, we find this acceptable.

The fire and smoke detection system is in compliance with NFPA 72A. The system does not comply with the requirements of NFPA 72D in the following areas:

(1) No device is provided for permanently recording incoming signals with the date and time of receipt.

(2) Operation and supervision of the system is not the primary function of the operators.

(3) In lieu of complete reliance on NFPA 72E, smoke and fire detector locations are established by a qualified fire protection engineer.

By FPER Amendment 4, the applicant stated that plant operating procedures will require the control room operators to record all alarms of the detection system in the plant log book. We find this equivalent to a mechanical recorder.

By FPER Amendment 4, the applicant also stated that the location and placement of detectors was in accordance with the guidelines of NFPA Std. 72E, except where special conditions did not permit. In such cases, a registered fire protection engineer located the detectors based on engineering judgment as permitted by NFPA Std. 72E. We find this acceptable.

Power for the early warning fire and smoke detection system is provided from a Class 1E ac motor control center. In the event of the loss of offsite power, the motor center is powered from the standby diesel generators.

We find that primary and secondary power supplies for the fire detection system satisfy the provisions of Section 2220 of NFPA 72D and are, therefore, acceptable.

The detection and actuation systems for the Halon system, the total flooding carbon dioxide system, and the deluge and preaction sprinkler system are connected to a non-Class 1E dc power supply. The charger associated with the non-Class 1E batteries is powered from a Class 1E ac motor control center that is powered from the standby diesel generators in the event of loss of offsite power.

We find this arrangement satisfies the provisions of Section 2220 of NFPA 72D, and is, therefore, acceptable.

Based on our review, we conclude that, with the accepted deviations, the fire detection system meets our guidelines in Section C.6.a of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.5.2 Fire Protection Water Supply System

The water supply system consists of two fire pumps; one pump is electrically driven and the other is diesel-engine driven. Each fire pump is separately connected to a buried 12-inch water main loop around the plant. Each fire pump has a rated capacity of 2500 gpm at 125 psig. The fire pumps and controllers are UL listed. The fire pump installation has been designed and installed and will be tested in accordance with NFPA 20.

The fire pumps are located in the circulating water pump house. The fire pumps are separated by 3-hour-fire-rated barriers. When the fire pumps are not operating the fire protection water system is pressurized by a 2-inch connection to the service water system.

By FPER Amendment 4, the applicant stated that maximum pressure developed by the service water system is substantially less than the fire water piping's design pressure. Therefore, overpressure damage will not occur. Check valves are provided in the 2-inch line, however, if the check valves were to stick open, the fire pumps have sufficient capacity to compensate for the amount of water discharged to the service water system. Because of these design features, the service water system connection will not adversely affect the performance of the fire protection water system. We find this acceptable.

Based on our review, we conclude the fire pumps will meet the guidelines of Section C.6.b.4 of BTP CMEB 9.5-1, and are, therefore, acceptable.

The source of water for the fire protection system is two cooling tower basins each of which will contain over 3,000,000 gallons. For a system pumping capacity of 5000 gpm, this allows continuous operation of both fire pumps for 20 hours which is well in excess of the 2-hour criterion in the staff's fire protection guidelines. If one cooling tower basin or supply line is not available, the remaining water source provides both fire pumps with a 10-hour supply of water. Water for the fire pumps is taken from either Unit 1 or Unit 2 cooling tower water basins through connections to the circulating water lines.

The greatest water demand for the fixed fire suppression system is 2090 gpm. Coupled with 500 gpm for hose streams, this creates a total water demand of 2590 gpm. NFPA 20, which is referenced in the guidelines, recommends that fire pumps be selected for operation in the range of 90 to 150% of its rated capacity. Because 2590 gpm falls within this range for a 2500-gpm rated capacity pump, we find find that the water supply system can deliver the required water demand with one pump out of service.

Yard hydrants are provided at intervals of 250 to 300 feet along the fire protection water supply loop. The lateral to each yard hydrant is provided with a key-operated isolation valve to facilitate hydrant maintenance and repairs without shutting down any part of the fire water supply system. Standard hose houses are provided at intervals of 650 feet, in accordance with NFPA 24.

Approved post-indicator sectional control valves are provided to isolate portions of the underground main for maintenance or repair without shutting off the supply to primary and backup fire suppression systems that serve areas containing or exposing safety-related systems.

By FPER Amendment 4, the applicant committed to either electrically supervise the valves or lock them in the correct position with administrative controls to inspect the valve positions in accordance with the plant Technical Specifications. We find this acceptable.

Based on our review, we conclude the fire protection water supply system will meet the guidelines of Section C.6.c of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.5.3 Sprinkler and Standpipe Systems

The wet pipe sprinkler systems, deluge systems, and pre-action systems meet the provisions of NFPA 13 and NFPA 15. The areas equipped with water suppression systems are listed in Section 2.2-2.5 of the applicant's fire protection evaluation report.

During our site audit, we noted that the sprinkler system in Fire Area 27 (Fan Room) did not provide coverage for the entire area as recommended by NFPA 13.

By FPER Amendment 6, the applicant revised the description of the sprinkler system coverage in this area to show that only partial suppression has been provided. We have reviewed the protection provided and based on the configuration and because of the low fuel load in the area, we find partial sprinkler coverage for this area acceptable.

The sprinkler systems and manual hose station standpipe connections to the looped interior fire protection headers are arranged and valved so that in many cases a single break could disable both the primary and secondary means of fire suppression in one area. By FPER Amendment 4, the applicant committed to provide a standpipe system such that in the event a standpipe were to break and cause a loss of sprinkler systems and their associated backup hose stations, all sprinkled areas could be provided with an effective hose stream from a hose station attached to the closest standpipe adjacent to the affected area. We find this acceptable.

Manual hose stations are not located throughout the plant in accordance with NFPA 14. By FPER Amendment 4, the applicant committed to provide hose coverage to all areas that present a fire exposure hazard to safety-related equipment, either by installing additional hose stations or by providing additional lengths of hose at existing stations. We find this acceptable.

Three-inch-diameter piping is used to serve up to two hose stations in some areas. This does not meet the guidelines of Section C.6.c(4) of BTP CMEB 9.5-1. By FPER Amendment 4, the applicant verified by calculation that the fire protection system can provide the flow and pressures required in NFPA 14 for these standpipe locations, considering the operation of two hose stations simultaneously with the largest water demand flowing from any automatic suppression system in the vicinity of the hose stations. We find this acceptable.

Standpipe system piping supply hose stations protecting safe shutdown equipment are not seismically supported or designed. By FPER Amendment 4, the applicant provided the results of an analysis which demonstrates acceptable piping integrity under seismic conditions for standpipe in areas containing safe shutdown equipment. We find this acceptable.

By letters dated June 21 and August 8, 1984, the applicant requested schedular deviations for completion by 5% power of: (1) sprinkler systems in fire areas 41 (RCCW Equipment Area), and 42 (Safeguard System Access Area) and 47A (General Equipment Areas, Reactor Building Elev. 283').

For the items to be completed prior to exceeded 5% power, the applicant committed to implement the applicable Plant Technical Specifications action statements. Because the fission product inventory in the core is not appreciable and therefore the health and safety of the public is not affected, and based on the applicant's commitment to implement the Plant Technical Specifications action statements, we find that adequate fire protection measures have been provided. Therefore, the applicant's request for deferral of the items to be completed prior to exceeding 5% power has been granted.

By letter dated June 21, 1984, the applicant also requested a schedular deviation for completing by the startup after the first refueling outage, modifications to the standpipe system in the control structure at ele. 332' and 350' as necessary to provide at least 100 gpm flow at 65 psig at all hose stations. The applicant subsequently indicated that this item would be completed prior to exceeding 5% power.

For this item, the modifications are designed to enhance the existing standpipe system. We have evaluated the existing system and find that temporary hoses can be supplied from adjacent areas until the modifications are completed. Therefore, the applicant's plans for this item to be completed prior to 5% power is acceptable.

Based on our review, we conclude that the sprinkler and standpipe systems meet our guidelines in Section C.6.c of BTP CMEB 9.5-1, and are, therefore, acceptable.

9.5.1.5.5 Halon Suppression Systems

Two separate Halon extinguishing systems are provided for the protection of the power generation control complex (PGCC) in the auxiliary equipment room. One system serves the Unit 1 side of the room, and the second system serves the Unit 2 side of the room. Each system discharges simultaneously into all floor sections in its respective half of the room.

The Halon extinguishing systems are designed in accordance with NFPA 12A. Each Halon system is designed to achieve a concentration of 20% by volume within the raised flooring that it serves, with a concentration of 6% by volume being reached within 10 seconds after discharge begins. The first Halon cylinder is discharged automatically and has sufficient capacity to maintain the 20% concentration for 20 minutes. The remaining Halon cylinder, which is manually discharged, provides a 100% reserve capacity.

By FPER Amendment 4, the applicant provided the results of a comparison of the Halon 1301 Systems to the GE Topical Report NEDO-10466, Revision 2, dated March 1978, which was previously approved and is the basis for our acceptance of the PGCC system.

The systems are identical, with one deviation from the specifications of NEDO-10466, to the extent that it stipulates the use of steel and aluminum in the floor plates in the PGCC design. Approximately 4% of the floor plates in the plant are of a nonmetallic, composite material. This substitute material is used in lieu of the standard floor plates to accommodate irregular shapes and close tolerance fittings.

We had two concerns with its use. The first is that the material would represent a significant hazard, based on its flammability. The second concern is that the plates would not remain in place upon discharge of the Halon fire suppression system. The composite material was tested in accordance with the method of ASTM E-84. The flame-spread rating as determined by this test was less than 50, and the smoke-developed rating was less than 10. This conforms with Section B.4 of BTP CMEB 9.5-1, and is, therefore, acceptable.

The applicant has verified that during discharge tests of the Halon fire extinguishing system, the substitute floor plates remained in place. On the basis of our evaluation, we, therefore, conclude that the limited use of the substitute floor plates in the PGCC system represents an acceptable deviation from NEDO-10466.

Based on our review, we conclude that the Halon 1301 systems meet our guidelines in Section C.6.d of BTP CMEB 9.5-1, and are, therefore, acceptable.

9.5.1.6.1 Primary and Secondary Containment

Manual hose stations are provided at the entrances to the drywell with sufficient length of hose to reach any location within the drywell.

During normal operation, the primary containment is inerted. The protection of redundant cables is in accordance with our guidelines as discussed in Section 9.5.1.4.5 of this report.

Based on our review, we conclude that primary and secondary containments are in accordance with our guidelines in Section C.7.a of BTP CMEB 9.5-1, and are, therefore, acceptable.

9.5.1.6.2 Control Room

The applicant states the control room complex is separated from all other areas of the plant by 3-hour-fire-rated assemblies. Peripheral rooms in the control room complex consist of offices. Each room is separated from the control room by 1-hour-fire-rated barriers. Smoke detectors that alarm and annunciate in the control room panel are provided in each room.

By FPER Amendment 4, the applicant provided details concerning the design and protection of the control room peripheral rooms. Based on our review, we conclude that the control room peripheral rooms will meet the guidelines of Section C.7.b of BTP CMEB 9.5-1, and are, therefore, acceptable.

During our site audit we could not verify that the peripheral room ceilings were qualified as fire barriers. By FPER Amendment 6, the applicant provided additional information to verify that a 1-hour rated barrier is provided in accordance with Section C.7.b of our guidelines.

By FPER Amendment 4, the applicant provided the results of tests which showed that, with the existing separation of components in the control room cabinets, smoke will be detected by the control room operators or ceiling mounted detector prior to the loss of redundant equipment. The applicant has also committed to install smoke detectors in the PGCC termination cabinets.

Based on our review, we conclude that the control room detection system meets the guidelines of Section C.7.b of BTP CMEB 9.5-1, and is, therefore, acceptable.

The applicant has provided an alternate shutdown system for the control room. The alternate shutdown system is reviewed in Section 9.5.1.3 of this report.

The outside air intakes for the control room ventilation systems are equipped with ionization smoke detectors that alarm in the control room. In the event of a fire, a smoke venting system can be manually initiated to purge smoke from the control room.

Automatic suppression systems are not provided for the electrical cabling routed through the space above the suspended ceiling in the control room. By FPER Amendment 4, the applicant committed to enclose all cables in steel cable trays, and to wrap all exposed cables with a flame-retardant material. The flame-retardant material will prevent the rapid spread of flames through the area. With the installed detection system, prompt notification of fire conditions will be received. Because the cables will be in covered metal trays, manual fire extinguishing action will be adequate to contain the fire.

Based on our review, we conclude the protection provided for the control room complex will meet the guidelines of Section C.7.b of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.6.3 Cable Spreading Room

By FPER Amendment 4, the applicant provided a description of the protection provided for the cable spreading room. The cable spreading room is separated from the balance of the plant by 3-hour-fire-rated walls and floor/ceiling assemblies. All penetrations through fire-rated barriers are fitted with 3-hour-fire-rated dampers and/or 3-hour-fire-rated penetration seals.

Separate cable spreading rooms have not been provided for each division of redundant safe shutdown system circuits. However, an alternate shutdown system has been provided for the cable spreading room. The alternate shutdown system is reviewed in Section 9.5.1.4.3 above.

The primary fire suppression system in the cable spreading room is a total flooding carbon dioxide system. Backup suppression capability for the cable spreading room is provided by a wet pipe sprinkler system with fusible-type sprinkler heads. Electrical cabling is designed to allow wetting down without electrical faulting.

By letter dated June 21, 1984, the applicant requested a schedular deviation to defer the installation of an access stairway to serve as a second means of fire brigade access to the Unit 2 cable spreading room until the first refueling outage. Because the Unit 2 cable spreading room has not yet been completed and does not affect the safety of Unit 1, we find this acceptable.

Based on our review, we conclude that the protection provided for the cable spreading room meets the guidelines in BTP CMEB 9.5-1, Section C.7.c, and is, therefore, acceptable.

9.5.1.6.4 <u>Switchgear Rooms</u>

The Division I and Division II switchgear rooms are separated from each other and from other plant areas by 3-hour fire rated walls. The floor supporting the switchgear rooms is protected as described in Section 9.5.1.4.1 of this report.

Automatic fire detection is provided by ionization smoke detectors. Manual protection is provided by standpipe hose stations and portable extinguishers.

During our site audit, we noted that a common bus-duct interconnects all trains of 4160 volt switchgear. We could not verify that fire stops were installed inside the bus-duct where it penetrates the 3-hour walls. It was our concern that this could cause a common mode failure of both redundant trains.

By letter dated August 8, 1984, the applicant stated that all redundant trains are not interconnected. For a fire in any of the switchgear rooms, one redundant train of switchgear will be available in a separate fire area. This meets Section C.5.b of our guidelines, and is therefore, acceptable.

Based on our review, we conclude that the switchgear rooms meet our guidelines in Section C.7.c of BTP CMEB 9.5-1, and are, therefore, acceptable.

9.5.1.6.5 <u>Safety-Related Battery Rooms</u>

The battery rooms are separated from each other and from the balance of the plant by 3-hour rated walls. The floor that supports the battery rooms is protected as described in Section 9.5.1.4.1 of this report.

Ionization smoke detection systems are provided in each battery room. Hose stations and portable fire extinguishers are available in the areas for manual fire suppression. The ventilation system is designed to maintain the hydrogen levels below 2%. Loss of ventilation alarms have been provided for each battery room.

Based on our review, we conclude that the battery rooms meet our guidelines in Section C.7.j of BTP CMEB 9.5-1, and are, therefore, acceptable.

9.5.1.6.6 Emergency Diesel Generator Rooms

By FPER Amendment 4, the applicant committed to enclose each diesel generator and its day tank in 3-hour rated fire barriers consisting of reinforced concrete walls and 3-hour rated, Class A fire doors.

Each 800-gallon diesel fuel oil day tank is located in a separate enclosure designed with walls, floor, and ceiling that have a 3-hour-fire-resistive rating and are sized to contain the total contents of the tank.

Each diesel fuel oil day tank room is protected by an automatic preaction sprinkler system. The system is activated by heat detectors. Additional early warning detection is provided by ionization smoke detectors and flame detectors.

Based on our review, we conclude the protection provided for the diesel generators will meet the guidelines of Section C.7.i of BTP CMEB 9.5-1, and is, therefore, acceptable.

9.5.1.6.7 Cooling Towers

The cooling towers' construction includes combustible polyvinyl chloride material. This does not meet the guidelines of BTP CMEB 9.5-1, Section C.7. The sole source of fire suppression water is provided from the cooling tower basins.

By FPER Amendment 4, the applicant verified that the suction lines to the fire pumps are arranged so that if one of the cooling towers becomes unavailable, the suction line can be switched to the functional tower. Because of this dual-suction capability, we find this acceptable.

Based on our review, we conclude the cooling towers will meet the guidelines of Section C.7 of BTP CMEB 9.5-1, and are, therefore, acceptable.

9.5.1.7 Summary of Deviations and Conclusions

<u>Summary of Accepted Deviations from CMEB 9.5-1</u>

1. Criteria for Protection of Structural Steel (Section 9.5.1.4.1)
2. Unrated, Steamtight/Watertight/Missile Resisting/Oversize doors (Section 9.5.1.4.1)
3. Transformer Separation (Section 9.5.1.4.1)
4. Unrated, Fire Area Boundaries (Section 9.5.1.4.2)
5. Implementation of Some Features After Licensing (Section 9.5.1.5.3)
6. Unprotected Antenna Modules (Section 9.5.1.4.7)
7. Safety Related Areas Without Fire Detection (Section 9.5.1.5)

<u>Conclusion</u>

Based on our evaluation, we conclude that the fire protection program with the accepted deviations meets the guidelines of BTP CMEB 9.5-1 and GDC-3 and is, therefore, acceptable.

13 CONDUCT OF OPERATIONS

13.5 Station Procedures

13.5.2 Operating and Maintenance Procedures

13.5.2.2 Operating and Maintenance Procedure Program

In a letter from E. J. Bradley to A. Schwencer, dated May 18, 1983, the applicant submitted draft changes to this section of the FSAR. These changes include the replacement of emergency procedures with transient response implementation plan (TRIP) procedures and the addition of two new categories of procedures entitled (1) "Events and Special Events Procedures," for actions following an operator observation of an event of emergency or unusual nature, and (2) "Off-Normal Procedures," for actions following operator observation of an offnormal (nontransient) condition.

As a result of its review of this information, the NRC staff concluded that the development of these event procedures appeared to be in conflict with the function approach to emergency conditions of the NRC staff approved BWROG EPGs the applicant has committed to implement. However, the applicant has further stated that these procedures are intended to address events and conditions such as flooding, earthquakes, and toxic gas in the control room, which may lead to use of the TRIP procedures. The applicant committed to further revise the FSAR to describe how the event procedures lead to the TRIP procedures when the plant symptoms warrant it. Revision 23 to the FSAR dated August 31, 1983, addressed this concern. Based on the review of this revision, review of Administrative Procedure A-94, "Procedure for Preparation and Control of Transient Response Implementation Plan (TRIP) Procedures," and presentations made during the in-progress audit of the Detailed Control Room Design Review conducted during the week of December 6, 1983, the staff determined that there is no conflict between the two groups of procedures. The TRIP procedures are to be used when event procedures are unsuccessful in resolving a plant condition and the entry conditions of a TRIP procedure are reached. When this occurs, the function-oriented TRIP procedures will take precedence over the event procedures. Because there is no conflict, the NRC staff concludes that the applicant's program for use of operating and maintenance procedures meets the guidelines in SRP 13.5.2 and is, therefore, acceptable.

13.5.2.3 Reanalysis of Transients and Accidents; Development of Emergency Operating Procedures, Action Item I.C.1

In the SER the staff reported that the schedule and review requirements for TMI Task Action Plan (TAP) Item I.C.1 have been modified by Supplement 1 to NUREG-0737, "Requirements for Emergency Response Capability" (Generic Letter No. 82-33), dated December 17, 1982. The staff also reported that the applicant would implement a program of emergency operating procedures (EOPs) based on the Boiling Water Reactors Owners' Group (BWROG) Emergency Procedure Guidelines (EPGs) Revision 2. Supplement 1 to NUREG-0737 requires that each applicant and licensee submit a Procedures Generation Package (PGP) at least 3 months prior to the date it plans to begin formal operator training on the upgraded procedures. Staff guidance for PGPs was provided in NUREG-0899, "Guidelines for the Preparation of Emergency Operating Procedures." In accordance with the Generic Letter, the PGP must include:

1. Plant-Specific Technical Guidelines
2. A Writer's Guide
3. A Description of the Program for Validation/Verification of EOPs
4. A Description of the Program for Training on the Upgraded EOPs

The applicant submitted the Limerick PGP for staff review in a letter from Mr. S. L. Daltroff to Mr. A. Schwencer dated January 19, 1984. The PGP included the following items:

1. Administrative Procedure A-94, "Procedure for the Preparation and Control of Transient Response Implementation Plan (TRIP) Procedures." This addresses both the writer's guide and the verification and validation program requirements.

2. The Limerick-specific TRIP procedure bases prepared to support the procedures, and descriptions of calculations of three set points for operator action which are adapted from the generic EPGs to the Limerick design. This material was submitted as the plant's specific technical guidelines and deviations from the generic guidelines.

3. A description of the training program on the TRIP procedures.

The staff's review was conducted to determine the adequacy of the applicant's program for preparing and implementing EOPs. The objectives of NUREG-0899 and the requirements of Supplement 1 to NUREG-0737 were used as the basis for the review.

Plant-Specific Technical Guidelines

The review of the Limerick-specific technical guidelines evaluated the description of the process for preparing the EOPs from the generic guidelines, audited sample procedure step bases, and evaluated the description of deviations from the generic guidelines. From the FSAR commitments, TRIP procedure bases, and discussions during the in-progress audit of the Detailed Control Room Design Review (DCRDR), the EOPs appear to be directly based on the approved generic guidelines with the exception of the applicant-identified calculational differences as discussed below.

A. Introduction

The Limerick Emergency Operating Procedures (EOPs) are directly based on the BWR Owners Group Emergency Procedure Guidelines (EPGs) with the exception of three plant-unique calculational differences. The EPGs are contained in NEDO-24934, Revision 2, June 1982. The deviations from the generic calculational methods are:

(1) the primary containment pressure limit,
(2) the drywell spray flow rate limit, and
(3) the drywell spray initiation pressure limit.

The staff safety evaluation of revisions of NEDO-24984, dated February 4, 1983 (Generic Letter 83-05), identified these areas as requiring more work. Specifically, the criterion for defining venting pressure needed to be determined and the overly conservative limits in the determination of drywell spray flow rate needed to be reduced. The applicant's calculational methods, as presented in a letter dated January 25, 1984 for the deviations as applied to the Procedures Generation Package (PGP) address these concerns. The staff SER on BWR EPGs recognized that it is not appropriate to determine the primary containment pressure limit generically. Since this limit was to be used in the EOPs as an indicator for containment venting, the staff established an interim limit of twice the design pressure for venting, subject to a plant-unique analysis to demonstrate containment integrity. The applicant has provided an analysis specific to Limerick which defines an appropriate venting pressure. Our evaluation of this analysis is provided in Section B.

The drywell spray flow rate limit and drywell spray initiation pressure limit are related in that spray-cooling is used to avoid containment damage. The staff SER on BWR EPGs noted that that drywell spray flow rate limit (approximately 10% of flow capability) is very conservative (low). A more realistic (higher) spray flow limit may be determined on a plant-specific basis. The spray initiation pressure limit is determined based on the resultant acceptable flow rate. Our evaluation of these items is also summarized in Section B.

B. Evaluation

Primary Containment Pressure Limit

The Limerick primary containment is a steel-lined, reinforced concrete structure consisting of a truncated cone topped by a steel head and connected to a cylinder supported on a foundation mat, and a diaphragm slab dividing the cone and the cylinder into a drywell and a suppression pool. The Limerick containment is designed for a pressure of 55 psig.

The BWR Owners Group EPGs call for containment venting as the last step in a sequence of procedural steps involving operator actions designed to reduce containment pressure. The staff SER on the BWR EPGs established an interim limit of twice the design pressure for venting with the understanding that more precise analyses may be used to establish a venting pressure limit. These analyses, in general, could consider containment integrity structural tests, purge valve operability and leaktightness of gaskets and seals. The applicant established that the venting pressure is limited by purge valve operability and system requirements for safety relief valve (SRV) actuation. Additional information was provided by the applicant in letters dated June 15 and August 2, 1984. This information established a basis for the selection of 70 psig as the containment pressure limit for venting of the Limerick containment. The results of the analysis were also used to establish a sequential use of preferred vent paths, generally from small (2-inch I.D.) to large (24 inch I.D.). The applicant has stated that the purge valves in the identified vent paths have been determined by analyses of performance characteristics to be operable for differential pressures from 76 psid to over 150 psid. The selection of 70 psi venting pressure ensures that venting will be initiated before vent valve operability is challenged.

The venting sequence to be specified in the procedural step was determined based on consideration of fission product retention, and the potential for causing adverse secondary containment environmental effects, including the potential for equipment damage. The use of the smaller (2 inch) lines allows filtration of the containment atmosphere through the Standby Gas Treatment System (SGTS). Purging from the suppression pool generally takes precedence over purging from the drywell. This action takes advantage of suppression pool scrubbing to reduce offsite radiation doses. The prescribed sequencing of valves will permit a controlled venting to limit the rate of release in order to stabilize containment pressure near the venting pressure. These considerations are consistent with the staff SER on the generic EPGs which concluded that a controlled release from venting would be preferred over the loss of suppression pool water and an uncontrolled release of fission product activity due to containment rupture.

The applicant has also considered essential system operability in the selection of the venting pressure, specifically the pneumatic supply-pressure requirements for the Automatic Depressurization System (ADS) Safety Relief valves. The Limerick design presently has a gas supply pressure for the Primary Containment Instrument Gas System in the range of 95-110 psig as stated in the June 15, 1984 letter. Since the SRVs have a required pneumatic system differential pressure (above containment pressure) of 25 psid, as stated in the June 15 and August 2, 1984 letters, the defined venting pressure of 70 psi will ensure that the SRVs will be operable if called upon.

The staff has reviewed the material provided by the applicant as justification for the selection of 70 psi as the Containment Pressure Limit for venting of the Limerick primary containment. We agree that the approach taken by the applicant satisfies the requirement established in the SER for the BWR EPGs for more precise criteria for defining venting pressure and that the information provided is an adequate basis for the selection of 70 psig.

The ultimate structural capability was determined by the applicant to be about 140 psi based on a study performed by the Bechtel Power Corporation for the LGS dated February 10, 1981. Since the Limerick containment is planned to be vented at a much lower pressure, the proposed venting criterion of 70 psig is acceptable for structural considerations. In addition, the applicant has stated that structural deformations are not expected to be substantially different than those observed during the Structural Integrity Test (1.15 times design).

The staff is expecting a proposed revision to the generic EPGs in the future which will include specific discussion of these considerations. Any long-term followup will be pursued generically in connection with the BWR Owners Group EPGs.

Drywell Spray Initiation Pressure Limit

A summary of the applicant's calculational methods for this deviation are supplied in their letters dated January 25 and April 27, 1984. The EOPs for

Limerick include a curve (designated as Curve SP/L-4) which combines the parameters Suppression Pool Air Temperature and Drywell Pressure. This curve identifies a safe area for the operator to initiate the drywell sprays. The safe area is that for which actuation of the drywell sprays will not result in a primary containment negative pressure exceeding the design pressure of -5 psig. This was previously considered as a design basis event analysis in the Limerick Final Safety Analysis Report as an inadvertent drywell spray actuation which resulted in a maximum negative drywell pressure of -4.3 psig. The analysis assumed initial conditions of maximum single train drywell spray flow at 50°F, and operation of only three of the four wetwell-to-drywell vacuum breakers. This calculation and the associated analytical methodology were found acceptable by the staff during the review of the Limerick Generating Station FSAR. In the staff's SER for Limerick, the staff concluded that the ability of the primary containment was adequate to accommodate, with sufficient margin, the external pressure from the worst postulated accident.

For purposes of the PGP, the subject calculation was refined to determine the least amount of non-condensibles calculated to remain inside the primary containment following isolation of the drywell purge valves, and to incorporate experimentally determined wetwell-to-drywell vacuum breaker flow coefficients. The remaining methodology was the same as the design basis case. For these conditions, it was determined that a maximum drywell negative pressure of -4.686 psig would be achieved. This pressure is less than the pressure for the design basis case because of the assumption that a small break LOCA occurs during drywell purging. This results in less non-condensibles driven into the wetwell through the downcomers during pressurization of the drywell. This minimum amount of non-condensibles will be returned to the drywell during depressurization from drywell spray initiation and will result in a greater pressure differential. This pressure is still within the design limit of the Limerick containment. This calculation indicates that the use of 9500 gpm as the Drywell Spray Flow Rate Limit is appropriate. On this basis, the Drywell Spray Initiation Pressure Limit Curve was established by the applicant for the EOPs.

This calculation was also performed to provide a basis more representative of the Limerick design. The generic calculation would normally account for makeup flow of non-condensibles entering through secondary containment to primary containment vacuum breakers. Since these vacuum breakers are not part of the Limerick design, the revised calculation is more appropriate. This deviation from the generic study is therefore acceptable to the staff.

It is also noted that the presently-acceptable EPGs contain a restriction on drywell spray flow rate of approximately 10% of flow capability. The staff SER on the EPGs stated that the present limit is very conservative and that a more realistic flow rate should be determined. The Limerick plant-unique calculation satisfies this staff requirement and is acceptable.

The use of a single drywell spray flow train is necessary since actuation of both trains concurrently would result in a pressure below the design basis -5 psig. Actuation of both trains has been prohibited by Limerick administrative controls (keylock switches). Limiting the flow rate to values less than full flow from one train is not necessary since the transient negative pressure for one train was never worse than the design negative pressure.

C. Conclusions

The staff has reviewed the Limerick-unique EPG analyses and calculations related to the development of the Limerick EOPs. Based on our review, the staff concludes that the calculations were performed with acceptable analytical methods and identification of the deviations is responsive to the open items in the staff safety evaluation on the BWR EPGs issued February 4, 1983. Specifically, the use of 70 psig as an interim venting criterion in the emergency procedures is acceptable. Also, the use of full drywell spray flow from one train (9500 gpm) is acceptable. With regard to venting at 70 psig, the staff recognizes that a proposed revision of the generic guidelines will include redefinition of the venting criteria. Any long-term followup will be pursued generically in connection with the BWR Owners Group EPGs.

Writers Guide

The staff reviewed the Limerick writer's guide to determine if it provided acceptable methods to meet the objectives of NUREG-0899. Although the Limerick EOPs are being implemented in flow chart form, the objectives of NUREG-0899 still apply. The review revealed that the objectives of NUREG-0899 had been carefully addressed. The staff concluded that following the Limerick's writer's guide should result in flow chart procedures that are adequately useable, accurate, complete, readable, convenient to use, and acceptable to the control room operators. Because the writer's guide provides acceptable methods to meet the objectives of NUREG-0899, the staff concludes that the writer's guide is acceptable.

Program for Validation/Verification of EOPs

The Limerick validation and verification program was reviewed using the objectives of NUREG-0899. The program consists of separate checks using desk reviews, plant-reference simulator exercises, and control room walkthroughs to ensure the EOPs conform to the generic guidelines and trained operators can use the EOPs to manage an emergency condition. Based on the review of the program description, it appears that the applicant's program will adequately meet the applicable objectives of NUREG-0899 and will ensure that the EOPs meet the objectives of the writer's guide. Therefore the staff found the program acceptable.

Program for Training

The applicant's description of the EOP training program was also reviewed using the objectives in NUREG-0899. The training consists of classroom instruction and simulator exercises of the EOPs. It was determined that the training plan should provide operators an understanding of the EOPs, their bases, and their use. The training plan was found acceptable.

Summary

The staff concludes (1) that the applicant's program provides reasonable assurance that the Limerick EOPs will be consistent with approved technical guidelines and an appropriate writer's guide, (2) that the EOPs will be verified and validated, (3) that the operators will be trained adequately prior to the implementation of EOPs, and (4) that the PGP is acceptable. The staff finds the applicant's response to TAP Item I.C.1 acceptable.

13.6 Physical Security Plan

Introduction

The Philadelphia Electric Company (PECo) filed with the Nuclear Regulatory Commission the following security program plans:

> "Limerick Generating Station Physical Security Plan" dated March, 1981 (letter of March 17, 1981) as revised by changes dated May, 1983 (letter of May 20, 1983) and August, 1983 (letter of September 8, 1983), August 1984 (letter of August 31, 1984); and September 1984 (letter of September 25, 1984) "Limerick Generating Station Safeguards Contingency Plan", dated March, 1981 (letter of March 17, 1981) as revised by change dated April, 1982 (letter of April 16, 1982); "Limerick Generating Station Plant Security Personnel Training and Qualification Plan", dated September, 1981 (letter of September 30, 1981) as revised by change dated March, 1982 (letter April 1, 1982) and August, 1982 (letter of August 13, 1982).

This Safety Evaluation Report (SER) summarizes how the applicant has provided for meeting the requirements of 10 CFR Part 73. The SER is composed of a basic analysis that is available for public review, a protected Appendix, and a protected response force size worksheet.

Based on a review of the subject documents and visits to the site, the staff has concluded that the protection provided by the Philadelphia Electric Company against radiological sabotage at the Limerick Generating Station meets the requirements of 10 CFR Part 73. Accordingly, the protection will ensure that the health and safety of the public will not be endangered.

Physical Security Organization

To satisfy the requirements of 10 CFR 73.55(b) the Philadelphia Electric Company has provided a physical security organization that includes a Sergeant of the Guards who is onsite at all times with the authority to direct the physical protection activities. To implement the commitments made in the physical security plan, training and qualification plan, and the safeguards contingency plan, written security procedures specifying the duties of the security organization members have been developed and are available for inspection. The training program and critical security tasks and duties for the security organization personnel are defined in the "Limerick Generating Station Plant Security Personnel Training and Qualification Plan" which meets the requirements of 10 CFR Part 73, Appendix B for the training, equipping and requalification of the security organization members. The physical security plan and the training program provide commitments that preclude the assignment of any individual to a security related duty or task prior to the individual being trained, equipped and qualified to perform the assigned duty in accordance with the approved guard training and qualification plan.

Physical Barriers

In meeting the requirements of 10 CFR 73.55(c) the applicant has provided a protected area barrier which meets the definition in 10 CFR 73.2(f)(1). An isolation zone, to permit observation of activities along the barrier, of at least 20 feet is provided on both sides of the barrier with the exception of the locations listed in the Appendix. The staff has reviewed those locations and determined that the security measures in place are satisfactory and continue to meet the requirements of 10 CFR 73.55(c).

Illumination of 0.2 foot-candles is maintained for the isolation zones, protected area barrier, and external portions of the protected area. In areas where illumination of 0.2 foot-candles cannot be maintained, special procedures are applied as described in the Appendix.

Identification of Vital Areas

Vital equipment is located within vital areas which are located within the protected area and which requires passage through at least two barriers, as defined in 10 CFR 73.2(f)(1) and (2), to gain access to the vital equipment. Vital area barriers are separated from the protected area barrier. The control room and central alarm station are provided with bullet-resistant walls, doors, ceilings, floors, and windows.

Access Requirements

In accordance with 10 CFR 73.55(d) all points of personnel and vehicle access to the protected area are controlled. The individual responsible for controlling the final point of access into the protected area is located in a bullet-resistant structure. As part of the access control program, vehicles (except under emergency conditions), personnel, packages, and materials entering the protected area are searched for explosives, firearms and incendiary devices by electronic search equipment and/or physical search.

Vehicles admitted to the protected area, except licensee designated vehicles, are controlled by escorts. Licensee designated vehicles are limited to on-site station functions and remain in the protected area except for operational maintenance, repair, security and emergency purposes. Positive control over the vehicles is maintained by personnel authorized to use the vehicles or by the escort personnel. A picture badge/key card system, utilizing encoded information, identifies individuals that are authorized unescorted access to protected and vital areas, and is used to control access to these areas. Individuals not authorized unescorted access are issued non-picture badges that indicate an escort is required. Access authorizations are limited to those individuals who have a need for access to perform their duties.

Unoccupied vital areas are locked and alarmed. During periods of refueling or major maintenance, access to the reactor containment(s) is positively controlled by a member of the security organization to assure that only authorized individuals and materials are permitted to enter. In addition, all doors and personnel/equipment hatches into the reactor containment(s) are locked and alarmed. Keys, locks, combinations and related equipment for the protected area are changed on an annual basis. In addition, when an individual's access authorization has been terminated due to the lack of reliability or trustworthiness, or for poor work performance, the keys, locks, combinations and related equipment to which that person had access are changed.

Detection Aids

In satisfying the requirements of 10 CFR 73.55(e) the applicant has installed intrusion detection systems at the protected area barrier, at entrances to vital areas, and at all emergency exits. Alarms from the intrusion detection system annunciate within the continuously manned central alarm station and a secondary alarm station located within the protected area. The central alarm station is located such that the interior of the station is not visible from outside the perimeter of the protected area. In addition, the central station is constructed so that walls, floors, ceilings, doors, and windows are bullet-resistant. The alarm stations are located and designed in such a manner so a single act cannot interdict the capability of calling for assistance or responding to alarms. The central alarm station contains no other functions or duties that would interfere with its alarm response function. The intrusion detection system transmission lines and associated alarm annunciation hardware are self-checking and tamper-indicating. Alarm annunciators indicate the type of alarm and its location when activated. An automatic indication of when the perimeter alarm system is on standby power is provided in the central alarm station.

Communications

As required in 10 CFR 73.55(f) the applicant has provided for the capability of continuous communications between the central and secondary alarm station operators, guards, watchmen, and armed response personnel through the use of a conventional telephone system, and a security radio system. In addition, direct communication with the local law enforcement authorities is maintained through the use of a conventional telephone system and two-way FM radio links. All non-portable communication links, except the conventional telephone system, are provided with an uninterruptible emergency power source.

Test and Maintenance Requirements

In meeting the requirements of 10 CFR 73.55(g) the applicant has established a program for the testing and maintenance of all intrusion alarms, emergency alarms, communication equipment, physical barriers and other security related devices and equipment. Equipment or devices that do not meet the design performance criteria or have failed to otherwise operate will be compensated for by appropriate compensatory measures as defined in the "Limerick Generating Station Security Plan" and in site procedures. The compensatory measures defined in these plans will assure that the effectiveness of the security system is not reduced by failures or other contingencies affecting the operation of the security related equipment or structures. Intrusion detection systems are tested for proper performance at the beginning and end of any period that they are used for security. Such testing will be conducted at least once every 7 days.

Communication systems for onsite communications are tested at the beginning of each security shift. Offsite communications are tested at least once each day.

Audits of the security program are conducted once every 12 months by personnel independent of site security management and supervision. The audits, focusing on the effectiveness of the physical protection provided by the onsite security organization implementing the approved security program plans, include, but are not limited to: a review of the security procedures and practices; system testing and maintenance programs; and local law enforcement assistance agreements. Quality assurance and corporate security personnel prepare a report documenting audit findings and recommendations.

Response Requirements

In meeting the requirements of 10 CFR 73.55(h) the applicant has provided for armed responders immediately available for response duties on all shifts consistent with the requirements of the regulations. Considerations used in support of this number are attached (see Appendix). In addition, liaison with local law enforcement authorities to provide additional response support in the event of security events has been established and documented.

The applicant's safeguards contingency plan for dealing with thefts, threats and radiological sabotage events satisfies the requirements of 10 CFR Part 73, Appendix C. The plan identifies appropriate security events which could initiate a radiological sabotage event and identifies the applicant's preplanning, response resources, safeguards contingency participants and coordination activities for each identified event. Through this plan, upon the detection of abnormal presence or activities within the protected or vital areas, response activities using the available resources would be initiated. The response activities and objectives include the neutralization of the existing threat by requiring the response force members to interpose themselves between the adversary and their objective, instructions to use force commensurate with that used by the adversary, and authority to request sufficient assistance from the local law enforcement authorities to maintain control over the situation. To assist in the assessment/response activities a closed circuit television system, providing the capability to observe the entire protected area perimeter, isolation zones and a majority of the protected area, is provided to the security organization.

Employee Screening Program

In meeting the requirements of 10 CFR 73 55(a) to protect against the design basis threat as stated in 10 CFR 73 1 (a)(1)(ii), the Philadelphia Electric Company has provided an employee screening program. Personnel who successfully complete the employee screening program or its equivalent may be granted unescorted access to protected and vital areas at the Limerick site. All other personnel requiring access to the site are escorted by persons authorized and trained for escort duties and who have successfully completed the employee screening program.

The employee screening program is based upon accepted industry standards and includes a background investigation, a psychological evaluation, and a continuing observation program. In addition, the applicant may recognize the screening program of other nuclear utilities or contractors based upon a comparability review conducted by the Quality Assurance Division. The plan also provides for a "grandfather clause" exclusion which allows recognition of a certain period of trustworthy service with the utility or contractor, as being equivalent to the overall employee screening program. The staff has reviewed the applicant's screening program against the accepted industry standards (ANSI N18.17 1973) and has determined that the Philadelphia Electric Company program is acceptable.

15 ACCIDENT ANALYSES

15.8 Anticipated Transients Without Scram

The staff stated in the Safety Evaluation Report (SER) that Generic Letter 83-28 "Required Actions Based on Generic Implications at Salem ATWS Events" had been issued on July 8, 1983 and that the staff would report the results of its review of the applicant's response in a supplement to the SER.

The applicant in its November 10, 1983 and May 8, 1984 letters, has provided responses to Generic Letter 83-28. The staff has performed a preliminary technical assessment and has determined that the applicant has addressed all the applicable issues in Generic Letter 83-28 and that the schedule to submit responses and implement the requirements of Generic Letter 83-28 is acceptable.

The submittal of the remaining responses to and implementation of the requirements of Generic Letter 83-28 on a schedule consistent with that given in the applicant's November 10, 1983 and May 8, 1984 letters, shall be made a condition of the license. Accordingly this issue is closed for the purposes of issuance of the operating license.

15.9 TMI Action Plan Requirements

15.9.3 II.K.1, IE Bulletins on Measures to Mitigate Small Break LOCAs and Loss-of-Feedwater Accidents

II.K.1.10 Review and Modify (As Required) Procedures for Removing Safety-Related Systems from Service (and Restoring to Service) To Assure Operability Status Is Known

In the SER the staff noted as a confirmatory item that it would verify that administrative procedures addressing the release from service and return to service of safety related equipment had been written to address the requirements of IE Bulletin 79-08, Item 8.

The NRC Region I office conducted inspections of the applicant's response to IE Bulletin 79-08, Item 8 and reported the results in Inspection Report 50-352/84-19 and 50-353/84-06 as transmitted by letter to the applicant on May 21, 1984. The portion of the report addressing this issue is as follows:

> (Closed) II.K.1.10 Operability Status
>
> In section 1.13 of the FSAR, the licensee committed to implement an Administrative Procedure to address Item 8 of IE Bulletin, 79-08, the IE Bulletin discussed actions to: (1) verify by test or inspection the operability of redundant safety-related systems upon their restoration to service following maintenance or testing; and (3) notify reactor operational personnel whenever a safety-related system is removed from and returned to service.

Procedure A-41, Procedure for Control of Safety-Related Equipment, has been approved and issued. In A-41, those actions necessary to comply with Item 8 of IEB 79-08 are described. The actions include charging the shift superintendent with overall responsibility for maintaining cognizance and control of the operability status of safety-related equipment. Further, the procedure establishes verifications of redundant system operability and of system restorations after maintenance and testing. Additionally, A-41 establishes a status sheet maintained by the control operator and the assistant control operator to track the status of systems undergoing tests.

Conclusions

On the basis discussed above the staff concludes that this issue is closed.

15.9.4 II.K.3 Final Recommendation of B&O Task Force

II.K.3.13 Separation of High Pressure Coolant Injection and Reactor Core Isolation Cooling System Initiation Levels

In the SER the staff noted as a confirmatory item that it would verify the installation of equipment for the automatic restart of RCIC on low water level before an operating license was issued. The applicant confirmed by letter dated May 22, 1984 that the modifications to provide automatic restarting of RCIC at low water level had been installed and therefore the staff considers this confirmatory item to be closed.

II.K.3.15 Modify Break Detection Logic to Prevent Spurious Isolation of High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems

In the SER the staff noted as a confirmatory item that it would verify the installation of modifications to the HPCI/RCIC steamline isolation logic to address the spurious isolation of these systems as a result of the pressure spike that accompanies their startup. The applicant confirmed by letter dated May 22, 1984 that the modifications discussed in the SER (the addition of a time delay to the HPCI/RCIC high flow trip logic) had been completed and therefore the staff considers this confirmatory item to be closed.

II.K.3.31 Plant-Specific Calculations To Show Compliance With 10 CFR 50.46

The SER stated that the applicant had committed to supply plant-specific LOCA analyses and that the staff would report its review in a supplement. As stated in Section 6.3.5 of this supplement, the applicant has provided this information and the staff finds it acceptable. Therefore, the staff finds as well that the requirements of TMI Action Item II.K.3.31 have been satisfied and this confirmatory issue is closed.

APPENDIX A

CONTINUATION OF CHRONOLOGY OF RADIOLOGICAL REVIEW FOR THE LIMERICK GENERATING STATION

October 25, 1983	Letter from applicant on NUREG-0737, Supplement 1 requirements.
October 25, 1983	Letter from applicant on low frequency content of SRV loading.
October 28, 1983	Letter from applicant on shift turnover procedures.
October 31, 1983	Letter from applicant on revision 4 to fire protection evaluation report.
November 4, 1983	Letter from applicant on feedwater containment isolation check valves.
November 7, 1983	Letter from applicant on Mark III Humphrey concerns.
November 7, 1983	Letter from applicant on fatigue effects due to SRV loads.
November 7, 1983	Letter from applicant on meteorological data.
November 8, 1983	Letter from applicant on structural steel fire protection.
November 10, 1983	Letter from applicant on Generic Letter 83-28, Salem ATWS event.
November 23, 1983	Letter from applicant on cable and cable tray fire protection.
November 25, 1983	Letter to applicant on control room design review.
November 28, 1983	Letter from applicant on alternate shutdown cooling mode.
November 30, 1983	Letter from applicant on solid radwaste process control system.
November 30, 1983	Letter from applicant on emergency plan implementing procedures.
December 6, 1983	Letter to applicant on seismic/dynamic review site audits.
December 12, 1983	Letter from applicant on emergency plan implementing procedures.

December 15, 1983	Letter to applicant on Salem ATWS event (Generic Letter 83-28).
December 19, 1983	Letter from applicant on facility staffing.
December 19, 1983	Letter to applicant on environmental qualification.
December 28, 1983	Letter from applicant on UT process for RPV for Regulatory Guide 1.150.
January 1, 1984	Letter from applicant on structural steel fire protection.
January 10, 1984	Letter to applicant on design verification program.
January 13, 1984	Letter from applicant on structural steel fire protection.
January 16, 1984	Letter from applicant on environmental qualification of equipment.
January 18, 1984	Letter from applicant in response to ACRS concerns.
January 19, 1984	Letter from applicant on procedures generation package.
January 19, 1984	Letter from applicant with proposed Technical Specifications.
January 30, 1984	Letter from applicant on qualification of ADS accumulators.
February 1, 1984	Letter to applicant on control system failures.
February 6, 1984	Letter to applicant on control of heavy loads program, Phase II.
February 9, 1984	Letter to applicant on deletion of data from emergency plan.
February 9, 1984	Letter to applicant on fire protection for structural steel.
February 15, 1984	Letter from applicant on preservice inspection program.
February 15, 1984	Letter from applicant on instrument air cleanliness.
February 16, 1984	Letter from applicant on environmental qualification of equipment.
February 16, 1984	Letter from applicant on cable and cable tray fire protection.
February 21, 1984	Letter from applicant on administrative controls for fire protection.

February 21, 1984	Letter from applicant on loose parts monitoring system.
February 27, 1984	Letter from applicant on meteorological data.
February 29, 1984	Letter to applicant on SGTS filters.
February 29, 1984	Letter from applicant on structural steel fire protection.
March 13, 1984	Letter from applicant on seismic/dynamic qualification of equipment.
March 22, 1984	Letter from applicant on ultimate heat sink extreme wind hazard analysis.
March 26, 1984	Letter from applicant on independent design verification program.
April 2, 1984	Letter from applicant on containment emergency sump performance.
April 4, 1984	Letter from applicant on operating shift experience information.
April 5, 1984	Letter from applicant on pump and valve operability review.
April 6, 1984	Letter from applicant on environmental qualification of equipment.
April 11, 1984	Letter from applicant on project schedule.
April 13, 1984	Letter from applicant on standby gas treatment system.
April 18, 1984	Letter from applicant on testing of MSIV-LCS.
April 23, 1984	Letter from applicant on annual report.
April 27, 1984	Letter from applicant on drywell spray actuation effects.
April 30, 1984	Letter from applicant on hydrogen recombiner leakage testing.
April 30, 1984	Letter to applicant on Regulatory Guide 1.97 review.
May 2, 1984	Letter from applicant on FSAR Q-List.
May 3, 1984	Letter from applicant on independent design verification program.
May 4, 1984	Letter from applicant on high energy line break/control systems failure analysis.

May 8, 1984	Letter from applicant on Generic Letter 83-28, Salem ATWS Event.
May 8, 1984	Letter from applicant on emergency planning.
May 8, 1984	Letter from applicant on independent design verification program.
May 9, 1984	Letter to applicant on II.F.1 and III.D.1.1.
May 15, 1984	Letter from applicant on meteorological data.
May 15, 1984	Letter to applicant on independent design verification program.
May 16, 1984	Letter from applicant on instrument air cleanliness.
May 16, 1984	Letter from applicant on reactor enclosure crane.
May 18, 1984	Letter from applicant on physical security plan.
May 18, 1984	Letter from applicant on electrical raceway separation criteria Wyle test report.
May 22, 1984	Letter from applicant on HPCI and RCIC logic.
May 25, 1984	Letter from applicant on fracture toughness of feedwater isolation check valves.
May 25, 1984	Letter from applicant on procedures for isolating feedwater bypass lines.
May 25, 1984	Letter from applicant on systems shared between Unit 1 and Unit 2.
May 25, 1984	Letter from applicant on project schedule.
May 31, 1984	Letter from applicant on structural steel fire protection.
May 31, 1984	Letter to applicant on safety parameter display system.
May 31, 1984	Letter to applicant on operating shift staffing experience.
June 1, 1984	Letter from applicant on emergency planning.
June 4, 1984	Letter from applicant on standby gas treatment system demisters.
June 5, 1984	Letter from applicant on control systems failures.
June 6, 1984	Letter from applicant on evacuation time estimates.

June 6, 1984	Letter from applicant on test and construction item deferrals.
June 6, 1984	Letter from applicant on independent design verification program.
June 7, 1984	Letter from applicant on FSAR Tables 3.2-1 and 3.2-2.
June 7, 1984	Letter from applicant on GE and Love model isolators.
June 11, 1984	Letter to applicant on mechanical engineering items.
June 11, 1984	Letter to applicant on environmental qualifications.
June 15, 1984	Letter from applicant on emergency procedures.
June 15, 1984	Letter from applicant on revision 4 of the pump and valve inservice testing program.
June 20, 1984	Letter from applicant on independent design verification program.
June 21, 1984	Letter from applicant on fire protection item deferrals.
June 21, 1984	Letter to applicant on control room design review.
June 21, 1984	Letter from applicant on qualification of ADS accumulators.
June 22, 1984	Letter from applicant on safety relief valves.
June 25, 1984	Letter from applicant on control room design report.
June 27, 1984	Letter from applicant on containment hydrogen recombiners.
July 2, 1984	Letter to applicant on safety parameter display system.
July 6, 1984	Letter from applicant on post accident sampling system.
July 9, 1984	Letter from applicant on emergency planning.
July 9, 1984	Letter to applicant on independent design verification program.
July 10, 1984	Letter from applicant on containment isolation valves.
July 16, 1984	Letter to applicant on offsite dose calculation manual.
July 17, 1984	Letter from applicant on preservice inspection program.
July 17, 1984	Letter from applicant on preoperational tests and construction item schedule deferrals.

July 20, 1984	Letter from applicant on safety parameter display system.
July 20, 1984	Letter from applicant on independent design verification program.
July 23, 1984	Letter from applicant on schedule for fuel loading.
July 24, 1984	Letter from applicant on environmental qualification of equipment.
July 25, 1984	Letter from applicant on use of lifted leads and jumpers during testing.
July 26, 1984	Letter from applicant on standby gas treatment system.
July 27, 1984	Letter from applicant on quantifying releases (II.F.1).
July 27, 1984	Letter from applicant on analysis of tornado missile effects on ultimate heat sink.
July 31, 1984	Letter to applicant on draft Technical Specifications.
August 1, 1984	Letter from applicant on shared systems.
August 1, 1984	Letter from applicant on seismic/dynamic qualification of RCIC turbine.
August 2, 1984	Letter from applicant on seismic qualification of containment vent and purge valves.
August 2, 1984	Letter from applicant on standby gas treatment system drawdown time.
August 2, 1984	Letter from applicant on containment venting pressure.
August 3, 1984	Letter from applicant on schedule for fuel loading.
August 7, 1984	Letter from applicant on mechanical snubber testing.
August 7, 1984	Letter from applicant on revisions to relief request for preservice inspection program.
August 7, 1984	Letter from applicant on emergency plan implementing procedures.
August 8, 1984	Letter from applicant responding to staff June 11, 1984 letter on mechanical engineering items.
August 8, 1984	Letter from applicant on fire sprinkler system installation schedule.
August 8, 1984	Letter from applicant on structural steel fire protection.

August 8, 1984	Letter from applicant on fire protection information for the 4KV bus duct penetrations.
August 10, 1984	Letter from applicant on instrumentation setpoints.
August 13, 1984	Letter from applicant with final report on control of heavy loads.
August 14, 1984	Letter from applicant on fuel handling accident.
August 15, 1984	Letter from applicant on the offsite dose calculation manual.
August 15, 1984	Letter from applicant on meteorological data.
August 16, 1984	Letter from applicant on response to Regulatory Guide 1.97, Revision 2.
August 16, 1984	Letter from applicant on control room design review.
August 16, 1984	Letter from applicant on Wyle test report on electrical separation verification testing.
August 17, 1984	Letter from applicant fuel rod pressure.
August 17, 1984	Letter from applicant on noble gas effluent monitor.
August 20, 1984	Letter from applicant on emergency plan implementing procedures.
August 21, 1984	Letter from applicant on operating shift staffing information in response to staff's May 31, 1984 letter.
August 21, 1984	Letter from applicant on diesel oil storage tank vent lines.
August 22, 1984	Letter from applicant on fire door fusible links.
August 23, 1984	Letter from applicant on preservice inspection program relief requests.
August 23, 1984	Letter from applicant on solid radwaste process control system.
August 24, 1984	Letter from applicant on III.D.1.1, Primary Coolant Outside Containment.
August 24, 1984	Letter from applicant on security provisions for RHR and emergency service water.
August 27, 1984	Letter from applicant on HVAC filter testing.

August 28, 1984	Letter from applicant on operating shift staffing.
August 28, 1984	Letter from applicant on preservice inspection program relief requests.
August 30, 1984	Letter from applicant on redundant reactivity control system.
August 30, 1984	Letter from applicant on periodic review of administrative procedures.
August 31, 1984	Letter from applicant on Generic Letter 83-28, Salem ATWS Event.
September 4, 1984	Letter from applicant on extreme wind hazard analysis.
September 4, 1984	Letter from applicant on pressure isolation valve leakage testing.
September 6, 1984	Letter from applicant on pump and valve operability qualifications.
September 6, 1984	Letter from applicant on RHR service water radiation monitor.
September 6, 1984	Letter from applicant on containment pressure boundary fracture toughness (GDC-51).
September 6, 1984	Letter from applicant on lifted leads and jumpers.
September 7, 1984	Letter from applicant on containment pressure boundary fracture toughness (GDC-51).
September 7, 1984	Letter from applicant on bounding environmental qualification drywell temperature profile.
September 7, 1984	Letter from applicant on Nuclear Review Board.
September 10, 1984	Letter from applicant on process computer system testing.
September 10, 1984	Letter from applicant on seismic/dynamic qualifications.
September 10, 1984	Letter from applicant on qualification of safety-related electrical equipment.

APPENDIX C

UNRESOLVED SAFETY ISSUES

APPENDIX C
UNRESOLVED SAFETY ISSUES

C.4 Discussion of USIs As They Relate to Limerick Units 1 and 2

Task A-43 Containment Emergency Sump Reliability

In the SER the staff discussed the potential for blockage of the RHR suction strainers due to the nature of the fibrous insulation used specifically in the Limerick drywell. The applicant has responded to the concern by letter from J. S. Kemper to A. Schwencer dated April 2, 1984, "Limerick Generating Station, Units 1 and 2 Containment Emergency Sump Performance." The staff has reviewed that submittal and finds that the conclusion reached, based on the most conservative analysis assumptions, is acceptable. It is the staff's view that the submitted calculated results shown in Table 3.2, those which assume "100% fibrous debris migration to the ECCS strainer," do represent the worst case condition. Given such an assumption, and since those calculations show an available NPSH margin of 7 ft of water, or more, we believe that LOCA-generated debris effects will not result in loss of long-term recirculation capability. Our position regarding USI A-43 in the Limerick SER is modified to reflect the information from the April 2, 1984 submittal, and this issue identified in the SER is closed. Thus, the staff concludes that there is reasonable assurance that Limerick can be operated pending ultimate resolution of this generic issue without endangering the health and safety of the public.

APPENDIX H

NRC STAFF CONTRIBUTORS AND CONSULTANTS

APPENDIX H

NRC STAFF CONTRIBUTORS AND CONSULTANTS

This supplement to the Safety Evaluation Report is a product of the NRC staff. The NRC staff members listed below were principal contributors to this report.

NRC STAFF

Name	Title	Branch
J. Ridgely	Mechanical Engineer	Auxiliary Systems
F. Eltawila	Senior Containment Systems Engineer	Containment Systems
A. Gill	Reactor Fuels Engineer	Core Performance
A. Masciantonio	Equipment Qualification Engineer	Equipment Qualification
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R. Kirkwood	Principal Mechanical Engineer	Mechanical Engineering
R. Eberly	Fire Protection Engineer	Chemical Engineering
L. Reiter	Section Leader	Geosciences
D. Smith	Materials Engineer	Materials Engineering
M. Virgilio	Sr. Reactor Engineer	Instrumentation and Control Systems
Y. Hsii	Nuclear Engineer	Core Performance
L. Phillips	Section Leader	Core Performance
W. Kennedy	Operational Safety Engineer	Procedures and Systems Review
M. McCoy	Nuclear Systems Engineer	Procedures and Systems Review
A. Serkiz	Task Manager	Generic Issues

APPENDIX K

MATERIALS SUPPLIED TO NUCLEAR INDUSTRY COMPANIES BY RAY MILLER, INC. AND TUBE-LINE CORPORATION

APPENDIX K

MATERIALS SUPPLIED TO NUCLEAR INDUSTRY COMPANIES BY RAY MILLER, INC. AND TUBE-LINE CORPORATION

As stated in Supplement No. 1 to the staff's SER, on July 22, 1983, the NRC Office of Inspection and Enforcement (IE) issued two IE Bulletins that dealt with similar problems to holders of operating licenses or construction permits. The firms identified in the Bulletins had been involved in supplying substandard materials to nuclear industry companies. These firms were Ray Miller, Inc. and the Tube-Line Corporation.

In IE Bulletins 83-06 ("Nonconforming Materials Supplied by Tube-Line Corporation Facilities") and 83-07 ("Apparently Fraudulent Products Sold by Ray Miller, Inc."), licensees/applicants were requested to identify materials supplied by these companies, and either discard these materials if they are used in safety-related systems or perform prescribed tests and inspections. Written reports describing actions taken in response to these bulletins were requested within 120 days for IE Bulletin 83-06 (Tube-Line) and within 8 months for IE Bulletin 83-07 (Ray Miller).

1. <u>IE Bulletin 83-06 (Tube-Line)</u>

The NRC Region I office conducted inspections of the applicant's response to IE Bulletin 83-06 and reported the results in Inspection Reports 50-352/84-14 and 50-353/84-04 as transmitted by letter to the applicant on April 20, 1984. The portions of the report addressing this issue are as follows:

<u>Followup on IE Bulletins</u>

The licensee's response to the IE Bulletins discussed below was reviewed to assure that the response was timely, complete, technically adequate, and accurately reflected those corrective actions actually performed. No violations were identified.

<u>(Closed) IE Bulletin 83-06</u>: Nonconforming Materials Supplied by Tube-Line Corporation Facilities at Long Island City, New York; Houston, Texas; and Carol Stream, Illinois.

This Bulletin described quality problems associated with carbon steel and stainless steel materials supplied to the nuclear industry. The New York and Texas facilities dealt with carbon steel products; the Illinois facility provided stainless steel products. The problems identified with Tube-Line (T-L) included improper qualification of material and service vendors and improper certification of products shipped from T-L. Licensees were requested to determine if T-L products were installed or on hand for use in safety-related applications, to provide a list of T-L-supplied materials and systems in which the material was installed, to implement a program which would provide assurance that materials received from T-L complied with ASME Code Section III or demonstrates T-L materials were suitable for their use and to replace fittings and flanges which were not in compliance with the ASME Code.

The licensee responded to the Bulletin in letters of December 22, 1983 and February 16, 1984. The responses indicated that only one of the 415 vendors who provided material for various Bechtel projects during the time period in question delivered T-L material to Limerick: Guyon Alloys, Inc. of Harrison, New Jersey.

The inspector reviewed the list of materials provided in a Guyon letter attached to the licensee's response and reviewed the licensee's response to determine the disposition of the materials. He determined that one flange had been provided which was a welded-with-filler-metal item (8", 150# SA-182 Grade F304 RF Blind Flange of T-L heat code ABXA). The balance of the material were fittings fabricated out of either SA-240 or SA-312 base materials.

Based on the licensee's response, on discussions with licensee construction and quality assurance personnel and on record review, the inspector determined that all SA-240 (welded-with-filler-metal items) had been quarantined for return to T-L with the exception of one 4" 90° elbow which is installed in the nonsafety-related fuel pool demineralizer system, 10 3" caps, and the 8" flange. Replacement materials for those to be returned were obtained through Guyon from the Gulf and Western-Taylor Company.

The SA-312 base material fittings supplied by T-L were accepted for use per Bechtel Specification P-309. All except one fitting were still in the warehouse evaluated as suitable for ASME Code use, but not assigned to a system. The one exception involved a 3" 45° elbow installed in a nonsafety-related section of the standby liquid control system (3" HCD 101-2-suction to SLCS pump from the test tank).

The NRC inspector inquired regarding the basis used for acceptance of the SA-240 and SA-312 items. He determined that the basis involved a review of vendor (T-L)-supplied documentation. The inspector stated that quality problems identified in the Bulletin make the validity of vendor-supplied documentation suspect. Accordingly, the licensee's representatives agreed to reevaluate this approach.

The licensee issued NCR 9819 to allow the Tube-Line material which had been released for use in ASME systems to be reevaluated. The disposition of this NCR was to return all those SA-312 and SA-240 items to the supplier.

The inspector had no further questions.

2. <u>IE Bulletin 83-07 (Ray Miller, Inc.)</u>

The NRC Region I office conducted inspections of the applicant's response to IE Bulletin 83-07 and reported the results in Inspection Reports 50-352/84-19 and 50-353/84-06 as transmitted by letter to the applicant on May 21, 1984. The portions of the report addressing this issue are as follows:

Followup on IE Bulletins

The licensee's response to the following IE Bulletins was reviewed to assure that the response was timely, complete, technically adequate, and accurately reflected those actions actually performed.

(Closed) IE Bulletin 83-07: Apparently Fraudulent Products Sold by Ray Miller, Inc.

This IE Bulletin dealt with misrepresentation of the characteristics of products supplied to the nuclear industry by Ray Miller, Inc. The licensee responded to this Bulletin on March 22, 1984, and indicated there were no Ray Miller-supplied products used at the Limerick Generating Station. This result was obtained based on reviews conducted by Bechtel Power Corporation, General Electric, and Philadelphia Electric.

The inspector discussed Bechtel Power Corporation's actions with a licensee representative to determine the methods used for Bechtel's review. The licensee's representative indicated that Bechtel handled this activity generically for all Bechtel sites (e.g., Limerick, Hope Creek, Susquehanna, etc.). Bechtel identified 455 vendors who have provided material to various projects. Each of these vendors received questionnaires from Bechtel, 70 percent of which responded. These responses were then reviewed and evaluated. For the remaining 30 percent, the vendors were contacted by telephone and, for some, Bechtel Field Supplier Quality Representatives visited the facilities and reviewed records. For the remainder who did not respond to the questionnaire or to the followup visit by Bechtel representatives, a Bechtel site document review group reviewed vendor documentation packages on file at Limerick. In no case was any evidence found that indicated involvement by Ray Miller, Inc.

The inspector had no further questions.

3. Conclusions

On the bases discussed above, the staff concludes that these issues are closed.

APPENDIX L

PUMPS AND SPARE PARTS MANUFACTURED BY THE HAYWARD TYLER PUMP COMPANY

APPENDIX L

PUMPS AND SPARE PARTS
MANUFACTURED BY THE HAYWARD TYLER PUMP COMPANY

As stated in Supplement No. 1 to the staff's SER on May 13, 1983 the NRC Office of Inspection and Enforcement issued IE Bulletin 83-05 to holders of operating licenses or construction permits. Supplement No. 1 noted that the staff was evaluating the applicant's response to the bulletin.

The NRC Region I office has since conducted inspections of the applicants response and has reported the results in two inspection reports. The portions of these reports addressing this issue are as follows.

Inspection Report 50-352/84-01

(Open) IEB 83-05 ASME Nuclear Code Pumps and Spare Parts Manufactured by the Hayward Tyler Pump Company

This IEB requested licensees to report all pumps supplied by Hayward Tyler which are used for safety-related purposes, to perform special pump break-in tests on any of these safety-related pumps, to identify any spare parts received from Hayward Tyler and to establish appropriate test programs for these parts.

The licensee responded in letters dated 8/30/83 and 9/1/83, indicating the only pumps subject to the bulletin requests were the two safeguard fill pumps for each unit and the only spare parts in inventory were gaskets. For the pumps, the licensee committed to perform the extended tests during the pre-opertional test phase. The spare gaskets on hand were discarded.

The inspector reviewed technical test TT 1.11 which would be used to perform the extended break-in test and found it to be responsive to the IEB specifications. However, the procedure had not yet been performed. The inspector also confirmed that the spare gaskets had been discarded, but there was no system in place to assure future spare parts received from Hayward Tyler would be subjected to the tests discussed in the IEB. However, the inspector determined that the company was currently not on the licensee's approved vendor list for procurements during plant operations.

This IEB will remain open pending (1) successful completion of TT 1.11 and (2) development of a system to assure future spare parts acquired from Hayward Tyler would be subject to those tests discussed in the bulletin.

Inspection Report 84-43

(Closed) IEB 83-05: Hayward Tyler Pumps and Parts

This bulletin informed licensees of potentially defective components provided by Hayward Tyler Company. The licensee was requested to perform a review to determine if Hayward Tyler equipment was being used at the facility. If so, the equipment would then have to be subject to an extended preservice testing program.

As indicated in Inspection Report 50-352/84-01, four pumps as some spare gaskets were supplied for use at Limerick by Hayward Tyler. The pumps are the safeguard fill pumps; two per unit. The gaskets supplied were discarded.

For Unit 1, the licensee performed Technical Test TT 1.11 on the two Hayward Pumps on 7/18-20/84. The procedure included those extended break-in tests discussed in the IEB.

The inspector reviewed the results of TT 1.11 which indicated acceptable pump performance. Further, because Hayward Tyler is not currently on the licensee's qualified supplier's list, spare parts cannot be purchased from this company for safety-related uses.

The inspector discussed the need for special tests if Hayward Tyler is placed on the qualified supplier's list in the future. The licensee's actions will be monitored during future inspections of the Quality Assurance Program.

The inspector therefore considers this IEB closed for Unit 1.

Conclusions

On the bases discussed above the staff concludes that these issues are closed.

APPENDIX M

BNL REPORT ON STRUCTURAL
STEEL SURVIVABILITY EVALUATION

EVALUATION OF THE ANALYTICAL FIRE MODELING BY PHILADELPHIA ELECTRIC COMPANY (PECO) IN THEIR FEBRUARY 24, 1984 REVISION 2 SUBMITTAL "STRUCTURAL STEEL SURVIVABILITY EVALUATION FOR LIMERICK GENERATING STATION UNIT 1"

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1. INTRODUCTION

This report contains our evaluation of the fire and structural steel survivability modeling methodology employed by Philadelphia Electric Company (PECO) in their February 24, 1984 Revision 2 Submittal "Structural Steel Survivability For Limerick Generating Station Unit 1." As an alternative to the requirements specified in Section III.G of Appendix R to 10CFR50, PECO purports to provide analysis that justifies exemption from the requirement of providing structural steel fire resistance equivalent to that required of the associated barrier.

To strengthen the justification of the exemptions, PECO's analysis indicates that if cable insulation or lubricating oil ignites, the resulting fires do not yield temperature-time characteristics which will cause the unprotected structural steel to exceed its critical failure temperature. To support this contention, two fire-modeling methodologies are employed. A fully developed enclosure fire model is employed to evaluate the average gas mixture temperature in the enclosure. Local heating effects on steel members are assessed by flame and fire plume impingement calculations. These fire models, together with the determination of the maximum allowable steel temperatures, form the basis of the steel survivability evaluation.

At the outset, we must state that the overall approach decribed and implemented by PECO in their two submittals is technically sound. The fire models employed have been documented in the open literature and the methodology employed by PECO represents a compromise between accuracy in real fire environment simulation and practicality of implementation. Our review indicates that this compromise, in concert with most of the assumptions employed to make the analysis tractable, is biased toward the side of conservatism. In our judgment any further investigation by PECO on the effects of thermal stratification on structural steel response (not addressed in either submittal) would have only provided more completeness in their analysis and would not have markedly affected their conclusions.

To substantiate this general summary statement, we start our detailed review of the reference submittal by first describing, in more depth than above, the modeling process employed by PECO. This is followed by some brief thoughts on the key items we consider as forming the foundation of our appraisal. Sections 4 and 5 give our overall evaluation of the PECO approach based upon a detailed critique, which is provided. Our conclusions are given in Section 6.

It should be pointed out that during a conference call with PECO and their consultant PLC on April 26, 1984, and subsequent calls in response to our questions, the content of a proposed errata was agreed upon to primarily correct errors in the application of the methodology in the Revision 2 submittal. This review presupposes that this errata, including the agreed corrections, is forthcoming.

2. SUMMARY OF THE PECO STRUCTURAL STEEL FIRE RESISTANCE MODELING PROCESS

The general approach taken by PECO to assess the fire exposure of unprotected structural steel members consists of two parts. The first employs a fully developed enclosure fire model consisting of a simplified energy balance of the enclosure air and combustible contents to obtain a gas temperature-time curve for the enclosure. The model makes the simplifying and conservative assumption that there are no convective or radiative losses through the enclosure openings while still allowing air for combustion to enter. Also, no heat losses are assumed to occur through the floor. The enclosure walls and ceiling are assumed thermally thick so that conditions on the unexposed, exterior side have no noticeable effect on its temperature history.

In the fully developed fire model the gas in the enclosure is assumed to be thoroughly mixed and at a single spacially uniform temperature that changes with time. The average temperature failure criteria of the steel is taken as 1100°F. Therefore, if the enclosure gas temperature remains below 1100°F the unprotected steel structure is assumed acceptable and if the gas temperature exceeds 1100°F, the thermal response of the steel subject to the maximum gas temperature for the full duration of the fire is calculated by a transient heat transfer correlation.

Two fixed combustible materials are assumed in the plant. These are cable insulation and lubricating oil. Cable fires are considered either as spreading fires or fires which simultaneously involve all exposed combustibles in the enclosure. Various combinations of available enclosure doorways are assumed to be open to provide ventilation.

The spreading cable fires assume a constant fire size, characterized by the heat output. This size is determined by considering the fire to start at a point source located in the area of heaviest cable concentration in the enclosure. A steady-state cable mass burning rate and a horizontal fire spread rate are determined from cable fire experimental data. Vertical cable flame spread is assumed to be instantaneous. The burn time of the original source fire is then obtained from the cable tray fuel loading and the burn rate. The fire size is determined by considering the amount or area of cabling that will become involved during this source fire burn time for the given spread rate. This cable tray area, together with the tray loading and the heat of combustion of the cabling, give the heat output of fire, which is assumed constant throughout its duration. Since the fire origin is considered to be at the point of highest cable concentration, this will be the largest spreading fire possible. Spreading cable fires are analyzed in areas having large openings to adjacent areas. In these cases consideration of all cables burning simultaneously would have been unrealistic.

The fire heat output thus obtained is for a spreading, fuel controlled fire in which sufficient oxygen is available to sustain this level of combustion. For the cases where all the available cable in the enclosure is assumed to burn instantaneously, the fuel controlled heat output is determined directly from the exposed cable surface area and the heat release rate of the EPR/Hypalon cable (190 kW/m^2).

The PECO analysis investigates the ventilation controlled combustion limit of each fire scenario by use of an empirical relation for the rate of burning which can be supported by the fire induced air flow into the enclosure through the specific openings assumed for each case. If the ventilation limit heat output is less than the fuel controlled heat output, the fire is ventilation controlled and the fire heat output is assumed constant with time at the ventilation controlled limit. This heat output is independent of the type of combustibles. If, on the other hand, the ventilation controlled heat output is larger than the fuel controlled heat output, the fire is fuel controlled and the fire heat output is assumed constant at the fuel controlled value which is a function of the type of fuel burning.

The duration of the fully developed fire is determined by dividing the product of the total cable quantity and its heat of combustion by the previously determined constant fire heat output. A maximum fire duration of three hours is assumed.

Lubricating oil fires are assumed to be pool fires where the entire pool surface burns instantaneously at a steady-state burning rate obtained from test data. The fire heat release rate is obtained from the burning rate and the heat of combustion of lubricating oil.

In each fire area considered the amount of oil in the pool is taken as double the amount in the pumps to account for maintenance activities. For the large amount of oil thus considered, the fires are assumed to be ventilation controlled and the pool fire heat output is independent of the characteristics of the oil or the pool. The fire duration is obtained by dividing the product of the fuel volume and the heat of combustion by the ventilation controlled fire heat output. A three hour maximum is again considered.

Once the fire heat output and duration of either of the two types of cable fires or the oil fires are known, the fully developed fire energy balance model is employed to obtain the spacially averaged temperature-time history of the enclosure gas mixture. If the average gas temperature exceeds 1100°F, a transient heat transfer correlation is used to calculate the temperature response of the steel subjected to the maximum value of the gas temperature for the fire duration. If sprinklers are present in the area no steel response calculation is deemed necessary.

The second modeling process used by PECO to assess the fire exposure of the unprotected steel members considers the localized heating effects of flame or fire plume impingement rather than the overall average gas temperature obtained from the fully developed fire model. For cable trays located within one foot of the bottom of steel beams, the entire length of the beam is assumed subject to a constant temperature of 1500°F for the period of time it takes for the cabling in the tray to burn to completion. Cable trays greater than one foot from the bottom of beams but meeting a criteria, dependent on separation distance and number of trays, are assumed subject to a constant temperature of 1300°F. The separation criteria are:

No. of Trays	Tray-Beam Vertical Separation
1	2 ft.
2	3 ft.
3-5	4 ft.
>5	5 ft.

A transient heat transfer correlation is employed to compute the temperature response of the steel when subject to the 1500°F or 1300°F temperatures for the fire duration. The steel member is then assumed to fail if this steel temperature exceeds the critical steel temperature.

For oil fires, a pool fire plume correlation is used to predict the plume temperature at the bottom of any beams located directly above the pool. The pool area is determined by dividing the ventilation controlled heat output by the free burn, fuel controlled surface heat flux of oil fires as determined by data. The use of this equivalent free burn pool area maximizes the fire heat output and therefore the plume temperature obtained from the steady state correlation. If the plume temperature exceeds the critical temperature of the steel the transient heat transfer correlation is applied to determine if the steel temperature exceeds its critical value.

Critical temperatures for beams and columns have been established in order to compare with the actual temperature attained by the steel in each fire compartment. The survivability of the steel structure depends on whether the actual steel temperature exceeds the critical temperature or not. The critical temperature established for steel beams is a 1100°F cross-section average temperature. For columns a 1000°F cross-sectional average temperature has been established.

Based on the above, the Limerick fire safety evaluation calculates the area gas temperature in the room first. If this gas temperature is less than 1100°F which is considered to be the average critical temperature for the structural steel beams, even for partially or fully composite beams, then the steel structures in the compartment are assumed to survive the fire load predicted for the room. If the gas temperature exceeds 1100°F, a transient heat transfer correlation is used to compute the steel temperature. If this steel temperature is less than 1100°F, then the unprotected beam is deemed acceptable. If the steel temperature exceeds 1100°F protection measures are taken.

Next, the localized peak gas temperatures are determined for the appropriate beams and columns in each enclosure. If the local gas temperatures due to oil fire plumes remain below 1100°F and 1000°F for beam and columns, respectively, the unprotected member is acceptable. If the local gas temperature exceeds the criteria, the transient steel heat transfer calculation is performed assuming that the entire length of structure is subjected to the maximum plume temperature for oil fires or either a temperature of 1500°F or 1300°F for cable fires, where in actuality only a small section would be subjected to localized heating. If the calculated local steel temperature is below the critical, then it is assumed that the structure has not reached its single point failure temperature during the fire exposure period.

Transient combustibles are also considered in both area averaged and local plume heating calculations. A backward type calculation was performed. For area calculations in enclosures with sufficient ventilation, the heat release rate of transient combustibles required to raise the area temperature to 1100°F is determined. For enclosures with limited ventilation the fire duration required to produce an area temperature of 1100°F is determined for a transient combustible fire with the ventilation controlled heat release rate.

For enclosures in which fixed combustibles were sufficient to produce room averaged gas temperature exceeding or approaching 1100°F, no area transient calculation was performed. If a fixed combustible fuel controlled fire resulted in room averaged gas temperatures considerably below 1100°F, the heat balance method is used to obtain the additional heat release of transient combustibles required to reach a temperature of 1100°F for the duration of the fixed combustible fire. If no fixed combustibles were present and sufficient ventilation was available, fire durations of one, two and three hours were assumed and the required transient combustible heat release to reach gas temperatures of 1100°F was determined by the heat balance method. If the ventilation to the enclosure was limited the fire duration was computed rather than the heat release.

For localized heating effects the transient combustibles were assumed to be at floor level and the plume temperatures at the bottom of the steel structures were considered. Again a backward calculation was performed to determine the transient combustible heat release rates which result in plume temperatures of 1100°F, 1300°F and 1500°F at the bottom of steel beams using a steady-state plume correlation. For plume temperatures of 1300°F and 1500°F transient heat transfer calculations were made which determine the times required for the steel to reach 1100°F.

3. BASIC BNL REVIEW PROCESS

The first step in our evaluation process is to assess that the methods employed are technically sound and current. This is accomplished, in part, by a review of the open literature to insure that the methodology employed is at the level of the current state-of-the-art. The submittal is then evaluated for continuity and completeness and an assessment of the accuracy is made using simple audit calculations where plausible. Based on these considerations the overall approach is examined to determine if it will yield realistic or conservative results. Finally, consideration is given to the end use of the results.

As we see it, there are four basic steps required for a rational approach to fire engineering design of structural elements. These include:

a) determination of fire load,
b) determination of gas temperature (local/global) in the fire compartment,
c) determination of maximum steel temperature, and
d) determination of the critical load.

In this last step, the load bearing capacity or the critical load of the steel member, in case of a fire, is determined. The load bearing capacity can be calculated on the basis of the strength and deformation characteristics of steel at elevated temperatures. Design diagrams, from which the critical load can be determined for beams and columns as a function of maximum steel temperature (Step c), are available in the open literature. Thus, by comparing the actual load with the critical load, it can be judged whether or not the structure will fulfill its function during a real fire. In PECO's approach, Step (d) is not done on a case-by-case basis. Instead, information gleaned from the open literature regarding steel temperature versus yield strength is implemented, which, while lacking completeness, in our judgment, is acceptable.

4. SUMMARY EVALUATION OF THE PECO APPROACH

The general approach taken by PECO is to determine the spacially averaged enclosure gas mixture temperature, calculate the temperature response of unprotected steel structures and compare the result to a critical temperature of the steel. Structural steel heating due to local flame or plume impingement is also considered for a class of geometric configurations. For these calculations the transient thermal response of the steel is also determined and compared to a critical temperature of the steel. The quantity of transient combustible material necessary to raise the steel temperature to its critical value is determined in terms of its heat release rate.

The basic modeling employed consists of a fully developed enclosure energy balance, convective fire plume correlations and a ventilation limit heat release rate correlation. These basic models can be classified as current and methodologically consistent with what is suggested in the open literature as a viable approach for assessing the fire hazard potential of the scenarios considered. Thus, if applied properly, we deem the methodology employed as capable of yielding realistic and conservative results. For completeness however, calculations to determine the critical load (Step d, above) would have been beneficial.

Supporting methodology consists of a cable flame spread procedure, a cable flame temperature determination, fire size and enclosure ventilation assumptions and selection of a critical structural steel failure temperature. It is in some of these areas where we find the PECO approach some what incomplete and not as conservative as it could be. These include nonconservative cable fire heat release rates used as input to the energy balance model due to lack of consideration of enclosure feedback effects, secondary fires in spreading cable fire scenarios, limited ventilation by administrative controls and failure to consider cables burning during lube oil fires. The failure to include ceiling stratification and the effects of fires near enclosure walls and corners also adds to the incompleteness. These concerns are enumerated below and described in depth in Section 5.

On the other hand, the conservatisms of the methodology, primarily the assumption of no convective or radiative heat losses through enclosure openings and the doubling of the quantity of oil, tend to counter the nonconservatisms discussed above. With the limited time and resources of this review it is not possible to quantify the sum result of the "plus" and "minuses" of the various assumptions and lack of completeness. Extensive calculations would be required to produce a definitive answer.

Based on this limited review, our conclusion is therefore, that the basic methodology is sound, that its application could be made more conservative and complete, but that in general its application should result in an acceptable evaluation of the survivability of structural steel.

An enumeration of our concerns mentioned above follows with detailed discussions in Section 5.

1. Radiative feedback to the source fire from the hot upper ceiling layer can result in larger mass burning rates and hence different heat release rates than the cable data used in the analysis.

2. Secondary cable tray fires have not been considered in the spreading fire analysis.

3. Dependency has been put upon administrative controls for limiting the amount of ventilation available through open doorways in Calculations No. 1 and 2.

4. In areas where lubricating oil is considered as the primary combustible, the involvement of cable insulation in the fire is not considered.

5. The effects of ceiling stratification have not been considered in the submittal.

6. The effects of fires near enclosure walls or corners have not been considered in evaluating local heating due to cable fires or transient combustibles.

7. The analysis does not consider the load bearing capacity or the critical load of the steel members during a fire as part of the failure criteria.

8. The analysis of local heating of transient combustible fire does not include the effects on structural columns.

9. Areas requiring fire barriers because of the sensitivity of safe shutdown of the plant irrespective of the fire load conditions should be identified.

5. DETAILED EVALUATION OF PECO APPROACH

The modeling employed by PECO is reviewed in four sections. The first assess the fully developed enclosure fire model which determines the spacially averaged enclosure gas mixture temperature-time history. The second assesses the methodology used to determine the local heating effects on the structural members. The third section reviews the rationale used in determining the critical failure temperatures of the structural steel. The final section concerns the quantification of transient combustibles.

5.1 Review of the Fully Developed Fire Modeling

The cable insulation data used in the analysis was taken essentially from a single intermediate-scale stacked tray fire test utilizing EPR/Hypalon cables.(1) The given steady-state mass burning rate of 6.7 kg/min and heat flux of 190 kW/m^2 (1000 Btu/min ft^2) implies use of a heat of combustion of 22.7 kJ/g. This value of heat of combustion is in the range of values reported in Reference (2) by Tewarson for EPR/Hypalon. The value of heat flux of 190 kW/m^2 falls on the low end of the values in Reference (2) for large-scale fires, which range up to 350 kW/m^2.

In spite of this, the cable data used is probably acceptable for the type of intermediate scale tests considered although it is certainly not overly conservative. However, the analysis has failed to consider the important effects of en closure feedback on the fire. For the amount and type of combustibles considered in the calculations with all cables burning a hot, smokey upper layer of combustion products will almost certainly form in the enclosure. Radiation from this hot layer will feedback to the burning object,(3) possibly inducing greater burning rates and a larger heat release than in the intermediate-scale test from which the data was obtained.

For calculations where spreading cable fires are considered, enclosure effects should not be as great since the enclosures for which spreading fires are considered have large openings, precluding the build up of a large smoke layer.

It should also be pointed out that it is not necessary to rely on data for the flame spread rate. Theoretical expressions(4) exist which allow the horizontal flame spread rate to be calculated as a function of the local heat flux and the flame temperature.

For lubricating oil, the data used(5) appears to be sufficiently conservative. The quoted regression rate of 5 mm/min translates into a mass burning rate of 72.6 g/m^2 sec, which is considerably higher than the asymptotic laboratory scale limit of 40 g/m^2 sec suggested in more recent work by Tewarson(6) for high-temperature hydrocarbons. Values for large scale fires would even be lower. The heat of combustion used (149,940 Btu/gal) corresponds to complete combustion on a laboratory scale. Actual values are about 80% of this.(6) The heat release rate obtained by multiplying the burning rate and the heat of combustion used results in 3470 kW/m^2. This can be compared to large scale fire values of 1000 to 1100 kW/m^2 reported in References (6) and (7).

The preceding discussions concerned fuel controlled fires for which there was sufficient oxygen available for the burning rate to be determined by the fuel properties and configuration. For enclosures with limited ventilation, the PECO analysis makes use of an empirical correlation[8] in which the ventilation limited heat release rate is proportional to the enclosure ventilation factor. This factor is the vent opening area times the square root of the vertical height of the opening. If the fuel controlled heat release rate of the fire is less than this ventilation limit heat release rate, the fire is considered fuel controlled. However, if the fuel controlled rate is greater than the ventilation limit rate, the fire is ventilation controlled and the ventilation limited heat release rate is used. This correlation and methodology appears adequate.

A part of the PECO methodology which may be lead to a lower level of conservatism is the determination of the values spreading cable fire heat release rate. The concern is that of secondary fires. The analysis only considers contiguous fire spread to adjacent cables and states this is valid until the spacially averaged room gas temperature reaches the autoignition temperature of the cabling. The inference that secondary, i.e., noncontiguous, cable fires will not initiate until the cable autoignition temperature is reached is not realistic. In nuclear power plants there is always the possibility of pilot fuels such as rags or paper existing in the vicinity of cable trays. These fuels will ignite at much lower temperature than the cable autoignition temperature. This fact, when coupled with data(9) that EPR/Hypalon power cables start to pyrolyze at temperatures of 500°F, lead to the possibility of secondary fires increasing the amount of cabling involved in the spreading fire and therefore increasing the fire heat release rate. PECO relies on data from Reference (2), also taken from Reference (9), which indicates that instrumentation cables of EPR/Hypalon begin to pyrolyze at about 850°F. The most conservative approach is to rely on the lower temperature data, since power cables may exist in these enclosures.

Additionally, there can be local hot spots in the enclosure, where the calculated gas temperature is exceeded, since the energy balance only yields a single spacially averaged enclosure gas temperature. Therefore, secondary fires can initiate at these hot spots before the suggested average gas temperature of 1100°F for model validity is reached. For example, local heating and secondary fires can result from radiation from the hot gas layer to nonburning cabling or by convection to cable trays in the stratification layer near the ceiling.[7] The heat flux in the stratified layer is enhanced further when the original fire is in the vicinity of enclosure walls or corners.[10]

The energy balance used in the fully developed fire methodology to calculate the spacially averaged enclosure gas temperature is similar to that derived by Harmathy[11] except that a constant heat release rate is used. Additional assumptions that there are no heat losses out the openings or to the floor and that the walls are thermally thick are conservative. The resulting expression indicates that the gas temperature is proportional to the product of the heat release rate and the square root of time. This is discussed in a more recent work by Harmathy[12] as being valid for unprotected steel constructions (like those considered by PECO) while for embedded steel construction the dependence is on the product of heat release rate and time. Reference (11) points out that for unprotected steel structures, the maximum steel temperature can be assumed to approximate closely that of the gaseous mixture and that the rise of temperature is more detrimental than the period of time for which the heating is applied. The PECO approach which utilizes a transient heat transfer correlation to compute the steel temperature response to the gaseous temperature is therefore not as conservative as assuming the steel to immediately attain the gas temperature as suggested by Harmathy. However, the fact that PECO employs the maximum gaseous temperature for the entire fire duration, when calculating the heat transfer to the steel, adds back some conservatism. For example, in Calculation No. 1, Case No. 2, the gas temperature reaches 1118°F for a fire duration of 44 minutes, while the steel temperature, using 1118°F as a constant gas temperature, reaches 1094°F in 44 minutes, a difference of only 24°F, but enough to pass an otherwise failed area. In spite of this, on the overall, considering the conservative assumption of no energy loss through enclosure openings, the energy balance methodology would yield more acceptable results if conservative values of fire heat release were used as discussed previously.

It is noted that audit calculations using conservative enclosure structural property data obtained in a conference call with PECO reproduce the energy balance temperature results in Revision 2. This was not the case in Revision 1, indicating that a computation error has been corrected in Revision 2.

In addition to the previously discussed enclosure feedback effects on the cable fire heat release rates, these rates can also be underestimated for certain enclosures where credit is taken for administrative controls on the number of doors that can be open at the same time. This primarily concerns the oil fires in Calculations No. 1 and 2. Other calculations consider less than the maximum number of doors open, but either the steel temperatures already exceed the critical temperature or the fires are fuel controlled.

In Calculations No. 1 and 2, each enclosure has four doors, but only two doors are considered opened. Both fires are ventilation controlled with two open doors, leading to the possibility of higher temperature with additional ventilation. For example, Case No. 2 of Calculation No. 1 considers a ventilation controlled heat flux of 9008 kW with two 3'x7' doors open, resulting in a gas temperature of 1118°F in the 44 minutes it takes for the fire to consume 144 gallons of lube oil. If one of the 3'x5'10" doors was also open, a ventilation controlled heat release rate of about 12,000 kW would result, with a burn time of 30 minutes, yielding a maximum gas temperature of 1200°F. The steel response heat transfer calculation using this gas temperature will result in a steel temperature in excess of 1100°F critical value. Therefore, it is important to assess the effectiveness of the administrative controls in limiting the number of doors which can be open in these two areas.

The above result may appear to contradict the discussion in Reference (11). This can be explained by two factors. First, Reference (11) does not consider a constant heat flux for the duration of the fire as assumed in the submittal and second, the level of ventilation is important. Consider Figure 1, which is a reproduction of Figure 8 of Reference (11). For low ventilated fires the gas temperature does increase with increased ventilation reaching a maximum at values near or greater than the ventilation limit (indicated by the arrows) which depends on the fuel loading. Use could be made of the fact that the maximum temperatures occur at about the same value of ventilation parameter, independent of fuel load, to determine the most severe scenario in a fire area. Figure 8.4 of Reference (13) also illustrates examples of increasing gas temperatures with increased ventilation in ventilation controlled fires.

Spreading cable fires are considered in some areas (Calculations No. 16-20). The rationale for this scenario, rather than the more severe condition of having all the cables burning simultaneously, is that these areas have large openings to the outside. This is acceptable since the hot combustion products should exit the enclosure rather easily, making simultaneous combustion of all fuels unlikely.

For lubricating oil pool fires the flame spread across the pool surface has been assumed instantaneous. In some cases the number of enclosure doors assumed open are limited by administrative controls. The consequences of this assumption were discussed previously. The heat release rate of the fire is assumed to be at the ventilation limit for the chosen opening configuration. The burn time is obtained by dividing this ventilation controlled heat release rate into the total energy available; the oil volume times the heat of combustion (J/gal). This allows use of the heat balance methodology to calculate the average room gas temperature independent of the pool area. The pool area is then determined by equivalencing the area to the area of a fuel controlled fire with a heat release rate at the ventilation controlled limit. This results in the maximum pool area and maximum heat release rate for which the entire pool surface can burn for the ventilation available. The pool area and heat release rate are used in a steady-state plume correlation[14] to compute ceiling plume temperatures for local heating effects. Examination of this correlation shows the temperature to be maximized by use of the largest heat release rate. However, the use of the maximum pool diameter tends to reduce the virtual source height since the heat release rate, which appears to the 0.4 power, is a function of the diameter squared and the first, negative term is a linear function of the diameter. A reduction in positive virtual height will decrease the plume temperature. However, since the difference in powers is small and since the virtual height is subtracted from the larger physical height in the temperature correlation, the heat release rate effects will dominate. To conclude the methodology used to determine oil pool areas will yield conservative results.

Another consideration in the oil fire analysis is the presence of cable trays. These trays can ignite as secondary fires as previously described with regard to spreading cable fires and increase the heat release rate or the burning time of the fully developed fire. This would be especially important in cases where the oil fire temperatures are nearly critical such as Calculation No. 1.

5.2 Review of Local Heating Effects Modeling

Consideration is given in the PECO analysis to localize effects of fire plume impingement on exposed structural steel. For cable tray fires, directly below the steel, a flame temperature of 1500°F is assumed for a distance of one foot above the tray. Trays further than one foot below a beam are considered if they meet a criteria dependent on distance and the number of trays. For trays at distances greater than one foot, the steel is assumed subject to temperatures of 1300°F. These flame region temperatures are appropriate for cables of EPR/Hypalon[1]. The entire length of the beam is subjected to constant temperatures of 1500°F or 1300°F for the length of time it takes the cables in the tray to burn out. This assumption appears conservative since in most cases the cable tray will not run directly under the full length of the beam. However, no consideration has been given to the existence of a ceiling layer, which will cause the entire beam to be subject to elevated temperature. Therefore, the assumption is not conservative to the degree implied in the submittal.

For the localized effects of oil fires, plume correlations reported by Heskested[14] are used to predict the temperatures at the ceiling directly above the pool fire. These correlations are state-of-the-art and have been corrected in Revision 2 to use the convective heat release rate as indicated by the correlation. This methodology will yield conservative plume temperatures when the maximum pool area is used as discussed in the last section.

On the other hand the results will be less conservative if the pool is near a wall or corner of the enclosure. Reference (10) indicates the enhancement of the local plume temperatures due to these effects.

Once the local gas temperature adjacent to the steel is known, a transient heat transfer equation from Reference (16) is used to compute the temperature response of the steel. No substantiation of this correlation is given, but Equation (4-1) of Reference (17) indicates that it is appropriate for systems having negligible internal resistance. Since steel is a good conductor of heat, this assumption should be valid. The coefficient 231 kg/hr m^2 represents the heat transfer coefficient divided by the steel specific heat. For the cable fires, where the beam is located in the flame, less than one foot above the cables, a conservative heat transfer coefficient of 23 $W/m^{2}{}^\circ K$[18] can be used. When divided by a specific heat of 0.11 Cal/gm°K[17], a coefficient of 179 kg/hr m^2 is obtained, showing the correlation to be conservative.

5.3 Review of Critical Steel Temperature Criteria

The critical steel temperature values have been supported by tests performed in Laboratories.[20-22] It has been well understood that the load bearing capacity or the critical load of the steel structure is greatly affected by composite action with concrete as well as the restraint conditions. These effects influence the strength and deformation characteristics of the steel at elevated temperatures and can be assumed as a function of the maximum steel temperature. Design diagrams for which the critical load can be easily and directly determined for simple beams as well as columns as a function of the maximum steel temperature are available in the literature. Thus, by comparing the actual load with critical load, one could establish whether or not the structure will survive during a real fire.

However, for more complicated steel structures, tests as well as analytical approaches are available to determine the critical temperature corresponding to its critical load bearing capacity. It has been concluded(22) from tests that both the composite action as well as the end restraint effects increase the endurance performance of the steel structure under fire. Also, the results have indicated that the magnitude of the applied vertical load is a more significant parameter on fire endurance performance than measured initial working stress. Some researchers(16,21,22) also found that temperature alone does not provide a meaningful index of fire performance. Temperature and the temperature distribution are factors, as are the vertical design loads, which combine with the effects of end restraints to determine the forces and moments to be resisted by the structural assembly. The analytical approaches consider the effects of creep deformation as well as thermal expansion at elevated temperatures and hence, the critical load is to some extent dependent on the final temperature and the heating rate. With the aid of a simplified procedure using basic creep formulations, Hamarthy(21) found that for A36 steel the limiting temperatures usually range between 1074 and 1231°F, depending on the moment of inertia of the steel deck.

Another aspect relevant to the critical temperature of steel structure is the consideration of the yield strength of the material. Steel structures are generally designed on the basis of 60% yield strength as the allowable stress limit. The yield strength versus temperature curves for structural steel, included in the submittal, indicate that the yield strength of the steel at about 1100°F reduces to 60% of that at room temperature. Hence, if a particular steel structure is originally designed at room temperature stress limits for a specific mechanical load, the structure should be able to carry the same load at 1100°F provided local failure does not occur earlier due to thermal buckling.

Recent studies(23,24) of the design of steel structures under fire load have focussed on a probability based procedure. This reliability based design includes the uncertainties inherent in physical phenomena and human behavior, uncertainties associated with the estimation of parameters of statistical distributions representing the variance of material properties and load characteristics and the uncertainty caused by the incompleteness of the mathematical model describing the physical phenomena.

A compilation of the state-of-the-art of reliability-based structural design(13) has been presented at the "Structural Fire Safety" Workshop held in January 1983. Several structural response and heat exposure models are discussed to simulate various fire studies. Some of the examples are published by the Swedish researchers in References(23,24).

Similar studies(25,26) are in progress at the Center for Fire Safety Studies, Worchester Polytechnic Institute, Massachusetts. Computer programs are being examined for analyzing models related to the fire and its propagation, the heat transfer to the structural members and the effect of elevated temperature on structural performance based on creep. Use of these procedures might allow structural fire design to be based on real fire exposure rather than test fire results only.

In the Limerick Fire Resistance of Structural Steel Study, the critical temperatures were selected from the published test data for three distinct steel construction configurations. No specific effort was made to identify the actual critical temperature for each steel structure considered in the fire study. It is to be noted that to enhance analytical completeness the critical steel temperature for each individual steel structure in the plant could have been established based on their actual design configuration, end restraint condition and other relevant parameters. If any steel structure was found different from published test specimens, some sort of justification could have then been included for establishing its individual critical temperature. However, based on the past research, a critical temperature of 1100°F can be used for the sake of implementation practicality.

5.4 Review of Transient Combustible Evaluation

Both the area averaged and local heating effects of transient combustibles are considered. The approach quantifies the size or duration of transient combustible fires which cause the failure criteria to be reached.

For area calculations, where the fixed combustible fire does not produce room averaged gas temperatures in the range of 1100°F, the same heat balance methodology used for the fixed combustibles is employed. It is implied that areas with gas temperatures close to 1100°F will fail due to any transient combustible fire since no calculation is made. For enclosures with sufficient ventilation the heat balance relationship is solved for the heat release rate as a function of a specified burn time and a gas temperature of 1100°F. The burn time is the same as the fixed combustible fire duration or if no fixed combustibles are present, calculations are made for one, two, and three hour fires. In this manner the addition heat release due to transient combustibles required to reach a gas temperature of 1100°F is determined. For enclosures with limited ventilation, the ventilation controlled heat release rate is assumed and the heat balance relationship is used to compute the additional fire duration as a function of this heat release rate and a gas temperature of 1100°F.

Since the same heat balance methodology discussed in Section 5.1 was employed, the quantification of transient combustibles required to reach enclosure gas temperatures should be adequate to give an estimate of the damage potential. It should be noted that although the submittal discusses three area transient combustible calculation categories, only the two discussed here are employed.

The local heating effects of transient combustibles were evaluated using an approximate, empirical, steady-state plume temperature relationship from Reference (10). The combustibles are assumed to be at floor level and the heat release rates of transient combustibles required to produce plume temperatures at the bottom of steel members of 1100°F, 1300°F and 1500°F are determined as a function of the separation distance. This correlation, although approximate, should be sufficient to give an estimate of the quantity of transient combustibles necessary to cause concerns.

Two items were not considered in assessing local heating effects. First, even though the plume relationship includes a factor for including effects of enclosure walls and corners in close proximity to the fire, no consideration was given to these effects. To conservatively consider these effects the reported heat release rates for local transient combustibles should be divided by 2 if the fire is adjacent to a wall or by 4 if the fire is in a corner.

Second, the effects of transient fires on columns is not considered. In assessing the local heating effects of fixed combustibles on columns, only those members in close proximity to fixed combustibles were considered. Since the transient combustibles can occur anywhere and since columns are closer to the floor, some consideration should be given to transient combustible fires adjacent to columns.

6. CONCLUSIONS

For the fully developed fire heat balance model, we feel the basic method is sound and conservatively neglects any losses through enclosure openings. The major shortcoming is due to the use, as input, of cable fire heat release rate data, which does not include enclosure feedback effects.

The localized heating and transient combustible analysis are also basically sound but could be more complete if stratification and wall and corner effects were considered.

A steel failure criteria which includes the concept of critical load would also be more complete, but a critical temperature criteria of 1100°F seems to be accepted in the open literature.

Without performing extensive calculations and under the time and expenditure limits of this review, a quantitative determination of the pros and cons of the various assumptions and omissions cannot be made. However, we conclude that the overall basic methodology is sound, that its application could be made more conservative and complete, but that the results should be appropriate in determining the survivability of structural steel during fire.

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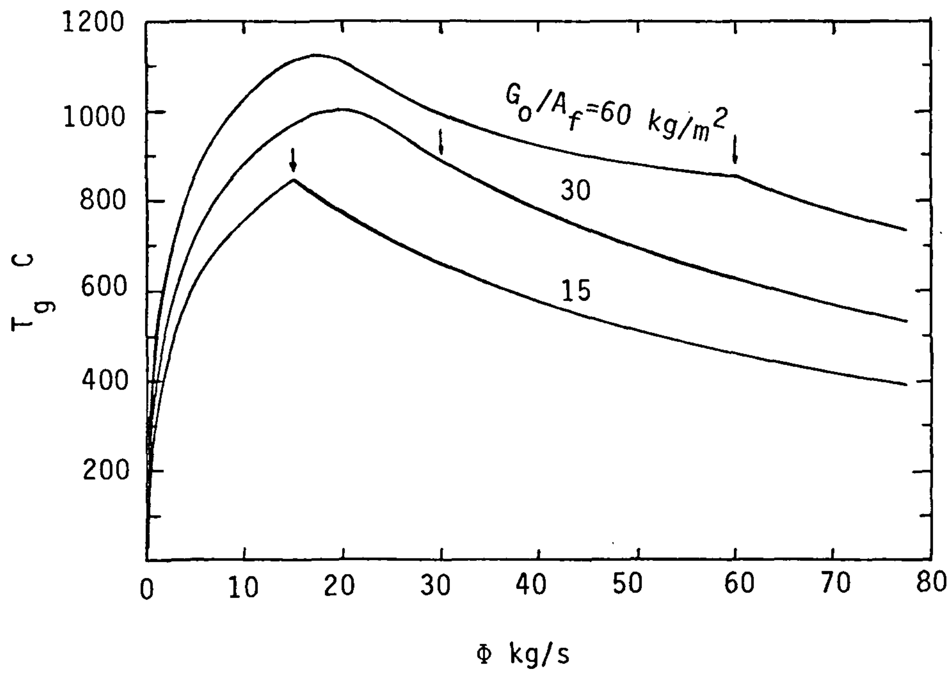

FIGURE 1

THE AVERAGE GAS TEMPERATURE IN THE COMPARTMENT AS A FUNCTION OF THE VENTILATION PARAMETER.

(The arrows indicate the critical values of the ventilation parameter.)

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In August 1983 the staff of the Nuclear Regulatory Commission issued its Safety Evaluation Report (NUREG-0991) regarding the application of the Philadelphia Electric Company (the applicant) for licenses to operate the Limerick Generating Station, Units 1 and 2, located on a site in Montgomery and Chester Counties,Pennsylvania. Supplement 1 to NUREG-0991 was issued in December 1983 and addressed several outstanding issues. Supplement 1 also included the interim report of the Advisory Committee on Reactor Safeguards and the staff's initial response to the comments made in the report. This supplement to NUREG-0991 addresses further issues that require resolution and closes them out.

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