18.0 RESPONSES TO TMI RELATED REQUIREMENTS

This chapter contains a response for each TMI-related requirement. The chapter is divided into sections which contain the responses to all requirements for applicants for operating licenses. The table of contents identifies which section provides the responses for a given document.

Each section addresses all the requirements in its corresponding document. A response is only given to the most recent in the series of requirements which contains an explanatory text. For example, if an explanatory text of requirement I.A.1.1 appears on both NUREG 0737 and NUREG 0694, a response is provided to NUREG 0737 since it supersedes all previous requirements. If requirement I.A.1.2 appears in both NUREGs 0737 and 0694, but the only explanatory text is in NUREG 0694, the response is provided to NUREG 0694 utilizing the implementation dates of NUREG 0737.

These responses are applicable to both Units 1 and 2, however, the equipment identification numbers must be corrected by replacing a Unit 1 designator with a Unit 2 designator. For example, valve HV-15713 in Unit 1 corresponds with HV-25713 in Unit 2, control panel 1C601 corresponds with panel 2C601 in Unit 2.

18.1 RESPONSE TO REQUIREMENTS IN NUREG-0737

18.1.1 Shift Technical Advisor (I.A.1.1)

18.1.1.1 Statement of Requirement

Each licensee shall provide an on-shift technical advisor to the shift supervisor. The shift technical advisor (STA) may serve more than one unit at a multiunit site if qualified to perform the advisor function for the various units.

The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and have received specific training in the response and analysis of the plant for transients and accidents. The STA shall also receive training in plant design and layout, including the capabilities of instrumentation and controls in the control room. The licensee shall assign normal duties to the STAs that pertain to the engineering aspects of assuring safe operations of the plant, including the review and evaluation of operating experience.

The need for the STA position may be eliminated when the qualifications of the shift supervisors and senior operators have been upgraded and the man-machine interface in the control room has been acceptably upgraded. However, until those long-term improvements are attained, the need for an STA program will continue.

The staff has not yet established the detailed elements of the academic and training requirements of the STA beyond the guidance given in the Vassallo letter on November 9, 1979. Nor has the staff made a decision on the level of upgrading required for licensed operating personnel and the man-machine interface in the control room that would be acceptable for eliminating the need of an STA. Until these requirements for eliminating the STA position have been established, the staff continues to require that, in addition to the staffing requirement specified in Subsection 18.1.3, an STA be available for duty on each operating shift when a plant is being operated in Modes 1-3 for a BWR. At other times, an STA is not required to be on duty.

Since the November 9, 1979 letter was issued, several efforts have been made to establish, for the longer term, the minimum level of experience, education, and training for STAs. These efforts include work on the revision to ANS-3.1, work by the Institute of Nuclear Power Operations (INPO), and internal staff efforts.

INPO has made available a document entitled "Nuclear Power Plant Shift Technical Advisor--Recommendations for Position Description, Qualifications, Education and Training." Sections 5 and 6 of the INPO document describe the education, training, and experience requirements for STAs. The NRC staff finds that the descriptions as set forth in Sections 5 and 6 of Revision O to the INPO document are an acceptable approach for the selection and training of personnel to staff the STA positions. (Note: This should not be interpreted to mean that this is an NRC requirement at this time. The intent is to refer to the INPO document as acceptable for interim guidance for a utility in planning its STA program over the long term (i.e., beyond the January 1, 1981 requirement to have STAs in place in accordance with the qualification requirements specified in the staff's November 9, 1979 letter).

Applicants for operating licenses shall provide a description of their STA training and requalification program in their application, or amendments thereto, on a schedule consistent with the NRC licensing review schedule.

Applicants for operating licenses shall provide a description of their long-term STA program, including qualification, selection criteria, training, and possible phaseout. The description shall be provided in the application, or amendments thereto, on a schedule consistent with the NRC licensing review schedule. The description shall include a comparison of the long-term program with the above-mentioned INPO document.

18.1.1.2 Interpretation

The applicant is to develop a training program in compliance with the November 9, 1979 letter and submit a description to the NRC. The applicant is to provide STA coverage for all operating shifts. Candidates will complete a training program and pass a certification examination prior to assumption of duties. The applicant is to develop a long-term program to maintain or phaseout STAs.

18.1.1.3 Statement of Response

The program for the selection and training of STAs is implemented through the appropriate Nuclear Training Procedure.

STA coverage is provided on operating shifts in accordance with Subsection 5.2.2 of the Technical Specifications. STAs perform the duties and have the responsibilities outlined in appropriate plant procedures.

STAs meet the qualification requirements of the Vassallo letter of November 9, 1979. All STA training is completed and STAs are ready for shift assignment. The STA program described above will be maintained long-term until such time as phaseout is permitted in accordance with NRC instructions.

18.1.2 Shift Supervisor Responsibilities (I.A.1.2)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.2 which contains the response to the requirement stated in NUREG-0694.

18.1.3 Shift Manning (I.A.1.3)

18.1.3.1 Statement of Requirement

Applicants for operating licenses shall include in their administrative procedures (required by license conditions) provisions governing required shift staffing and movement of key individuals about the plant. These provisions are required to assure that qualified plant personnel to man the operational shifts are readily available in the event of an abnormal or emergency situation. Interim requirements for shift staffing are given in Table 18.1-1.

These administrative procedures shall also set forth a policy, the objective of which is to prevent situations where fatigue could reduce the ability of operating personnel to keep the reactor in a safe condition. The controls established should assure that, to the extent practicable, personnel are not assigned to shift duties while in a fatigues condition that could significantly reduce their mental alertness or their decision-making ability. The controls shall apply to the plant staff who perform safety-related functions (e.g., senior reactor operators, reactor operators, auxiliary operators, health physicists, and key maintenance personnel).

IE Circular No. 80-02, "Nuclear Power Plant Staff Work Hours," dated February 1, 1980 discusses the concern of overtime work for members of the plant staff who perform safety-related functions. The guidance contained in the IE Circular No. 80-02 was amended by the July 31, 1980 letter. In turn, the overtime guidance of the July 31, 1980 letter was revised in Section I.A.1.3 of NUREG-0737. The NRC has issued a policy statement which further revises the overtime guidance as stated in NUREG-0737. This guidance is as follows:

Enough plant operating personnel should be employed to maintain adequate shift coverage without routine heavy use of overtime. The objective is to have operating personnel work a normal 8-hour day, 40-hour week while the plant is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis, the following guidelines shall be followed:

(a) An individual should not be permitted to work more than 16 hours straight (excluding shift turnover time).

(b) An individual should not be permitted to work more than 16 hours in any 24-hour period, no more than 24 hours in any 48-hour period, no more than 72 hours in any seven-day period (all excluding shift turnover time).

(c) A break of at least eight hours should be allowed between work periods (including shift turnover time).

(d) Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on shift.

Recognizing that very unusual circumstances may arise requiring deviation from the above guidelines, such deviation shall be authorized by the plant manager or his deputy, or higher levels of management. The paramount consideration in such authorization shall be that significant reductions in the effectiveness of operating personnel would be highly unlikely. Authorized deviations to the working hour guidelines shall be documented and available for NRC review. In addition, procedures are encouraged that would allow licensed operators at the controls to be periodically relieved and assigned to other duties away from the control board during their tours of duty.

Operating license applicants shall complete these administrative procedures before fuel loading.

18.1.3.2 Interpretation

None required.

18.1.3.3 Statement of Response

The facility staffing requirements are presented in Subsection 5.2.2 of the Technical Specifications. These requirements are consistent with those given in Table 18.1-1.

10 CFR Part 26, Subpart I (73 FR 16966, March 31, 2008) established new requirements for work hour limits which supersede previous requirements in TS Section 5.2.2.e.

The requirements in 10 CFR Part 26, Subpart I are implemented in SSES NDAP-QA-0025, “Working Hour Limits for Station Staff.”

18.1.4 Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications (I.A.2.1)

18.1.4.1 Statement of Requirement

Applicants* for senior operator licenses shall have 4 years of responsible power plant experience. Responsible power plant experience should be that obtained as a control room operator (fossil or nuclear) or as a power plant staff engineer involved in the day-to-day activities of the facility, commencing with the final year of construction. A maximum of 2 years power plant experience may be fulfilled by academic or related technical training, on a one-for-one time basis. Two years shall be nuclear power plant experience. At least 6 months of the nuclear power plant experience shall be at the plant for which he seeks a license. Effective date: Applications received on or after May 1, 1980.

Applicants for senior operator licenses shall have held an operator's license for 1 year. Effective date: Applications received after December 1, 1980. The NRC has not imposed the 1-year experience requirement on cold applicants for SRO licenses. Cold applicants are to work on a facility not yet in operation; their training programs are designed to supply the equivalent of the experience not available to them.

Senior operator*: Applicants shall have 3 months of shift training as an extra man on shift.

Control room operator*: Applicants shall have 3 months training on shift as an extra person in the control room. Effective date: Applications received after August 1, 1980.

Training programs shall be modified, as necessary, to provide:

1) Training in heat transfer, fluid flow and thermodynamics.

2) Training in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged.

(3) Increased emphasis on reactor and plant transients. Effective date: Present programs have been modified in response to Bulletins and Orders. Revised programs should be submitted for OLB review by August 1, 1980.

* Precritical applicants will be required to meet unique qualifications designed to accommodate the fact that their facility has not yet been in operation.

Content of the licensed operator requalification programs shall be modified to include instruction in heat transfer, fluid flow, thermodynamics, and mitigation of accidents involving a degraded core. Effective date: May 1, 1980.

The criteria for requiring a licensed individual to participate in accelerated requalification shall be modified to be consistent with the new passing grade for issuance of a license; 80% overall and 70% each category. Effective date: Concurrent with the next facility administered annual requalification examination after the issue date of this requirement.

Programs should be modified to require the control manipulations listed in Enclosure 4 of NUREG-0737, item I.A.2.1. Normal control manipulations, such as plant reactor startups, must be performed. Control manipulations during abnormal or emergency operations must be walked through with, and evaluated by, a member of the training staff at a minimum. An appropriate simulator may be used to satisfy the requirements for control manipulations. Effective date: Programs modified by August 1, 1980. Renewal applications received after November 1, 1980 must reflect compliance with the program.

Certifications completed pursuant to Sections 55.10(a)(6) and 55.33a(4) and (5) of 10 CFR Part 55 shall be signed by the highest level of corporate management for plant operation (for example, Vice President for Operations). Effective date: Applications received on or after May 1, 1980.

18.1.4.2 Interpretation

None required.

18.1.4.3 Statement of Response

A program is established to assure that all reactor operator and senior reactor operator license candidates (beyond the initial compliment required to startup Units 1 & 2) have the prescribed experience, qualifications, and training. Candidates will be prepared and certified in accordance with the appropriate Nuclear Training Procedure. Administrative procedure NDAP-QA-0300, Conduct of Operations details the process by which the qualifications of candidates for operations positions will be evaluated in the future.

The initial startup crews have completed extensive training devised in part to recognize the non-operational status of the units. This program includes real time training on the Susquehanna SES simulator which duplicates the actual unit and thus in many respects equates to the experience requirements. Subsection 13.1.3 describes the qualifications commitments for the existing plant staff.

18.1.5 Administration of Training Programs (I.A.2.3)

18.1.5.1 Statement of Requirement

Pending accreditation of training institutions, licensees and applicants for operating licenses will assure that training center and facility instructors who teach systems, integrated responses, transient, and simulator courses demonstrate senior reactor operator (SRO) qualifications and

be enrolled in appropriate requalification programs, or otherwise kept current in subjects they teach.

Training center and facility instructors who teach systems, integrated responses, transient and simulator courses shall demonstrate their competence by successful completion of a senior operator examination or certification. Effective date: Applications should be submitted no later than August 1, 1980 for individuals who do not already hold a senior operator license.

Instructors shall assure they are cognizant of current operating history, problems, and changes to procedures and administrative limitations. Effective date: Programs should be initiated May 1, 1980. Programs should be submitted to OLB for review by August 1, 1980.

18.1.5.2 Interpretation

The "instructors" referenced in this requirement are those individuals who teach systems specific to BWRs, integrated responses, transients, and simulator courses to licensed operators or license candidates.

18.1.5.3 Statement of Response

Certification of instructors is described in Nuclear Department Instruction NDI-QA-4.1.3. This procedure delineates which instructors are required to pass an examination for certification of senior reactor operators (SRO). All instructors who teach materials identified in Subsection 18.1.5.2 are certified as SROs.

18.1.6 Revise Scope And Criteria for Licensing Examinations (I.A.3.1)

18.1.6.1 Statement of Requirement

A new category shall be added to the operator written examination entitled, "Principles of Heat Transfer and Fluid Mechanics."

A new category shall be added to the senior operator written examination entitled, "Theory of Fluids and Thermodynamics."

Time limits shall be imposed for completion of the written examinations:

1. Operator: 9 hours.

2. Senior Operator: 7 hours.

The passing grade for the written examination shall be 80% overall and 70% in each category.

All applicants for senior operator licenses shall be required to be administered an operating test as well as the written examination. Effective date: Examinations administered on or after May 1, 1980.

Applicants will grant permission to NRC to inform their facility management regarding the results of the examinations for purposes of enrollment in requalification programs. Applications received on or after May 1, 1980.

Simulator examinations will be included as part of the licensing examinations.

18.1.6.2 Interpretation

None required.

18.1.6.3 Statement of Response

The reactor operator and senior reactor operator training program has been upgraded to include the subject material described in this requirement. Refer to Subsection 18.1.4.3 for the response to requirement I.A.2.1, "Immediate Upgrading of Reactor Operator and Senior Reactor Operator Training and Qualifications." Candidates will be prepared and certified in accordance with Nuclear Department Instruction NDI-QA-4.2.1. The Susquehanna SES simulator is available for the simulator portion of exams. Application packages include a release which permits the NRC to inform PP&L management of exam results.

18.1.7 Evaluation of Organization and Management (I.B.1.2)

18.1.7.1 Statement of Requirement

Each applicant for an operating license shall establish an onsite independent safety engineering group (ISEG) to perform independent reviews of plant operations.

The principal function of the ISEG is to examine plant operating characteristics, NRC issuances, Licensing Information Service advisories, and other appropriate sources of plant design and operating experience information that may indicate areas for improving plant safety. The ISEG is to perform independent review and audits of plant activities including maintenance, modifications, operational problems, and operational analysis, and aid in the establishment of programmatic requirements for plant activities. Where useful improvements can be achieved, it is expected that this group will develop and present detailed recommendations to corporate management for such things as revised procedures or equipment modifications.

Another function of the ISEG is to maintain surveillance of plant operations and maintenance activities to provide independent verification that these activities are performed correctly and that human errors are reduced as far as practicable. The ISEG will then be in a position to advise utility management on the overall quality and safety of operations. The ISEG need not perform detailed audits of plant operations and shall not be responsible for sign-off functions such that it becomes involved in the operating organization.

The new ISEG shall not replace the plant operations review committee (PORC) and the utility's independent review and audit group as specified by current staff guidelines (Standard Review Plan, Regulatory Guide 1.33, Standard Technical Specifications). Rather, it is an additional independent group of a minimum of five dedicated, full-time engineers, located onsite, but reporting offsite to a corporate official who holds a high-level, technically oriented position that is

not in the management chain for power production. The ISEG will increase the available technical expertise located onsite and will provide continuing, systematic, and independent assessment of plant activities. Integrating the shift technical advisors (STAs) into the ISEG in some way would be desirable in that it could enhance the group's contact with and knowledge of day-to-day plant operations and provide additional expertise. However, the STA on shift is necessarily a member of the operating staff and cannot be independent of it.

It is expected that the ISEG may interface with the quality assurance (QA) organization, but preferably should not be an integral part of the QA organization.

The functions of the ISEG require daily contact with the operating personnel and continued access to plant facilities and records. The ISEG review functions can, therefore, best be carried out by a group physically located onsite. However, for utilities with multiple sites, it may be possible to perform portions of the independent safety assessment function in a centralized location for all the utility's plants. In such cases, an onsite group still is required, but it may be slightly smaller than would be the case if it were performing the entire independent safety assessment function. Such cases will be reviewed on a case-by-case basis.

This requirement shall be implemented prior to issuance of an operating license.

Refer to Subsection 18.2.6 for the response to additional requirements contained in NUREG-0694.

18.1.7.2 Interpretation

None required.

18.1.7.3 Statement of Response

The functions of the Independent Safety Engineering Group (ISEG), which satisfy this requirement, are now contained in FSAR Section 17.2.1 under Manager Quality Assurance.

18.1.8 Short-Term Accident and Procedure Review (I.C.1)

18.1.8.1 Statement of Requirement

Reanalysis of small break LOCAs, transients, accidents, and inadequate core cooling and preparation of guidelines for development of emergency procedures should be completed and submitted to the NRC for review by January 1, 1981. The NRC staff will review the analyses and guidelines and determine their acceptability by July 1, 1981, and will issue guidance to licensees on preparing emergency procedures from the guidelines. Following NRC approval of the guidelines, licensees and applicants for operating licenses issued prior to January 1, 1982, should revise and implement their emergency procedures at the first refueling outage after January 1, 1982. Applicants for operating licenses issued after January 1, 1982 should implement the procedures prior to operation. This schedule supersedes the implementation schedule included in NUREG-0578, Recommendation 2.1.9 for item I.C.1(a)3, Reanalysis of Transients and Accidents. For those licensees and/or owners groups that will have difficulty in

attaining the January 1, 1981 due date for submittal of guidelines, a comprehensive program plan, proposed schedule, and a detailed justification for all delays and problems shall be submitted in lieu of the guidelines.

18.1.8.2 Interpretation

The BWR Owners' Group guidelines may be utilized to develop emergency procedures for accidents and transients.

18.1.8.3 Statement of Response

In the Clarification of the NUREG-0737 requirement "for reanalysis of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures," NUREG-0737 states:

Owners' group or vendor submittals may be referenced as appropriate to support this reanalysis. If owners' group or vendor submittals have already been forwarded to the staff for review, a brief description of the submittals and justification of their adequacy to support guideline development is all that is required.

PP&L has participated, and will continue to participate, in the BWR Owners' Group program to develop Emergency Procedure Guidelines for General Electric Boiling Water Reactors. Following are a brief description of the submittals to date, and a justification of their adequacy to support guideline development.

A. Description of Submittals

(1) NEDO-24708A, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," Revision 1, December 1980.

(a) Description and analysis of small break loss-of-coolant events, considering a range of break sizes, location, and conditions, including equipment failures and operator errors; description and justification of analysis methods.

(b) Description and analysis of loss of feedwater events, including cases involving stuck-open relief valves, and including equipment failures and operator errors; description and justification of analysis methods.

(c) Description and analysis of each FSAR Chapter 15 event resulting in a reactor system transient; demonstration of applicability of analyses to each event; demonstration of applicability of Emergency Procedure Guidelines to each event.

(d) Description of natural and forced circulation cooling; factors influencing natural circulation, including non-condensables; re-establishment of forced circulation under transient and accident conditions.

(e) Description and analysis of loss-of-coolant events, loss-of-feedwater events, and stuck-open relief valve events, including severe multiple equipment failures and operator errors which, if not mitigated, could result in conditions of inadequate core cooling.

(f) Description of indications available to the BWR operator for the detection of adequate core cooling

(g) Description and justification of analysis methods for extremely degraded cases.

(2) NEDO 24934, "BWR Emergency Procedure Guidelines BWR 1-6," Revision 1, January 1981.

Guidelines for BWR Emergency Procedures based on identification and response to plant symptoms; including a range of equipment failures and operator errors; including severe multiple equipment failures and operator errors which, if not mitigated, would result in conditions of inadequate core cooling; including conditions when core cooling status is uncertain or unknown.

B. Adequacy of Submittals

The submittals described in paragraph A have been discussed and reviewed extensively among the BWR Owners' Group, the General Electric Company, and the NRC staff. The NRC staff has found (NUREG-0737, page I.C.1-3) that "the analysis and guidelines submitted by the General Electric Company (GE) Owners' Group.comply with the requirements (of the NUREG-0737 clarification)." In Reference 18.1-1, the Director of the Division of Licensing states, "we find the Emergency Procedure Guidelines acceptable for trial implementation (on six plants with applications for operating licenses pending)."

PP&L believes that in view of these findings, no further detailed justification of the analyses or guidelines is necessary at this time. Reference 1 further states, during the course of implementation we may identify areas that require modification or further analysis and justification." The enclosure to Reference 18.1-1 identifies several such areas. PP&L will work with the BWR Owners' Group in responding to such requests.

By our commitment to work with the Owners' Group on such requests, on schedules mutually agreed to by the NRC and the Owners' Group, and by reference to the BWR Owners' Group analyses and guidelines already submitted, our response to the NUREG-0737 requirement "for reanalyses of transients and accidents and inadequate core cooling and preparation of guidelines for development of emergency procedures" by January 1, 1981, is complete.

Emergency procedures have been developed based on those guidelines.

18.1.9 Shift Relief and Turnover Procedures (I.C.2)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.8 which contains the response to the requirement in NUREG-0694.

18.1.10 Shift Supervisor Responsibility (I.C.3)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.9 which contains the response to the requirement in NUREG-0694.

18.1.11 Control Room Access (I.C.4)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.10 which contains the response to the requirement in NUREG-0694.

18.1.12 Feedback of Operating Experience (I.C.5)

18.1.12.1 Statement of Requirement

Applicants for an operating license shall prepare procedures to assure that information pertinent to plant safety originating inside or outside the utility organization is continually supplied to operators and other personnel and is incorporated into training and retraining programs. These procedures shall:

(1) Clearly identify organizational responsibilities for review of operating experience, the feedback of pertinent information to operators and other personnel, and the incorporation of such information into training and retraining programs;

(2) Identify the administrative and technical review steps necessary in translating recommendations by the operating experience assessment group into plant actions (e.g., changes to procedures, operating orders);

(3) Identify the recipients of various categories of information from operating experience (i.e., supervisory personnel, shift technical advisors, operators, maintenance personnel, health physics technicians) or otherwise provide means through which such information can be readily related to the job functions of the recipients;

(4) Provide means to assure that affected personnel become aware of and understand information of sufficient importance that should not wait for emphasis through routine training and retraining programs;

(5) Assure that plant personnel do not routinely receive extraneous and unimportant information on operating experience in such volume that it would obscure priority information or otherwise detract from overall job performance and proficiency;

(6) Provide suitable checks to assure that conflicting or contradictory information is not conveyed to operators and other personnel until resolution is reached; and,

(7) Provide periodic internal audit to assure that the feedback program functions effectively at all levels.

This requirement shall be implemented prior to issuance of an operating license.

18.1.12.2 Interpretation

None required.

18.1.12.3 Statement of Response

PP&L has established and maintains programs designed to provide operating experience feedback to operators and other personnel, and incorporate this information into training and retraining programs. Operating experience feedback is divided into two major areas; internal operating experience, and external operating experience.

Internal operating experience is programmatically addressed through the implementation of NDAP-QA-0702, Action Request and Condition Report (AR/CR) Process. The AR/CR Process provides a mechanism to document, communicate, evaluate, and address conditions and events which impact Susquehanna. NDAP-QA-0702 establishes the organizational responsibilities and communication flow paths associated with Action Requests and Condition Reports. The process identifies the programmatic steps required to take any identified condition from documentation through corrective or enhancement action. Conditions which are determined to be significant under the process are evaluated for root causes and actions to prevent recurrence. Management involvement is built into the process through the use of up-front and closure reviews. The AR/CR Process is audited periodically as part of the Corrective Action audit.

External operating experience is programmatically addressed through the implementation of NDAP-QA-0725, Operating Experience (OE) Review Program. The OE Program provides a mechanism to communicate, evaluate, and address conditions and events which may be applicable to Susquehanna. The program functions to transmit meaningful and timely information to functional groups and individuals; non-applicable information is screened out of the program by the OE Coordinator and line organization OE Advocates assigned to the major work groups. There is a wide distribution of information due to the increased awareness of the importance of evaluating ‘cross cutting issues’. Functional groups are responsible to determine the safety significance and importance of the items distributed and assigned to them, and to develop effective corrective and/or enhancement actions to preclude similar conditions from occurring at Susquehanna. The evaluations and actions are tracked to ensure effective program implementation. Training program interfaces are established under the program for applicable events. The OE Program is audited periodically as part of the Corrective Action audit.

18.1.13 Verify Correct Performance of Operating Activities (I.C.6)

18.1.13.1 Statement of Requirement

Licensees' procedures shall be reviewed and revised, as necessary, to assure that an effective system of verifying the correct performance of operating activities is provided as a means of reducing human errors and improving the quality of normal operations. This will reduce the frequency of occurrence of situations that could result in or contribute to accidents. Such a verification system may include automatic system status monitoring, human verification of operations and maintenance activities independent of the people performing the activity (see NUREG-0585, Recommendation 5), or both.

Implementation of automatic status monitoring if required will reduce the extent of human verification of operations and maintenance activities but will not eliminate the need for such verification in all instances. The procedures adopted by the licensees may consist of two phases--one before and one after installation of automatic status monitoring equipment, if required, in accordance with item I.D.3.

Procedures must be reviewed and revised prior to fuel load.

18.1.13.2 Interpretation

None required.

18.1.13.3 Statement of Response

Administrative procedure NDAP-QA-0302, "System Status and Equipment Control," provides the means to verify correct performance of surveillance and maintenance activities. Status verification utilizes control room indications presently available, operability testing where appropriate, or independent verification by a second qualified person. NDAP-QA-0027, "Station Component Verification Requirements," defines circumstances when independent human verification is required. NDAP-QA-0302 incorporates the requirements of item II.K.1.10 (see Subsection 18.2.26) for the removal from and restoration to service of safety related systems and components during normal operations and maintenance activities.

18.1.14 NSSS Vendor Review of Procedures (I.C.7)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.12 which contains the response to the requirement in NUREG-0694.

18.1.15 Pilot Monitoring of Selected Emergency Procedures for Near Term Operating Licenses (I.C.8)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.13 which contains the response to the requirement in NUREG-0694.

18.1.16 Control Room Design Review (I.D.1)

18.1.16.1 Statement of Requirement

All licensees and applicants for operating licenses will be required to conduct a detailed control-room design review to identify and correct design deficiencies. This detailed control-room design review is expected to take about a year. Therefore, the Office of Nuclear Reactor Regulation (NRR) requires that those applicants for operating licenses who are unable to complete this review prior to issuance of a license make preliminary assessments of their control rooms to identify significant human factors and instrumentation problems and establish a schedule (to be approved by NRC) for correcting deficiencies. These applicants will be required

to complete the more detailed control room reviews on the same schedule as licensees with operating plants.

Applicants will find it of value to refer to the draft document NUREG/CR-1580, "Human Engineering Guide to Control Room Evaluation," in performing the preliminary assessment. NRR will evaluate the applicants preliminary assessments including the performance by NRR of onsite review/audit. The NRR onsite review/audit will be on a schedule consistent with licensing needs.

This requirement shall be met prior to fuel load.

18.1.16.2 Interpretation

Applicants for operating licenses are required to perform a preliminary control room design assessment which should be based on NUREG/CR-1580. This assessment will be reviewed by the NRC, who will subsequently recommend changes for correcting deficiencies. Applicants must submit for NRC approval a schedule for correcting these deficiencies.

Applicants will be required to perform a detailed control room design assessment following NUREG-0700 issuance. This assessment is not required to be completed prior to issuance of an operating license.

18.1.16.3 Statement of Response

A detailed control room review to identify significant human factors problems was conducted by PP&L with assistance from experienced human factors personnel from General Physics Corporation. This review was based on the criteria given in draft NUREG/CR-1580.

During the week of October 27, 1980, the NRC performed an onsite review of the Susquehanna control room. The results of this review were formally transmitted to PP&L on January 31, 1981. A meeting was held on February 3, 1981 in Bethesda to discuss and clarify the NRC findings. On February 27, 1981 PP&L submitted a formal response to all NRC findings (refer to PLA-648). This response included a schedule for implementing the findings addressed in the NRC report.

All of these findings were addressed prior to Unit 1 fuel load or have been incorporated into the scope of the planned NUREG-700 review. All modifications that we required to be implemented prior to Unit 1 fuel load will also be implemented in Unit 2 prior to fuel load (if applicable). Also see PLA-1621 dated 4/15/83 for PPL's response to Generic Letter 82-33.

18.1.17 Plant Safety Parameter Display System (I.D.2)

18.1.17.1 Statement of Requirement

Each applicant and licensee shall install a safety parameter display system (SPDS) that will display to operating personnel a minimum set of parameters which define the safety status of the plant. This can be attained through continuous indication of direct and derived variables as necessary to assess plant safety status.

The operational date for the SPDS is October 1, 1982.

18.1.17.1.1 Function

The purpose of the safety parameter display system (SPDS) is to assist control room personnel in evaluating the safety status of the plant. The SPDS is to provide a continuous indication of plant parameters or derived variables representative of the safety status of the plant. The primary function of the SPDS is to aid the operator in the rapid detection of abnormal operating conditions. The functional criteria for the SPDS presented in this section are applicable for use only in the control room.

It is recognized that, upon the detection of an abnormal plant status, it may be desirable to provide additional information to analyze and diagnose the cause of the abnormality, execute corrective actions, and monitor plant response as secondary SPDS functions.

As an operator aid, the SPDS serves to concentrate a minimum set of plant parameters from which the plant safety status can be assessed. The grouping of parameters is based on the function of enhancing the operator's capability to assess plant status in a timely manner without surveying the entire control room. However, the assessment based on SPDS is likely to be followed by confirmatory surveys of many non-SPDS control room indicators.

Human-factors engineering shall be incorporated in the various aspects of the SPDS design to enhance the functional effectiveness of control room personnel. The design of the primary or principal display format shall be as simple as possible, consistent with the required function, and shall include pattern and coding techniques to assist the operator's memory recall for the detection and recognition of unsafe operating conditions. The human-factored concentration of these signals shall aid the operator in functionally comparing signals in the assessment of safety status.

All data for display shall be validated where practicable on a real-time basis as part of the display to control room personnel. For example, redundant sensor data may be compared, the range of a parameter may be compared to predetermined limits, or other quantitative methods may be used to compare values. When an unsuccessful validation of data occurs, the SPDS shall contain means of identifying the impacted parameter(s). Operating procedures and operator training in the use of the SPDS shall contain information and provide guidance for the resolution of unsuccessful data validation. The objective is to ensure that the SPDS presents the most current and accurate status of the plant possible and is not compromised by unidentified faulty processing or failed sensors.

The SPDS shall be in operation during normal and abnormal operating conditions. The SPDS shall be capable of displaying pertinent information during steady-state and transient conditions. The SPDS shall be capable of presenting the magnitudes and the trends of parameters or derived variables as necessary to allow rapid assessment of the current plant status by control room personnel.

The parameter trending display shall contain recent and current magnitudes of the parameter as a function of time. The derivation and presentation of parameter trending during upset conditions is a task that may be automated, thus freeing the operator to interpret the trends rather than generate them. Display of time derivatives of the parameters in lieu of trends to both optimize operator-process communication and conserve space may be acceptable.

The SPDS may be a source of information to other systems, and the functional criteria of these systems shall state the required interfaces with the SPDS. Any interface between the SPDS and a safety system shall be isolated in accordance with the safety system criteria to preserve channel independence and ensure the integrity of the safety system in the case of SPDS malfunction. Design provisions shall be included in the interfaces between the SPDS and non-safety systems to ensure the integrity of the SPDS upon failure of non-safety equipment.

A qualification program shall be established to demonstrate SPDS conformance to the functional criteria of this document.

18.1.17.1.2 Location

The SPDS shall be located in the control room with additional SPDS displays provided in the TSC and the EOF. The SPDS may be physically separated from the normal control boards; however, it shall be readily accessible and visible to the shift supervisor, control room senior reactor operator, shift technical advisor, and at least one reactor operator from the normal operating area. If the SPDS is part of the control board, it shall be easily recognizable and readable.

18.1.17.1.3 Size

The SPDS shall be of such size as to be compatible with the existing space in the control area. The SPDS display shall be readable from the emergency operating station of the control room senior reactor operator. It shall not interfere with normal movement or with full visual access to other control room operating systems and displays.

18.1.17.1.4 Staffing

The SPDS shall be of such design that no operating personnel in addition to the normal control room operating staff are required for its operation.

18.1.17.1.5 Display Considerations

The display shall be responsive to transient and accident sequences and shall be sufficient to indicate the status of the plant. For each mode of plant operation, a single primary display format designed according to acceptable human-factors principles (a limited number of parameters or derived variables and their trends in an organized display that can be readily interpreted by an operator) shall be displayed, from which plant safety status can be inferred. It is recognized that it may be desirable to have the capability to recall additional data on secondary formats or displays.

The primary display may be individual plant parameters or may be composed of a number of parameters or derived variables giving an overall system status. The basis for the selection of the minimum set of parameters in the primary display shall be documented as part of the design.

The important plant functions related to the primary display while the plant is generating power shall include, but not be limited to:

- Reactivity control
- Reactor core cooling and heat removal from primary system
- Reactor coolant system integrity
- Radioactivity control
- Containment integrity

The SPDS may consist of several display formats as appropriate to monitor and present the various parameters or derived variables. For each plant operating mode, these formats may either be automatically displayed or manually selected by the operator to keep control room operating personnel informed. Flexibility to allow for interaction by the operator is desirable in the display designs. Also, where feasible, the SPDS should include some audible notification to alert personnel of an unsafe operating condition.

The SPDS need not be limited to the previously stated functions. It may include other functions that aid operating personnel in evaluating plant status. It is desirable that the SPDS be sufficiently flexible to allow for future incorporation of advanced diagnostic concepts and evaluation techniques and systems.

18.1.17.1.6 Design Criteria

The total SPDS need not be Class 1E or meet the single-failure criterion. The sensors and signal conditioners (such as preamplifiers, isolation devices, etc.) shall be designed and qualified to meet Class 1E standards for those SPDS parameters that are also used by safety systems. Furthermore, sensors and signal conditioners for those parameters of the SPDS identical to the parameters specified within Regulatory Guide 1.97 shall be designed and qualified to the criteria stated in Regulatory Guide 1.97. For SPDS application, it is also acceptable to have Class 1E qualified devices from the sensor to a post-accident-accessible location, such as outside containment, and then non-1E devices from containment to the display (or processor) on the presumption that these components can be repaired or replaced in an accident environment. The processing and display devices of the SPDS shall be of proven high quality and reliability.

The function of the SPDS is to aid the operator in the interpretation of transients and accidents. This function shall be provided during and following all events expected to occur during the life of the plant, including earthquakes. To achieve this function, the display system shall not only take adequate account of human factors--the man-machine interface--but shall also be sufficiently durable to function during and after earthquakes. Because of current technology, it may not be possible to satisfy these criteria within one SPDS system.

From an operational viewpoint, it is preferred that only one display system be used for evaluating the safety status of the plant. One display system simplifies the man-machine interface and thus minimizes operator errors. However, in recognition of the restraints imposed

by current technology, an alternative is to design the overall SPDS function with a primary and backup display system: (1) the primary SPDS display would have high performance and flexibility and be human factored but need not be seismically qualified; and (2) the backup display system would be operable during and following earthquakes, such as the normal control room displays needed to comply with Regulatory Guide 1.97. The display system (or systems) provided for the SPDS function shall be capable of functioning during and following all design basis events for the plant.

In all cases, both the primary SPDS display and the backup SPDS seismically qualified portion of the display shall be sufficiently human factored in its design to allow the control room operations staff to perform the safety status design to allow the control room operations staff to perform the safety status assessment task in a timely manner. Dependence on poorly human-engineered Class 1E seismically qualified instruments that are scattered over the control board, rather than concentrated for rapid safety status assessment, is not acceptable for this function. An acceptable approach would be to concentrate the seismically qualified display into one segment of the control board.

The dynamic loading limitations of the SPDS design shall be defined and incorporated into the training program. The control room operations staff shall be provided with sufficient information and criteria to allow for performance of an operability evaluation of SPDS is an earthquake should occur.

The SPDS as used in the control room shall be designed to an operational unavailability goal of 0.01, as defined in Section 1.5 of NUREG-0696. The cold shutdown unavailability goal for the SPDS during the cold shutdown and refueling modes for the reactor shall be 0.2, as defined in Section 1.5 of NUREG-0696.

Technical specifications shall be established to be consistent with the unavailability design goal of the SPDS and with the compensatory measures provided during periods when the SPDS is inoperable. Operation of the plant with the SPDS out of service is allowed provided that the control board is sufficiently human factored to allow the operations staff to perform the safety status assessment task in a timely manner. Dependence on poorly human-engineered instruments that are scattered over the control board rather than concentrated for rapid safety status assessment is not acceptable for this function.

18.1.17.2 Interpretation

None required.

18.1.17.3 Statement of Response

The SPDS System is listed in Section 8 of the Emergency Pan as a part of the Plant Integrated Computer System as part of the Emergency Facilities and Equipment-Information Systems. Design details are as listed above in Section 18.1.17. Additional information is provided in our response to Generic Letter 82-33 (PLA-1621, dated 04/15/1983).

18.1.18 Training During Low-Power Testing (I.G.1)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.15 which contains the response to the requirement in NUREG-0694.

18.1.19 Reactor Coolant System Vents (II.B.1)

18.1.19.1 Statement of Requirement

Each applicant and licensee shall install reactor coolant system (RCS) and reactor pressure vessel (RPV) head high point vents remotely operated from the control room. Although the purpose of the system is to vent non-condensable gases from the RCS which may inhibit core cooling during natural circulation, the vents must not lead to an unacceptable increase in the probability of a loss-of-coolant accident (LOCA) or a challenge to containment integrity. Since these vents form a part of the reactor coolant pressure boundary, the design of the events shall conform to the requirements of Appendix A to 10 CFR Part 50, "General Design Criteria." The vent system shall be designed with sufficient redundancy that assures a low probability of inadvertent or irreversible actuation.

Each licensee shall provide the following information concerning the design and operation of the high point vent system:

(1) Submit a description of the design, location, size, and power supply for the vent system along with results of analyses for loss-of-coolant accidents initiated by a break in the vent pipe. The results of the analyses should demonstrate compliance with the acceptance criteria of 10 CFR 50.46.

(2) Submit procedures and supporting analysis for operator use of the vents that also include the information available to the operator for initiating or terminating vent usage.

Documentation shall be submitted by July 1, 1981. Modifications shall be completed by July, 1982.

18.1.19.2 Interpretation

None required.

18.1.19.3 Statement of Response

The present design of reactor coolant and reactor vessel vent systems meet these requirements.

The RPV is equipped with various means to vent the reactor during all modes of operation. All the valves involved are safety grade, powered by essential busses and are capable of remote manual operation from the control room.

The largest portion of non-condensables are vented through sixteen (16) safety relief valves (PSV 141F013A-S) mounted on the main steam lines. These power operated relief valves

satisfy the intent of the NRC position. Information regarding the design, qualification, power source of these valves has been provided in Sections 5.1, 5.2.2, 6.2, 6.3, 7.3 and 15.

In addition to power operated relief valves, the RPV is equipped with various other means of high point venting. These are:

1. Normally closed RPV head vent valves (HV141-F001 and F002), operable from control room which discharges to drywell equipment drain tank. (Subsection 5.1 and Dwgs. M-141, Sh. 1 and M-141, Sh. 2.)

2. Normally open reactor head vent line 2 DBA-112 which discharges to main steam line "A." (Subsection 5.1 and Dwgs. M-141, Sh. 1 and M-141, Sh. 2)

3. Main steam driven RCIC and HPCI system turbines, operable from the control room which exhaust to suppression pool. (Subsections 5.3 and 6.3 and Dwgs. M-149, Sh. 1 and M-155, Sh. 1)

Although the power operated relief valves fully satisfy the intent of the NRC requirement these other means also provide protection against accumulation of non-condensables in the RPV.

The design of the RCS and RPV vent systems is in agreement with the generic capabilities proposed by the BWR Owners' Group, with the exception of isolation condensers. Susquehanna SES is not equipped with isolation condensers. The BWR Owners' Group position is summarized in NEDO-24782.

Operation of the equipment described above during abnormal operating conditions is controlled by the Emergency Operating Procedures. While these procedures do not specifically address venting of non-condensable gases, they do address proper utilization of equipment to recover from undesirable conditions presented by the presence of non-condensables or by other circumstances.

The RCS and RPV vent systems are part of the original Susquehanna SES design basis. A pipe break in either of these systems would be the same as a small main steam line break. A complete main steam line break is within the design basis (see Subsections 6.2.1.1.3.3.2 and 6.3.3). Smaller size breaks have been shown to be of lesser severity (see Subsections 6.2.1.1.3.3.5 and 6.3.3.7.3). Therefore, no new supporting analysis is necessary in response to NUREG-0737. In addition, no new 10CFR50.46 conformance calculations or containment combustible gas concentration calculations are necessary. Non-condensable gas releases due to a vent line break would be no more severe than the releases associated with a main steam line break. Main steam line break analyses included continuous venting of non-condensable gases with high hydrogen concentrations. These analyses demonstrate conformance to 10CFR50.46.

18.1.20 Plant Shielding (II.B.2)

18.1.20.1 Statement of Requirement

With the assumption of a post-accident release of radioactivity equivalent to that described in Regulatory Guides 1.3 and 1.4 (i.e., the equivalent of 50% of the core radioiodine, 100% of the core noble gas inventory, and 1% of the core solids are contained in the primary coolant), each

licensee shall perform a radiation and shielding-design review of the spaces around systems that may, as a result of an accident, contain highly radioactive materials. The design review should identify the location of vital areas and equipment, such as the control room, radwaste control stations, emergency power supplies, motor control centers, and instrument areas, in which personnel occupancy may be unduly limited or safety equipment may be unduly degraded by the radiation fields during post-accident operations of these systems.

Each licensee shall provide for adequate access to vital areas and protection of safety equipment by design changes, increased permanent or temporary shielding, or post-accident procedural controls. The design review shall determine which types of corrective actions are needed for vital areas throughout the facility.

18.1.20.1.1 Documentation Required for Vital Area Access

For vital area access, operating license applicants need to provide a summary of the shielding design review, a description of the review results, and a description of the modifications made or to be made to implement the result of the review. Also to be provided by the licensee:

(1) Source terms used including time after shutdown that was assumed for source terms in systems.

(2) Systems assumed to contain high levels of activity in a post-accident situation and justification for excluding any of those given in the "Clarification" of NUREG-0737.

(3) Areas assumed vital for post-accident operations including justification for exclusion of any of those given in the "Clarification" of NUREG-0737.

(4) Projected doses to individuals for necessary occupancy times in vital areas and a dose rate map for potentially occupied areas.

18.1.20.1.2 Documentation Required for Equipment Qualification

Item II.B.2 states, "Provide the information requested by the Commission Memorandum and Order on equipment qualification (CLI-80-21)." This memorandum, with regard to equipment qualification, requests information on environmental qualification of safety related electrical equipment.

18.1.20.2 Interpretation

18.1.20.2.1 Source Terms

The source term for recirculated depressurized coolant need not be assumed to contain noble gases, therefore the RHR shutdown cooling system which may initiate at low reactor pressure only will be assumed to contain solely halogens and particulates. The HPCI and LPCI systems do not recirculate reactor coolant but, rather, suppression pool water. They will also be essentially void of noble gases.

Leakage from systems outside of containment need not be considered as potential sources. Also, containment and equipment leakage (from systems outside containment) need not be considered as potential airborne sources within the reactor building. It follows that airborne

sources and any other uncontained sources in the reactor building do not need be considered in this shielding review.

18.1.20.2.2 Post-Accident Systems

The standby gas treatment system, or equivalent, is given as a system which may contain high levels of radioactivity after an accident. Airborne activity from leakage of equipment outside containment has been clearly established as being outside the review requirements. Drywell leakage must then provide the activity processed by the SGTS. This review will assume the drywell does indeed leak to the reactor building to provide a source within the SGTS. However, this airborne source will not be evaluated any further in the review.

18.1.20.2.3 Equipment Qualification

Provide a description of the environmental qualification program and results for safety related electrical equipment both inside and outside of containment. It is our understanding that radiation qualification of non-electrical safety-related equipment need not be reported.

18.1.20.3 Statement of Response

The required post-accident study is divided into two parts; one dealing with a summary of the shielding design review plus vital area access, another dealing with equipment qualification. A summary of the shielding design review, results, and methodology used to determine radiation doses is presented below. The results of the equipment qualification program are scheduled to be submitted separately, and in compliance with commission memorandum and order CLI-80-21.

The results of the shielding review of contained sources are that all vital areas are accessible post-accident and no shielding modifications are necessary to comply to NUREG-0737.

18.1.20.3.1 Introduction

If an accident is postulated in which large amounts of activity are released from the reactor core, then pathways exist which can transfer this activity to various areas of the reactor building. These large radiation source terms present a hazard regarding potentially high doses to personnel. In order to deal with this problem it has become necessary to quantify these source terms, trace their presence and determine their effects on the efficient performance of post-accident recovery operations. To this end, the plant shielding of Units 1 and 2 has been reviewed for post-accident adequacy.

This summary presents the analytical bases by which the review was carried out. Systems required or postulated to process primary reactor coolant outside the containment during post-accident conditions were selected for evaluation. Large radiation sources beyond the original selected systems. Radiation levels in adjacent plant areas due to contained sources in piping and equipment of these systems were then estimated to yield the desired information. Also included herein is a discussion of radiation exposure guidelines for plant personnel, identification of areas vital to post-accident operations and availability of access to these areas.

As a byproduct of this review, several radiation zone maps and associated curves have been produced. The maps will allow operations personnel to identify potential high exposure vital areas of the plant should an accident occur which contaminates the system considered in this study. The curves will allow them to estimate radiation levels in these areas at various times following an accident.

18.1.20.3.2 Design Review Bases

18.1.20.3.2.1 Systems Selected for Shielding Review

A review was made to determine which systems could be required to operate and/or be expected to contain highly radioactive materials following a postulated accident where substantial core damage has occurred. The documentation governing the approach to the shielding review is NUREG-0737.

A review of containment isolation provisions was conducted in accordance with item II.E.4.2. This was done to assure isolation of non-essential systems penetrating the containment boundary. Thus, systems other than those identified as having a specified function following an accident are assumed not to contain post-accident activity and do not need to be considered in the shielding review.

18.1.20.3.2.1.1 Core Spray, HPCI, RCIC and RHR (LPCI mode)

The Core Spray, RHR (LPCI mode), HPCI (water side) and RCIC (water side) systems would contain suppression pool water being injected into the reactor coolant system. Although the HPCI and RCIC systems could also draw from the condensate storage tank, suppression pool water is assumed to be their only source of water for injection. The steam sides of the HPCI and RCIC systems would operate on reactor steam and would not be required when the reactor is depressurized. However, as a first estimate for equipment qualification, it is assumed that these systems should also be available until one year post-accident.

18.1.20.3.2.1.2 RHR (Shutdown Cooling Mode)

The RHR system recirculates reactor waste heat when it operates in the shutdown cooling mode. Operation in this mode requires that the reactor be in depressurized condition. Depressurization is expected to remove substantially all of the noble gases released into the reactor coolant whether it be by direct venting to the drywell or by quenching reactor steam in the suppression pool. Another consideration is, following a postulated serious accident, the HPCI, RCIC, RHR (LPCI Mode) and/or Core Spray systems would inject a substantial amount of water into the reactor coolant system. This shielding review will assume that there are no noble gases in the reactor water in the RHR system from the shutdown cooling mode. However, since the exact amount of dilution of the reactor water is difficult to determine, no dilution in addition to the reactor coolant volume is assumed.

18.1.20.3.2.1.3 RHR (Suppression Pool Cooling Mode)

The RHR system in this mode circulates and removes heat from suppression pool water to prevent pool boiling. This assures availability of suppression pool water as a source for cooling the reactor and increases the efficiency of a given cooling operation with this source.

18.1.20.3.2.1.4 RHR (Containment Spray Mode)

Under post-accident conditions, water pumped from the suppression pool through the RHR heat exchanger may be diverted to spray header system loops located high in the drywell and above the suppression pool. This mode of operation provides the ability to reduce containment pressure by condensing atmospheric steam while cooling the suppression pool water. No credit is taken for spray removal of iodines.

18.1.20.3.2.1.5 CRD Hydraulic System

The operation of the CRD system was reviewed to determine if the scram discharge headers will contain highly radioactive water following a postulated accident. Prior to a scram the CRD housings contain condensate water delivered by the CRD pumps. When a scram occurs some of this condensate water from the CRD system is discharged to the scram discharge header. After the scram, some condensate and reactor water flows to the scram discharge header which fills in a matter of a few seconds.

Since the vents and drains in the scram discharge headers are isolated by the scram, all discharge flow then stops. Since it is not reasonable to assume that significant core damage occurs in the first few seconds following a scram, the scram discharge header will initially contain only a mixture of condensate and pre-accident reactor water following this postulated accident. After the reactor scram, the scram discharge and instrument volumes will contain about 700 gallons of pre-accident water, isolated by a single drain valve leak tested to 20 cc/hr. If the initial scram closed the drain valve, then this leakage is insignificant compared to the scram discharge volume and insignificant as a post-accident concern. If the drain valve fails to close, operator action is required to reset the scram and close the soft-seated scram discharge valve. If this action is not taken or fails to close the valve, then post-accident sources can enter the liquid radwaste system by leaking past the CRD seals. The CRD withdraw line does not directly communicate with the reactor coolant.

In light of the anticipated small leak rates and the lack of single failure criteria consideration requirements, the scram discharge drain valve was assumed to remain closed and any leakage was disregarded.

18.1.20.3.2.1.6 RWCU System

For a major accident with resulting core damage, the RWCU system would automatically isolate on a low reactor coolant level signal and would contain no highly radioactive materials beyond the second isolation valve. Since the cleaning capacity for this system is small, it would be impractical to use it for TMI type accident recovery and it is excluded from this shielding review.

18.1.20.3.2.1.7 Liquid Radwaste System

Equipment drains and compartment floor drains servicing ECCS systems are isolated from the reactor building sump. All piping that may contain high activity post-accident water is also isolated from the reactor building sump and radwaste systems. CRD system isolation is discussed in Subsection 18.1.20.3.2.1.5. Since no significant amounts of post-accident activity can reach the liquid radwaste system, it is excluded from this shielding review.

18.1.20.3.2.1.8 This Section Is Not Used

18.1.20.3.2.1.9 Sampling Systems

Sampling systems required or desired for post-accident use include the Containment Atmosphere Monitoring System, the Plant Vent Sampling System PVSS and the Post-Accident Vent Sampling System PAVSS. Each of these systems/stations may contain post-accident sources and is included in the shielding review.

18.1.20.3.2.1.10 Standby Gas Treatment System

The Reactor Building Recirculation system is used after an accident. This disperses airborne activity throughout the reactor building and refueling floor. The SGTS system collects airborne activity, concentrating halogens within the charcoal filters while releasing noble gases outside the secondary containment. The charcoal filter is considered to be a source of contained activity and is included in this shielding review. The assumptions used in determining this contained source are:

1) Drywell leakage at 1% per day.

2) SGTS process rate of 1.4 reactor building/refueling floor volume per day.

3) 99% charcoal filter efficiency for halogens. 0% charcoal filter efficiency for noble gases.

18.1.20.3.2.1.11 Containment Atmosphere (Drywell)

The free volume of the primary containment is assumed to initially contain large amounts of post-accident activity, namely core noble gases, halogens and particulates. Shine through the drywell wall was examined to determine the effects on reactor building radiation levels. Results indicate the six-foot thick drywell shield wall reduces shine to radiation Zone I levels. Shine through penetrations presents no additional hazard because piping is directed to penetration rooms where area dose rates will be dominated by internal piping.

18.1.20.3.2.1.12 Suppression Pool (Wetwell)

The suppression pool is assumed to initially contain post accident core halogens and particulate activity. Shine through the wetwell wall was examined to determine the effects on radiation

levels in the reactor building. It was determined that the six foot thick wetwall shield wall reduces wetwell shine to radiation Zone I levels in the reactor building.

18.1.20.3.2.2 Radioactive Source Release Fractions

The following release fractions were used as a basis for determining the concentrations for the shielding review:

Source A: Containment Atmosphere: 100% noble gases, 30% halogens; 25% alkali metals; 5% tellurium metals; 2% barium, strontium; 0.25% noble metals; 0.05% cerium group; 0.02% lanthanides.

Source B: Reactor Liquids: 100% noble gases, 30% halogens, 25% alkali metals; 5% tellurium metals; 2% barium, strontium; 0.25% noble metals; 0.05% cerium group 0.02% lanthanides.

Source C: Suppression Pool Liquid: 30% halogens, 25% alkali metals; 5% tellurium metals; 2% barium, strontium; 0.25% noble metals; 0.05% cerium group; 0.02% lanthanides.

Source D: Reactor Steam: 100% noble gases, 30% halogens

The above release fractions are based on Regulatory Guide 1.183, Table 1 and implementation Alternative Source Term (AST) methodology. The above release fractions were applied by radionuclide group (I.e. noble gas iodine, etc.) to the equilibrium fission product inventory for Susquehanna listed in Table 18.1-2 to obtain the total curies for each post-accident source. Radionuclide groups are identified in Regulatory Guide 1.183 Table 5 and are as follows:

Radionuclide Groups

Group	**Elements**
Noble Gases	Xe, Kr
Halogens	I, Br
Alkali Metals	Cs, Rb
Tellurium Group	Te, Sb, Se, Ba, Sr
Noble Metals	Ru, Rh, Pd, Mo, Tc, Co
Lanthananides	La, Zr, Nd, Eu, Nb, Pm, Pr Sm, Y, Cm, Am
Cerium	Ce, Pu, Np

18.1.20.3.2.3 Source Term Quantification

Subsection 18.1.20.3.2.2 above outlines the assumptions used for release fractions for the shielding design review. These release fractions are, however, only the first step in modeling the source terms for the activity concentrations in the systems under review. The important modeling parameters, decay time and dilution volume obviously also affect any shielding analysis. The following sections outline the rationale for the selection of values for these key parameters.

18.1.20.3.2.3.1 Decay Time

Post-accident radiation sources used for the shielding review and for vital area access are based on Alternative Source Terms (AST) releases per regulatory Guide 1.183 releases as identified in Section 18.1.20.3.2.2. Maximum AST post-accident does rates are used for both the shielding review and for vital area doses which for AST occurs two hours post-accident.

18.1.20.3.2.3.2 Dilution Volume

The volume used for dilution is important, affecting the calculations of dose rate in a linear fashion. The following dilution volumes were used with the release fractions and decay times listed above to arrive at the final source terms for the shielding review:

Source A: Drywell and suppression pool free volumes.

Source B: Reactor coolant system normal liquid volume (based on reactor coolant density at the operating temperature and pressure).

Source C: The volume of the reactor coolant system plus the suppression pool volume.

Source D: The reactor steam volume.

18.1.20.3.2.4 System/Source Summary

- Core Spray System: Source C

- High Pressure Coolant Injection System

  Liquid: Source C
  Steam: Source D (with credit for steam specific activity reduction due to turbine operation)

- Reactor Core Isolation Cooling System

  Liquid: Source C
  Steam: Source D (with credit for steam specific activity reduction due to turbine operation).

- Residual Heat Removal System

  LPCI Mode: Source C

  Shutdown Cooling Mode: Source B (with credit for noble gas release during vessel depressurization).

  Suppression Pool Cooling and Containment Spray

  Modes: Source C

•	Sampling Systems Containment air sample:	 Source A
	Reactor coolant sample:	Source B
	Plant vent sample:	1% per day Drywell leakage following the filtration by the Standby Gas Treatment System (see Subsection 18.1.20.3.2.1.10 for discussion of SGTS source assumptions).
•	Standby Gas Treatment System	
	Charcoal filter:	1% per day drywell leakage (see Subsection 18.1.20.3.2.1.10 for discussion of source assumptions).
•	Drywell:	Source A
•	Wetwell:	Source C
•	Instrument Lines Penetrating Containment	Source A Source B Source C
•	Steam Drain Lines Associated with ICTM (Isolated Condenser Treatment Method)	 Source D

For each of these systems, piping associated with the appropriate operating mode was identified on piping and instrumentation drawings and traced throughout the plant to their final destination.

18.1.20.3.2.5 Dose Integration Factors for Personnel

Cumulative radiation exposure to personnel in vital areas (continuous occupancy) is determined based upon a maximum one-year exposure period. The integrated doses are modified using Reference 18.1-8 occupancy factors listed below.

Time (days)	Occupancy Factors
0 to 1	1.0
1 to 4	0.6
over 4	0.4

Exposures for areas not continuously occupied (frequent and infrequent occupancy) must be determined case by case, that is, multiply the task duration by the area dose rate at the time of exposure.

18.1.20.3.3 Shielding Review Methodology

18.1.20.3.3.1 Radiation Dose Calculation Model

The previous sections outlined the rationale and assumptions for the selection of systems that would undergo a shielding design review as well as the formulation of the sources for those systems. The next step in the review process was to use those sources along with standard point kernel shielding analytical techniques (Ref. 18.1-14 and 18.1-15) to estimate dose rates from those selected systems.

Scattered radiation (e.g., shine over partial shield walls) was considered but was not significant since the net reduction in dose is several orders of magnitude and no vital area is separated from a high activity source solely by a partial wall.

Radiation levels for compartments containing the systems under review were based on the maximum contact dose rate for any component in the compartment. Radiation levels in areas not containing unshielded sources were based on maximum dose rates transmitted into areas through walls of these adjacent compartments. Checks were also made for any piping or equipment that could directly contribute to corridor dose rates, i.e., piping that may be running directly in the corridor or equipment/piping in a compartment that could shine directly into corridors with no attenuation through compartment walls. There is no field routed small piping (i.e., piping less than 2" in diameter) for ECCS systems.

Dose rates are cumulative and are summed over all systems in simultaneous operation in most cases. The exception is steam piping for the RCIC and HPCI systems. Both are high pressure systems and cannot be operated simultaneously with low pressure systems such as core spray. This becomes a moot point, since these steam lines are routed in well shielded compartments, causing no appreciable personnel doses.

18.1.20.3.3.2 Post-Accident Radiation Zone Maps

One of the principal products of this review is the series of accident radiation zone maps (Figures 18.1-2 to 8). The zone boundaries used in the maps are defined in Table 18.1-3. The zone maps present the calculated dose rates at two hours after the accident due to the sources described in Subsection 18.1.20.3.2.4 in various areas of the plant site. This time was selected to correspond to the maximum post LOCA activity release occurring at two hours. The principal sources of radiation in each area are identified in Table 18.1-5.

The dose rates presented do not include contributions from normal operating sources which may be contained in the plant at the time of the accident since these contributions will be minor outside of well defined and shielded areas. They also do not include dose rate contributions due to potential airborne sources resulting from equipment or drywell leakage.

The zone maps were used to determine the accessibility of vital areas described in Subsection 18.1.20.3.3.4.

18.1.20.3.3.3 Personnel Radiation Exposure Guidelines

In order that doses to occupied areas take on meaningful proportions, it is necessary to establish exposure goals or guidelines. The general design basis for these guidelines is 10CFR50, Appendix A, GDC 19. That material addresses control room habitability, including access and occupancy under worst case conditions. Exposures are not to exceed 5 rem total effective dose (TEDE) equivalent to any for the duration of any postulated accident. GDC 19 is also used to govern design bases for the maximum permissible dosage to personnel performing any task required post-accident. These requirements translate roughly into the objectives to be met in the post-accident review as given below.

Radiation Exposure Guidelines		
Occupancy	Dose Rate Objectives	Dose Objective
Continuous	15 mR/hr	5 Rem for duration
Frequent	100 mR/hr	5 Rem for all activities
Infrequent	500 mR/hr	5 Rem per activity
Accessway	5 R/hr	Included in above doses

18.1.20.3.3.4 Vital Area Identification and Access

18.1.20.3.3.4.1 Vital Area Clarification

Vital areas are those "which will or may require occupancy to permit an operator to aid in the mitigation of or recovery from an accident." Reference (18.1-16) further defines recovery from an accident as, "when the plant is in a safe and stable condition." "This may either be hot or cold shutdown, depending on the situation." The 10 CFR 73.2 definition of vital area shall not apply here.

For the purposes of this study, the evaluation to determine necessary vital areas considers all of those listed in Reference (18.1-3). Upon examination several plant areas were determined not to be vital. Instrument panels were excluded because essential equipment control and alignment has been established in the control room and requires no local actions. The radwaste control room is excluded because 1) no local actions are required to prevent spread of post-accident sources into the liquid radwaste system; 2) gaseous radwaste processing is not required, and; 3) activity sources early in the post-accident transient are much too high to be effectively processed through the liquid and eventually solid radwaste systems. Also excluded are the post-LOCA hydrogen control system and the containment isolation reset control area (which are operator actuated from the main control room). Lastly the emergency power supply (i.e., diesel generators) was excluded since system initiation comes from the control room and requires no local actions.

The resulting list of areas considered vital for post-accident operations at Susquehanna appears in Table 18.1-4. Note that security facilities are included as vital areas with regards to maintaining plant security. Note that the EOF is excluded as it is outside the 10-mile EPZ.

18.1.20.3.3.4.2 Vital Area Access

Those operator actions required post-accident were reviewed to assure that first priority safety actions can be achieved in the postulated radiation fields. This review assures that access is available and required operator actions can be achieved.

Ingress and egress area dose rates to those vital areas identified in Table 18.1-4 were examined to ensure compatibility with the areas being accessed.

All vital area access doses are based upon Alternative Source Term (AST) methodology and contained sources at 2 hours post LOCA.

The Radiation Chemistry Laboratory (RCL) is located on elevation 676’ of the control structure. The dose for a mission to the laboratory is for a 30 minute occupancy.

Sampling and analysis of post accident plant effluents are performed at the Post Accident Vent Sample Station (PAVSS) located on elevation 729’ of the turbine building.

Two separate operator access missions may be required to provide emergency service water (ESW) makeup to the spent fuel pool under LOCA conditions. In Unit 1, one mission is to elevation 749’ of the reactor building to control ESW makeup flow. The second mission for Unit 1 is to elevation 670’ of the reactor building to align the ESW system to the spent fuel pool and is the most limiting mission for vital area access doses. In Unit 2, the ESW system tie-in mission is performed on Elevation 683’ and the flow control mission to Elevation 749’ similar to Unit 1.

For Unit 1 two separate operator access missions may be required to provide emergency service water (ESW) makeup to the spent fuel pool under LOCA conditions. One mission is to Elevation 749’ of the reactor building to control ESW System makeup flow. The second mission is to Elevation 670’ of the reactor building to align the ESW system to the spent fuel pool which is the most limiting mission. In Unit 2, the ESW system tie-in mission is performed on Elevation 683’ and the flow control mission to Elevation 749’ similar to Unit 1.

18.1.20.3.4 Results

18.1.20.3.4.1 Post Accident Radiation Levels

Results of the radiation level evaluation for the shielding design review are presented in Figures 18.1-1 to 8. Table 18.1-5 identifies the sources contributing to dose rates in each of the plant areas shown on those figures.

18.1.20.3.4.2 Integrated Personnel Exposures

Table 18.1-4 provides the total integrated does to personnel in continuously occupied vital areas. The estimated doses are based on exposure to AST post LOCA contained radiation sources for the duration of the accident for areas inside the control structure and for one year occupancy at other site locations. Results show that personnel exposures are within the design objective of 5 REM TEDE.

The exposure to personnel located in non-continuously occupied vital areas or in the performance of a vital mission are also within the GDC 19 dose objective of 5 Rem TEDE. The integrated doses provided in Table 18.1-4 for the Radiation Chemistry Laboratory (RCL) and sample stations includes only the dose from contained post accident radiation sources (i.e. sample system piping and other contained piping sources) and does not include the dose from the samples themselves. The samples are locally shielded and present no access problems in the area of the stations. Personnel mission doses are calculated based on an estimated task duration at specified times post accident for a one person task force.

Completion of the emergency service water flow control mission for Units 1 and 2 are estimated at less than 1 Rem. The Unit 1 emergency service water tie-in to the spent fuel pool mission dose is estimated at 3.6 Rem with the Unit 2 mission estimated at less than 1 Rem.

18.1.20.3.4.3 Reactor Building Accessibility

The results show that the reactor building will be generally inaccessible for several days after the accident due to contained radiation sources. High radiation levels can be expected at Elevation 645'-0" (Figure 18.1-3) regardless of which system(s) is (are) in operation. Radiation levels at Elevation 719'-0" (Figure 18.1-5) and above are expected to generally be within Zone IV limits if the core spray and RHR containment spray systems have not been operated following the accident. This is because these are the only unshielded post-accident system sources at these elevations. Other system sources are contained in shielded cubicles.

Results for contained radiation sources show that the vital area in the Reactor Building is accessible post-accident.

18.1.20.3.4.4 Control Building Accessibility

Results for contained radiation sources show that vital areas in the control structure are accessible post-accident.

18.1.21 Post-Accident Sampling (II.B.3)

18.1.21.1 Statement of Commitment

PPL Susquehanna has made the following commitments to the NRC in conjunction with NRC approval to eliminate the Post Accident Sampling System requirements from the Technical Specifications:

1. Contingency plans for obtaining and analyzing highly radioactive samples from the reactor coolant system, suppression pool, and containment atmosphere shall be maintained.
2. A capability for classifying fuel damage events at the Alert Level threshold (typically this 300 uCi/ml dose equivalent iodine) shall be maintained. This capability may use a normal sampling system or correlations of radiation readings to coolant concentrations.

3. An I-131 site survey detection capability, including an ability to assess radioactive iodines released to offsite environs, by using effluent monitoring systems or portable sampling equipment shall be maintained.

The Post-Accident Sampling System equipment and other plant sampling processes may be utilized to meet these commitments.

18.1.21.2.1 Introduction

The Post-Accident Sampling System (PASS) concept is based upon obtaining grab samples for remote laboratory analysis, having a minimum of operating complexities, having very little "in-line" instrumentation, having modular construction for maintenance and contamination control purposes, and being compact in size so as to require less shielding and to better fit into existing plants. This concept results in a three-step sampling/analysis process. The samples are obtained via a Post Accident Sample Station located adjacent to secondary containment. They are then transported to a sample preparation area which consists of a wet chemistry laboratory with the capability to perform chemical analyses as well as prepare the samples for radioisotopic analysis. The final step involves transporting the samples to a counting area with a sufficiently low background to permit accurate gamma-ray spectroscopic analysis.

18.1.21.2 1 System Description

The underlying philosophy in the design of the sampling system is to minimize exposure by minimizing the required sample sizes, to optimize the weight of the shielded sample containers in order to facilitate movement through potentially high-level radiation areas, and to provide adequate shielding at the sample station.

18.1.21.2.2 Sample Points

a) Wetwell and Drywell Atmosphere

Gas samples can be obtained from two separate areas in both the drywell and wetwell. The sample lines tap into the containment air monitoring system sample lines outside of primary containment and after the second containment isolation valve. The two drywell sample taps are on the highpoint line, sampling at elevation 790', and the midpoint line, sampling at elevation 750'.

b) Secondary Containment Atmosphere

A sample line was installed to allow sampling of the secondary containment atmosphere.

c) Reactor Coolant and Suppression Pool Liquid Samples.

When the reactor is pressurized reactor coolant samples can be obtained from a tap off the jet pump pressure instrument system. The sample point is on a non-calibrated jet pump instrument line outside of primary containment and after the excess flow check valve.

A single sample line is also connected to both loops in the RHR system. The sample lines tap off the high pressure switch instrument lines coming off the common section of the RHR system return line. This sample point provides a means of obtaining a reactor coolant sample when the reactor is not pressurized and at least one of the RHR loops is operated in the shutdown cooling mode. Similarly, a suppression pool sample can be obtained from an RHR loop lined up in the suppression pool cooling mode.

18.1.21.2.3 Isolation Valves and Sample Lines

Containment isolation for the drywell and wetwell gas sample lines is provided by the existing H_2O_2 Analyzer supply and return line primary containment isolation valves and closed system boundary valves. The primary containment isolation valves and the associated closed system boundary valves are identified in Table 6.2-22 and note 31 to this table. The jet pump instrument sample line containment isolation is provided by an existing isolation valve and excess flow check valve upstream of the sample tap. All gas sample lines from the sample taps to and including the first flow control valves are seismic category 1 except for the secondary containment sample line which has no control valve before it enters the sample panel. The sample lines from the RHR system are seismic category 1 through both system isolation valves and a flow restricting orifice. The sample line from the jet pump instrument system is seismic category 1 to the flow control/isolation valve. All containment isolation valves upstream of the sample taps can be overridden from the control room. All isolation and control valves shown in Dwg. M-123, Sh. 5 which are within the Q boundary are controlled by a single permissive switch in the control room and individually controlled at the sampling control panel located adjacent to the sample station.

The solenoid isolation and control valves which are part of the post accident sample system to the Q boundary will be environmentally qualified.

18.1.21.2.4 Piping Station

The piping station, which is installed within the reactor building, includes sample coolers and control valves which determine the liquid sample flow path to the sample station. The location for the piping station is shown in Dwg. M-243, Sh. 1. Cooling water comes from the Reactor Building Closed Cooling Water System.

18.1.21.3.2.4 Sample Station and Control Panels

The location of the sample station, control panels and associated equipment is shown in Dwg. M-223, Sh. 1. The sample station consists of a wall mounted frame and enclosures. Included within the sample station are equipment trays which contain modularized liquid and gas samplers. The lower liquid sample portion of the sample station is shielded with 6 inches of lead brick, whereas the upper gas sampler has 2 inches of lead shielding. The control instrumentation is installed in two control panels. One of these panels contains the conductivity, and radiation level readouts. The other control panel contains the flow, pressure, and temperature indicators, and various control valves and switches. The various sample lines and return lines enter the sample station enclosure (which is mounted flush against the secondary containment wall) through the back by way of a penetration in the steam tunnel wall.

18.1.21.2.5.1 Gas Sampler

The gas sample system is designed to operate at pressure ranging from sub-atmospheric to the design pressures of the primary containment one hour after a loss-of-coolant accident. The gas sample is chilled to remove moisture, and a 15 milliliter grab sample can be taken for determination of gaseous activity and for gas composition by gas chromatography. Additionally, there is a particulate and iodine sampling loop with a radiation monitor; however, this loop will not be maintained. The gas is collected in an evacuated vial using hypodermic needles in a manner analogous to the normal off-gas samples. When purging the drywell and wetwell gas sample lines to obtain a representative sample, the flow is returned to the wetwell; however, during purging of the secondary containment line and when flushing the sample panel lines with air or nitrogen, flow is returned to secondary containment. The sample station design allows for flushing of the entire sample panel line from the four position selector value through the needles with either air, nitrogen, or the gas to be sampled. This capability will minimize any possible cross contamination between the various samples.

18.1.21.2.5.2 Liquid Sampler

The liquid sample system is designed to operate at pressures from 0 to 1500 psi. The design purge flow of 1 gpm is sufficient to maintain turbulent flow in the sample line and serves to alleviate cross contamination between samples. The purge flow is returned to the suppression pool. The liquid sampling system is designed to allow routine demineralized water flushing of the system lines from a point between the two coolers in the piping station through the sampling needles. Using the hydro-test connection which is outside the sample panel, it is also possible to backflush all the liquid sample lines through the sample tap point. This will allow for clearing of plugged lines. All liquid samples are taken into 15 milliliter septum bottles mounted on sampling needles. In the normal lineup, the sample flows through a ball valve bored out to 0.10 milliliter volume. After flow through the sample panel is established, the ball valve is rotated 90° and a syringe filled with air or water, connected to a line external to the panel, is used to flush the sample plus a measured volume of diluent through the valve and into the sample bottle. The sample bottle is contained in a shielded cask and remotely positioned on the sample needles through an opening in the bottom of the sample enclosure. Alternately, A ten milliliter aliquots of liquid can be taken for analysis using a large volume cask and cask positioner through needles on the underside of the sample station enclosure.

18.1.21.2.5.3 Sample Station Ventilation

The sample station enclosure is vented to secondary containment via the main steam line tunnel. Ventilation is motivated by differential pressure between the turbine and reactor buildings. The ventilation rate required for heat removal during operation is about 40 scfm. The ventilation duct is sized for less than 100 scfm at 1/4 inch of water differential pressure when the enclosure is opened for maintenance. Standby air flow will be about 3 scfm and can be reduced by taping all openings. A pressure gauge is attached to the sample station enclosure to monitor the pressure differential between the enclosure and the general sampling area in the turbine building. This will assure the operator that airborne activity in the sample enclosure will be swept into secondary containment.

18.1.21.2.5.4 Sample Station Sump

The sample station is provided with a sump at the bottom of the sample enclosure which will collect any leakage within the enclosure. This sump can be isolated and pressurized, discharging into the suppression pool.

18.1.21.2.5.5 Sample Handling Tools and Transport Containers

Appropriate sample handling tools and transporting casks are provided. Gas vials are installed and removed by use of a vial positioner through the front of the gas sampler. The vial is then manually dropped into a small shielded cask directly from the positioning tool. This allows the operator to maintain a distance of about three feet from the unshielded vial. This cask provides about 1-1/8 inches of lead shielding. A 1/8-inch diameter hole is drilled in the cask so that an aliquot can be withdrawn from the vial with a gas syringe without exposing the analyst to the unshielded vial.

The small volume liquid sample cask is a cylinder with a lead wall thickness of about two inches. The cask weighs approximately 65 pounds and has a handle which allows it to be carried by one person. The 10 milliliter sample is taken in a 700-pound lead shielded cask which is transported and positioned by a four-wheel dolly. The sample is shielded by about 5-1/2 inches of lead.

18.1.21.2.5.6 Sample Station Power Supply

The PASS isolation and control valves, sample station control panels, and auxiliary equipment, are connected to an Instrument AC Distribution Panel which is powered from an Engineered Safeguard System (ESS) bus. Following a loss of off-site power, the ESS bus is powered from the on-site diesel generators. The Reactor Building Closed Cooling Water System, which is needed for the sample coolers, is also powered from the emergency diesel generators following a loss of off-site power. Compressed nitrogen for the air-operated valves comes from compressed nitrogen cylinders, thus eliminating any dependence on the plant compressed air system.

18.1.21.2.6. Description of Sample Preparation/Chemistry and Nuclear Counting Facilities

After the samples are obtained from the sample station, they will be transported to the on-site Chemistry laboratory for chemical and radioisotopic analyses.

The plant shielding study results, presented in Subsection 18.1.20.3, show that following an accident, the chemistry laboratory will be a Zone II area ($\leq$ 100 mR/h). Therefore, the existing facilities will be accessible at least for intermittent use following an accident. The most direct route between the sample station and these facilities is through areas of the turbine building which should be Zone I areas ($\leq$ 15 mR/h) following an accident.

If a problem is encountered with the on-site Chemistry count room, such as high background radiation levels, backup high resolution gamma-ray spectromenter systems are available in the on-site Health Physics count room and at designated off-site facilities.

18.1.21.2.7. Summary Description of Procedures

Procedures are maintained for the following activities:

(1) Sample collection and transportation.

(2) Obtaining gas samples from primary containment and suppression pool.

(3) Obtaining liquid samples of primary coolant and suppression pool.

18.1.21.2.71 Chemical/Radiochemical Procedures

18.1.21.2.7.1.1 Introduction

The PASS provides a means of obtaining primary coolant, suppression pool, and primary containment air samples. Because of the extremely high radioactivity levels associated with extensive fuel damage, the PASS and its associated analysis procedures were developed with the philosophy of providing the capability of obtaining the necessary samples and of performing analyses while minimizing does.

18.1.21.2.7.1.2 Sample Preparation

Liquid samples will be taken at the sample station in septum type bottles and transported to the analysis facility in shielded containers. Sample aliquots are then taken from the septum bottles for analysis or further dilution using standard laboratory procedures.

Gas samples are taken at the sample station in a 14.7 ml septum bottle. A shielded carrier is furnished for the 14.7 ml serum bottle with a small hole at the septum end so that a gas sample can be withdrawn from the carrier using a hypodermic syringe without having to handle the bottle.

18.1.21.2.7.2 System Testing and Operator Training

Testing of the PASS approximately once every two years on each unit assures operability of the system. Samples are taken from the primary containment atmosphere, the reactor coolant and the suppression pool. The functional testing also serves to maintain operator proficiency.

18.1.22 Training for Mitigating Core Damage (II.B.4)

18.1.22.1 Statement of Requirement

Licensees are required to develop and implement a training program to teach the use of installed equipment and systems to control or mitigate accidents in which the core is severely damaged.

Shift technical advisors and operating personnel from the plant manager through the operations chain to the licensed operators shall receive all the training indicated in Table 18.1-8.

Managers and technicians in the instrumentation and control, health physics, and chemistry departments shall receive training commensurate with their responsibilities.

Applicants for operating licenses should develop a training program prior to fuel loading and complete personnel training prior to full-power operation.

18.1.22.2 Interpretation

None required.

18.1.22.3 Statement of Response

A course titled "Mitigating Core Damage" has been developed and is available to all shift technical advisors and operations personnel from the plant manager through the operations chain to and including licensed operators to fulfill this training requirement. A course outline is provided in Table 18.1-9.

Managers and technicians in instrumentation and controls, health physics, and chemistry are given training commensurate with their responsibilities during accidents which involve severe core damage.

18.1.23 Relief and Safety Valve Test Requirements (II.D.1)

18.1.23.1 Statement of Requirement

Boiling-water reactor licensees and applicants shall conduct testing to qualify the reactor coolant system relief and safety valves under expected operating conditions for design-basis transients and accidents.

Licensees and applicants shall determine the expected valve operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Revision 2. The single failures applied to these analyses shall be chosen so that the dynamic forces on the safety and relief valves are maximized. Test pressures shall be the highest predicted by conventional safety analysis procedures. Reactor coolant system relief and safety valve qualification shall include qualification of associated control circuitry, piping, and supports, as well as the valves themselves.

Pre-implementation review will be based on EPRI, BWR, and applicant submittals with regard to the various test programs. These submittals should be made on a timely basis as noted below, to allow for adequate review and to ensure that the following valve qualification date can be met:

Final BWR Test Program--October 1, 1980

Post-implementation review will be based on the applicants' plant-specific submittals for qualification of safety relief valves. To properly evaluate these plant-specific applications, the test data and results of the various programs will also be required by the following dates:

BWR Generic Test Program Results -- July 1, 1981

Plant-specific submittals confirming adequacy of safety and relief valves based on licensee/applicant preliminary review of generic test program results – July 1, 1981

Plant-specific reports for safety and relief valve qualification -- October 1, 1981

Plant-specific submittals for piping and support evaluations – January 1, 1982.

18.1.23.2 Interpretation

None required.

18.1.23.3 Statement of Response

PP&L is participating in the BWR Owner's Group (BWROG) program to test safety/relief valves (SRVs). Wyle Laboratories in Huntsville, Alabama has been contracted to design and build a test facility. The design is complete and construction is well underway. The facility will be capable of high and low pressure valve tests.

Documentation of the BWROG testing program was sent to the NRC on September 17, 1980 by a letter from D.B. Waters to R.N. Vollmer. A summary of this document is provided below.

An engineering evaluation was done to identify the expected operating conditions for SRVs during design basis transients and accidents. This evaluation indicates the SRVs may be required to pass low pressure liquid as a result of the Alternate Shutdown Mode (described in Subsection 15.2.9). No other significantly probable event, even combined with a single active failure or single operator error, produces expected operating conditions that justify qualification of SRVs for extreme operating conditions. Therefore a test program was developed to demonstrate the SRVs' capabilities as may be necessary during the Alternate Shutdown Mode.

The test results were submitted by a letter to A. Schwencer from N. W. Curtis on July 1, 1981 (PLA-865). A plant specific SRV qualification report was submitted to the NRC on October 1, 1981 (PLA-940). This report includes all necessary evaluations of piping and supports.

18.1.24 Safety/Relief Valve Position Indication (II.D.3)

18.1.24.1 Statement of Requirement

Reactor coolant system relief and safety valves shall be provided with a positive indication in the control room derived from a reliable valve-position detection device or a reliable indication of flow in the discharge pipe.

The basic requirement is to provide the operator with unambiguous indication of valve position (open or closed) so that appropriate operator actions can be taken.

The valve position should be indicated in the control room. An alarm should be provided in conjunction with this indication.

The valve position indication may be safety grade. If the position indication is not safety grade, a reliable single-channel direct indication powered from a vital instrument bus may be provided if backup methods of determining valve position are available and are discussed in the emergency procedures as an aid to operator diagnosis of an action.

The valve position indication should be seismically qualified consistent with the component or system to which it is attached.

The position indication should be qualified for its appropriate environment (any transient or accident which would cause the relief or safety valve to lift) and in accordance with the Commission order on May 23rd, 1980 (CLI-80-21).

It is important that the displays and controls added to the control room as a result of this requirement do not increase the potential for operator error. A human-factor analysis should be performed taking into consideration:

(a) the use of this information by an operator during both normal and abnormal plant conditions,

(b) integration into emergency procedures,

(c) integration into operator training, and

(d) other alarms during emergency and need for prioritization of alarms.

Documentation should be provided that discusses each item of the clarification, as well as electrical schematics and proposed test procedures in accordance with the proposed review schedule, but in no case less than four months prior to the scheduled issuance of the staff safety evaluation report. Implementation must be completed prior to fuel load.

18.1.24.2 Interpretation

None required.

18.1.24.3 Statement of Response

Each of the safety/relief valves (SRVs) (16 per unit) is provided with an acoustic monitoring system to detect flow through the valve. An acoustic sensor is mounted on the discharge piping, downstream of each valve.

The monitors are grouped into two divisions with 8 valves each. Each division has group annunciation for valve opening and for division loss of power. A red annunciator window is

provided for valve opening and white annunciator window for loss of power on a front row control panel for these annunciations. Each division is powered from a 1E vital instrument bus.

Individual indication of an open valve is provided by a red light (1 light for each valve) on a front row control room panel (1C601). Individual indication of valve position is also available on a back row control room panel where the signal conditioning instruments are located.

The acoustic monitoring system is designed to be safety grade. Environmental qualification for post-accident harsh conditions is not required.

Additional design information is presented in Subsection 7.6.1b.1.6.

A human factors review of the front row control panel on which these indicators are located has been completed. This same analysis has been applied to the SRV position indicators added to this panel.

The use of tailpipe temperature detectors in the emergency procedures is discussed in a letter from N. W. Curtis to B. J. Youngblood on April 30, 1981 (PLA-736).

18.1.25 Auxiliary Feedwater System Evaluation (II.E.1.1)

This requirement is not applicable to Susquehanna SES.

18.1.26 Auxiliary Feedwater System Initiation AND Flow (II.E.1.2)

This requirement is not applicable to Susquehanna SES.

18.1.27 Emergency Power for Pressurizer Heaters (II.E.3.1)

This requirement is not applicable to Susquehanna SES.

18.1.28 Dedicated Hydrogen Penetrations (II.E.4.1)

18.1.28.1 Statement of Requirement

Plants using external recombiners or purge systems for post-accident combustible gas control of the containment atmosphere should provide containment penetration systems for external recombiner or purge systems that are dedicated to that service only. These systems must meet the redundance and single-failure requirements of General Design Criteria 54 and 56 of Appendix A to 10 CFR 50, and that are sized to satisfy the flow requirements of the recombiner or purge system.

The procedures for the use of combustible gas control systems following an accident that results in a degraded core and release of radioactivity to the containment must be reviewed and revised, if necessary.

Operating license applicants must have design changes completed by July 1, 1981 or prior to issuance of an operating license, whichever is later.

18.1.28.2 Interpretation

None required.

18.1.28.3 Statement of Response

Susquehanna SES design includes 100% redundant internal hydrogen recombiner systems for post-accident combustible gas (hydrogen) control. Therefore this requirement is not applicable to Susquehanna SES.

18.1.29 Containment Isolation Dependability (II.E.4.2)

18.1.29.1 Statement of Requirement

(1) Containment isolation system designs shall comply with the recommendations of Standard Review Plan (SRP) Section 6.2.4 (i.e., that there be diversity in the parameters sensed for the initiation of containment isolation).

(2) All plant personnel shall be given careful consideration to the definition of essential and nonessential systems, identify each system determined to be essential, identify each system determined to be nonessential, describe the basis for selection of each essential system, modify their containment isolation designs accordingly, and report the results of the reevaluation to the NRC.

(3) All nonessential systems shall be automatically isolated by the containment isolation signal.

(4) The design of control systems for automatic containment isolation valves shall be such that resetting the isolation signal will not result in the automatic reopening of containment isolation valves. Reopening of containment isolation valves shall require deliberate operator action.

(5) The containment setpoint pressure that initiates containment isolation for nonessential penetrations must be reduced to the minimum compatible with normal operating conditions.

(6) Containment purge valves that do not satisfy the operability criteria set forth in Branch Technical Position CSB 6-4 or the Staff Interim Position of October 23, 1979 must be sealed closed as defined in SRP 6.2.4, item II.3.f during operational conditions 1, 2, 3, and 4. Furthermore, these valves must be verified to be closed at least every 31 days.

(7) Containment purge and vent isolation valves must close on a high radiation signal.

Applicants for an operating license must be in compliance with positions 1 through 4 before receiving an operating license. Applicants must be in compliance with positions 5 and 7 by

July 1, 1981, and position 6 by January 1, 1981 or before they receive their operating license, whichever is later for each position.

18.1.29.2 Interpretations

From item 4, the opening of containment isolation valves must require a deliberate operator action.

From item 5, the containment isolation setpoint pressure should be optimized to prevent unnecessary isolations during normal operations. However, containment isolation must not be prevented or delayed during an accident.

18.1.29.3 Statement of Response

(1) Containment isolation signals are actuated by several sensed parameters (refer to Table 3.3.6.1-1 in the Technical Requirements Manual). This complies with SRP Subsection 6.2.4, Paragraph II-6.

(2) Each process line penetrating containment was reviewed to determine whether it is an essential or non-essential line for purposes of isolation requirements. The classification for each line is given in Table 18.1-10.

Justification for the classification as an essential or non-essential line was also developed and is provided in Table 18.1-11. Systems identified as essential are those which may be required to perform an indispensable safety function in the event of an accident. Non-essential systems are those not required during or after an accident. Since instrument lines are not governed by isolation signals but are equipped with a manual isolation valve followed by an excess flow check valve outside the containment, the review of these lines was limited to ensure compatibility with the penetration listing in Table 6.2-12a.

At penetrations 59 A&B, isolation valves 142002 A&B and 242002 A&B, in the instrument reference legs, which are backfilled by the CRD water, are disabled in the open position by design, to preclude the possibility of pressurization of the reference legs to CRD pressure, resulting in false pressure and level signals.

(3) All lines to non-essential systems are provided with isolation capability. All isolation valves in these lines, except the reactor water clean-up system (RWCU) discharge valves (HV-14182A/B) receive auto-isolation signals (refer to Table 18.1-10). The automatic containment isolation function for the RWCU discharge lines is provided by three containment series check valves (141-1F010A,B, 141818A,B and 141F039A,B) which prevents back flow from the reactor vessel. A remote manual motor-operated gate valve provides long term containment isolation for the RWCU discharge line (HV-14182A/B). The RWCU discharge isolation valves are not closed to prevent the loss of the filter cake in the RWCU filter demineralizer system and injection of resin into the vessel on restart of the RWCU system.

(4) All containment isolation valves, except those listed below, will not automatically open on logic reset.

a) The RCIC and HPCI turbine steam supply line isolation valves (HV-1F007, HV-1F008, HV-1F002 and HV-1F003) are normally open valves and will close upon a steam line break isolation signal. These valves are essential valves and do not receive a containment isolation signal. Reopening of these valves will occur if the hand switches are not placed in the closed position by the operator prior to actuation of the reset switch and the isolation parameters have cleared.

These valves are equipped with key-locked maintained contact switches to insure that these valves are open during ECCS initiation. If a pipe break condition were detected, then these valves will be automatically closed. After the pipe break problems are cleared these valves can be reopened to their normal emergency positions by deliberate operator action using the key-locked reset switches for each system. The operator is required to ensure that the valve switches are in the correct position prior to operating the keylock reset switch.

b) The inboard HPCI and RCIC isolation valves each have a pressure equalization valve (HV-1F100 and HV-1F088) around them. The equalization valves are normally closed and are only used to equalize the pressure around the inboard isolation valve in order to open them. If open, the valves will close upon a steam line break isolation signal. Reopening of these valves will occur if the hand switches are not placed in the closed position by the operator prior to actuation of the reset switch and the isolation parameters have cleared.

As with the HPCI/RCIC isolation valves the equalization valves will reopen upon deliberate manual logic reset using the key-locked reset switches. These valves must open in order to allow the inboard isolation valves to reopen to their normal emergency positions when the pipe break problems have cleared. If the equalization valve switches are not in the open position the operator must manually open them to equalize the pressure around the inboard HPCI/RCIC valves.

(c) The RHR containment isolation valves (HV-1F016A, B, and HV-1F028A, B) associated with the drywell and suppression pool spray lines will reopen if their handswitches are placed in the open position prior to actuation of the reset switch, the LPCI injection signals are clear, and the LPCI injection valves are closed. These spray line valves are normally closed and are provided key-locked hand switches and receive an isolation signal as described in Tables 18.1-10 and 18.1-12. If the valves were open before an LPCI injection event, these valves will automatically close and can not be reopened if the LPCI injection signals still exist or the LPCI injection valves are still open. This is to insure that the LPCI injection function will not be inadvertently jeopardized by opening of the spray line isolation valves. If these spray line valves were closed before the LPCI injection event, the valves will remain closed after reset even after all injection signals are clear and the LPCI injection valve are closed.

As noted in Table 18.1-10 only the outermost valve is considered a containment isolation valve for these penetrations. The three inboard valves HV-1F021A, HV-1F-27A and HV-1F024A are spring return to "AUTO" switches and will not automatically reopen after logic reset and all signals clear. These inboard valves have not been considered containment isolation valves because they can not be

leak tested in the "forward" direction. Since these valves effectively function as containment isolation valves, a logic reset will not automatically result in a breach of containment integrity for these penetrations.

5) The BWR Owners' Group has performed a generic analysis which is summarized as follows. The containment isolation analytical setpoint pressure for Mark I, II, and III containments is approximately 2 psig (drywell pressure). Under normal operating conditions, fluctuations in the atmospheric barometric pressure as well as heat inputs (from such sources as pumps) can result in containment pressure increases on the order of 1 psi. Consequently, the isolation setpoint of 2 psig provides a 1 psi margin above the maximum expected operating pressure. The 1 psi margin to isolation has proved to be a suitable value to minimize the possibility of spurious containment isolation. At the same time, it is such a low value (particularly in view of the small drywell volume of Mark I, II, and III containments) that it provides a very sensitive and positive means of detecting and protecting against breaks and leaks in the reactor coolant system. No change of the setpoint is necessary for these containment types.

   PP&L concurs with this position. Therefore, no modifications to the containment isolation pressure setpoint are necessary in response to this requirement.

6) The design of the containment atmosphere purge valves was reviewed against Branch Technical Position CSB6-4. This review identified several valves that do not meet these criteria. These valves will be qualified to meet this criteria as stated in a letter to B. J. Youngblood from N. W. Curtis on Apri1 1, 1981 (PLA-700). Valves in Unit 1 will be fully qualified prior to the startup following first refueling. Valves in Unit 2 will be qualified prior to Unit 2 fuel load.

7) Two redundant safety grade radiation monitors are installed down stream of the Standby Gas Treatment System. This signal is used to close the following containment isolation valves in the vent and purge system: HV-15703, HV-15704, HV-15705, HV-15711, HV-15713, HV-15714, HV-15721 HV-15722, HV-15723, HV-15724, HV-15725, SV-15737, and SV-15767.

   The radiation setpoint is set to so that the 10CFR 100 limits are not exceeded. The high radiation alarm for these detectors is annunciated on control room front row panel 1C653. The radiation level measured by these detectors is recorded on control room backrow panel 1C600.

18.1.30 Accident-Monitoring Instrumentation (II.F.1)

18.1.30.1 Statement of Requirement

The following equipment shall be added:

(1) Noble gas effluent radiological monitor;

(2) Provisions for continuous sampling of plant effluents for post-accident releases of radioactive iodines and particulates and onsite laboratory capabilities;

(3) Containment high-range radiation monitor;

(4) Containment pressure monitor;

(5) Containment water level monitor; and

(6) Containment hydrogen concentration monitor.

It is important that the displays and controls added to the control room as a result of this requirement not increase the potential for operator error. A human-factors analysis should be performed which considers:

(a) the use of this information by an operator during both normal and abnormal plant conditions,

(b) integration into emergency procedures,

(c) integration into operator training, and

(d) other alarms during emergency and need for prioritization of alarms.

Each piece of equipment is further discussed below.

18.1.30.1.1 Noble Gas Effluent Monitor

Noble gas effluent monitors shall be installed with an extended range designed to function during accident conditions as well as during normal operating conditions. Multiple monitors are considered necessary to cover the ranges of interest.

(1) Noble gas effluent monitors with an upper range capacity of 10^5 μCi/cc (Xe-133) are considered to be practical and should be installed in all operating plants.

(2) Noble gas effluent monitoring shall be provided for the total range of concentration extending from normal condition (as low as reasonably achievable concentrations to a maximum of 10^5 μCi/cc (Xe-133). Multiple monitors are considered to be necessary to cover the ranges of interest. The range capacity of individual monitors should overlap by a factor of ten.

Licensees and licensing applicants should have available for review the final design description of the as-built system, including piping and instrument diagrams together with either (1) a description of procedures for system operation and calibration, or (2) copies of procedures for system operation and calibration. License applicants will submit the above details in accordance with the proposed review schedule, but in no case less than four months prior to the issuance of an operating license.

18.1.30.1.2 Sampling and Analysis of Plant Effluents

Because iodine gaseous effluent monitors for the accident condition are not considered to be practical at this time, capability for effluent monitoring of radioiodines for the accident condition

shall be provided with sampling conducted by adsorption on charcoal or other media, followed by onsite laboratory analysis.

Licensees shall provide continuous sampling of plant gaseous effluent for post-accident releases of radioactive iodines and particulates to meet the requirements of Table II.F.1-2 in NUREG-0737. Licensees shall also provide onsite laboratory capabilities to analyze or measure these samples. This requirement should not be construed to prohibit design and development of radioiodine and particulate monitors to provide online sampling and analysis for the accident condition. If gross gamma radiation measurement techniques are used, then provisions shall be made to minimize noble gas interference.

The shielding design basis is given in Table II.F.1-2 of NUREG-0737. The sampling system design shall be such that plant personnel could remove samples, replace sampling media and transport the samples to the onsite analysis facility with radiation exposures that are not in excess of the criteria of GDC 19 of 5-rem whole-body exposure and 75 rem to the extremities during the duration of the accident.

The design of the systems for the sampling of particulates and iodines should provide for sample nozzle entry velocities which are approximately isokinetic (same velocity) with expected induct or instack air velocities. For accident conditions, sampling may be complicated by a reduction in stack or vent effluent velocities to below design levels, making it necessary to substantially reduce sampler intake flow rates to achieve the isokinetic condition. Reductions in air flow may well be beyond the capability of available sampler flow controllers to maintain isokinetic conditions; therefore, the staff will accept flow control devices which have the capability of maintaining isokinetic conditions with variations in stack or duct design flow velocity of ±20%. Further departure from the isokinetic condition need not be considered in design. Corrections for non-isokinetic sampling conditions, as provided in Appendix C of ANSI 13.1-1969 may be considered on an ad hoc basis.

Effluent streams which may contain air with entrained water, e.g., air ejector discharge, shall have provisions, e.g., heaters, to ensure that the adsorber is not degraded while providing a representative sample.

License applicants will submit final design details in accordance with the proposed review schedule, but in no case less than four months prior to the issuance of an operating license.

18.1.30.1.3 Containment High-Range Radiation Monitor

In containment radiation-level monitors with a maximum range of 10^8 rad/hr shall be installed. A minimum of two such monitors that are physically separated shall be provided. Monitors shall be developed and qualified to function in an accident environment.

The specification of 10^8 rad/hr in the above position was based on a calculation of post-accident containment radiation levels that include both particulate (beta) and photon (gamma) radiation. A radiation detector that responds to both beta and gamma radiation cannot be qualified to post-LOCA (loss-of-coolant accident) containment environments but gamma-sensitive instruments can be so qualified. In order to follow the course of an accident, a containment monitor that measures only gamma radiation is adequate. The requirement was revised in the October 30, 1979 letter to provide for a photon-only measurement with an upper range of 10^7 R/hr.

The monitors shall be located in containment(s) in a manner as to provide a reasonable assessment of area radiation conditions inside containment. The monitors shall be widely separated so as to provide independent measurements and shall "view" a large fraction of the containment volume. Monitors should not be placed in areas which are protected by massive shielding and should be reasonably accessible for replacement, maintenance, or calibration. Placement high in a reactor building dome is not recommended because of potential maintenance difficulties.

The monitors are required to respond to gamma photons with energies as low as 60 keV and to provide an essentially flat response for gamma energies between 100 keV and 3 MeV, as specified in Table II.F.1-3 of NUREG-0737. Monitors that use thick shielding to increase the upper range will under-estimate post-accident radiation levels in containment by several orders of magnitude because of their insensitivity to low energy gammas and are not acceptable.

License applicants will submit the required documentation in accordance with the appropriate review schedule, but in no case less than four months prior to the issuance of the staff evaluation report for an operating license.

18.1.30.1.4 Containment Pressure Monitor

A continuous indication of containment pressure shall be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

Operating license applicants with an operating license dated before January 1, 1982 must have design changes completed by January 1, 1982; those applicants with license dated after January 1, 1982 must have all design modifications completed before they can receive their operating license. Documentation is due 6 months for the expected date of operation.

18.1.30.1.5 Containment Water Level Monitor

A continuous indication of containment water level shall be provided in the control room for all plants. A wide range instrument shall be provided to cover the range from the bottom to 5 feet above the normal water level in the suppression pool. The containment wide-range water level indication channels shall meet appropriate design and qualification criteria. The narrow-range channel shall meet the requirements of Regulatory Guide 1.89. For BWR pressure-suppression containments, the emergency core cooling system suction line inlets may be used as a starting reference point for the narrow-range and wide-range water level monitors, instead of the bottom of the suppression pool.

The accuracy requirements of the water level monitors shall be provided and justified to be adequate for their intended function.

Operating license applicants with an operating license date before July 1, 1981 must have design changes completed by July 1, 1981, whereas those applicants with license dates past July 1, 1981 must have all design modifications completed before they can receive their operating license.

Submittals from operating reactors licensees and applicants for operating licenses (with an operating license date before January 1, 1982) shall be provided by January 1, 1982. Applicants with operating license dates beyond January 1, 1982 shall provide the required design information at least 6 months before the expected date of operation.

18.1.30.1.6 Containment Hydrogen Monitor

A continuous indication of hydrogen concentration in the containment atmosphere shall be provided in the control room. Measurement capability shall be provided over the range of 0 to 10% hydrogen concentration under both positive and negative ambient pressure.

The continuous indication of hydrogen concentration is not required during normal operation. If an indication is not available at all times, continuous indication and recording shall be functioning within 30 minutes of the initiation of safety injection.

Operating license applicants with an operating license date before January 1, 1982 must have design changes completed by January 1, 1982 must have all design modifications completed before they can receive their operating license.

Operating reactors and applicants for operating license receiving an operating license before January 1, 1982 will submit documentation before January 1, 1982. Applicants with operating license issued after January 1, 1982 shall provide the required design information at least 6 months prior to the expected date of operation.

18.1.30.2 Interpretation

None required.

18.1.30.3 Statement of Response

The response for each equipment requirement is given below. All equipment will be installed by the required dates. A human factors evaluation will be performed for changes that involve control room instrumentation. Drawings showing the location of equipment were submitted in a letter from N. W. Curtis to A. Schwencer on June 15 (PLA-842).

For modifications to plant systems and components such as addition of new post-accident monitoring capability, procedures are developed or revised as necessary and appropriate training is provided when the final design documents are approved and the equipment is available for use.

18.1.30.3.1 Noble Gas Effluent Monitor

Each of the five plant vents are monitored by a General Atomics-ESI Vent Effluent Radiation Monitoring System (VERMS) in compliance with NUREG-0737. The VERMS systems obtain representative samples of noble gas effluents for normal and accident conditions using sampling nozzle arrays and sample transport tubing in compliance with ANSI 13.1-1969.

The Turbine Building VERMS is described in Section 11.5.2.1.2 and the Standby Gas Treatment System VERMS is described in Section 11.5.2.1.3. Each Turbine Building and Standby Gas Treatment System systems VERMS are wide range gas monitors that have three noble gas detectors which provide overlapping ranges of concentration from 3.4×10^{-7} μCi/cc to 1×10^{5} μCi/cc for Xe-133 gas. The Reactor Building VERMS is described in Section 11.5.2.1.1. Each Reactor Building VERMS is a gas monitor that has a single low range noble gas detector which provides a concentration range of 3.4×10^{-7} μCi/cc to 3.4×10^{-1} μCi/cc for Xe-133 gas. This range covers all postulated accident conditions that will be seen by the Reactor Building VERMS before the Reactor Building Ventilation System is shutdown and isolated, due to high radiation in the Reactor Building or a loss of coolant accident, and Standby Gas Treatment used to provide Reactor Building Ventilation.

The vent effluent noble gas data and flows through each sample line and through the plant vents is continuously monitored and stored in non-volatile memory. VERMS calculates and stores total release rate in μCi/min for each vent. This information is displayed and recorded on control room back row panel 0C658. It is also sent to the plant process computer systems. This information can be displayed upon request. This information is also available in the Technical Support Center.

High effluent release rate alarms for all five vent stacks are annunciated on control room front row panel 0C653.

The low-range noble gas channel in all five systems is calibrated using certified Kr-85 and Xe-133 gas standards traceable to the National Institute of Standards and Technology (NIST). The mid-range and high-range noble gas channels in the Turbine Building and Standby Gas Treatment System systems were calibrated using certified Xe-133 and Kr-85 gas standards. After calibration the Xe-133 gas standard was verified by NIST.

The VERMS equipment is powered from reliable power sources. The VERMS human system interface, annunciator interface and plant computer interface equipment located in control room panel 0C658 are powered from non-class 1E instrument AC power that is backed up by uninterruptable power supplies. The VERMS monitoring and sampling instrumentation and control equipment and sample pumps located in the plant are powered from class 1E AC power, diesel generator backed engineered safety busses (refer to Section 8, Table 8.1-2 for sources). Power for alternate sampling equipment is provided a different source than the normal VERMS equipment power source.

During accident conditions under which the refueling floor is inaccessible, the Turbine Building and Standby Gas Treatment System sample flow will be diverted by motor operated valves from the collection cartridges/filters in the Normal Sample Conditioning Skid Assembly on the Refuel Floor to collection cartridges/filters in the Sample Conditioning Skid Assembly in the Turbine Building. Under accident conditions where high activity samples are detected, a reduced sample flow is diverted through shielded sample cartridges/filters on the Sample Conditioning Skid Assembly and then mid and high range noble gas detectors on the Sample Detection Skid Assembly. The range of the mid and high range noble gas detectors is 10^{-4} to 10^{+5} μCi/cc. The Turbine Building and Standby Gas Treatment vent monitoring equipment are located in the turbine building elevation 729' level. All pertinent data is available at the local control modules as well as in the main control room and in the Technical Support Center.

18.1.30.3.2 Sampling and Analysis of Plant Effluents

VERMS obtains a continuous sample from each of the five plant vents. To condition the vent flow for sampling, each vent has flow straightener and profiler sections to eliminate turbulent and rotating gas flow located upstream of the sample array. The average stack velocity is then measured by means of a multipoint, self-averaging, Pitot transverse flow element located between the profiler and the sample array. The vent flow signal is provided to VERMS. VERMS simultaneously withdraws a constant flow rate sample through a multipoint sample array. VERMS uses constant flow rate sampling because flow rate variations in the sample tubing have a much greater effect on particulate sample (composition) losses than the corresponding effect of deviations from true isokinetic flow at the sample nozzle. Sample tubing size is optimized to minimize losses at the sample flow rate. Correction factors have been calculated to account for anisokinetic sampling and sample transport losses in accordance with ANSI N13.1-1969. This approach provides for collection of the most representative vent sample given the variations of vent flow and the physical configuration of equipment.

Each sample is then transported through heat traced tubing to VERMS sampling and monitoring equipment. In VERMS the sample stream first passes through a filter/cartridge holder assembly for collection of particulates and iodines. Capabilities for back flushing the sample line with instrument air using manual control are provided. Upon leaving the filter holder the sample stream is monitored for noble gas activity and then returned to the plant vent. During normal operation the filters continuously collect representative samples of particulates and iodines for weekly laboratory analysis. Under accident conditions the filters must be removed and placed in a shielded container for transfer to a laboratory for analysis. VERMS also has provisions for obtaining noble gas grab samples and tritium samples.

The system is designed such that plant personnel can remove samples, replace sample media and transport the samples in shielded containers to an analysis facility. Radiation exposures for this process are not in excess of NUREG-0737 limits during the duration of the accident. These exposures are based on the proper use of plant procedures for removing sample media and doses from the shielding study presented in Section 18.1.20.

Procedures for analyzing samples both normal and accident conditions are described in Subsection 12.5.3.5.5. The equipment used to analyze these samples is described in Subsection 1.2.5.2.7.1. Additional instrumentation and procedures for sampling and analyzing implant iodine are described in Subsection 18.1.70.

18.1.30.3.3 Containment High-Range Radiation Monitor

Redundant Class 1E in-containment radiation monitors are provided. The monitors are General Atomic high range radiation monitors. These monitors are capable of measuring radiation levels of 1R/hr to 1 x 10^8 R/hr (Gamma) for photon energies of between 80 keV to 3 MeV. However, system accuracy will deviate from the performance goals specified in Regulatory Guide 1.97 Rev.2.

High containment temperatures post accident will decrease the in-containment cable insulation resistance (IR), resulting in decreased Containment High Radiation Monitor system accuracy. Assuming fully aged cable and maximum post accident temperatures, the reduced IR could cause a downscale offset error of up to 8 R/hr. While a correction factor will compensate for this

error, system information for the lower decades could still be outside the accuracy requirements of R.G. 1.97, Rev. 2.

R.G. 1.97, Rev. 2 specifies an accuracy within a factor-of-two (+100%, -50%) over the required range of 1 R/hr to 10^7 R/hr. The system installed to meet the commitments for a Primary Containment High Radiation Monitor is expected to perform as follows:

1. Containment Temperature #225° F
   Range: 1 R/hr to 10^7 R/hr
   Accuracy: +100%, -50%

2. Containment Temperature > 225° F
   Range: 500 R/hr to 10^7 R/hr
   Accuracy: +100%, -50%

3. Containment Temperature > 225° F
   Range: 1 R/hr to 500 R/hr
   Accuracy: +100%, -50% (plus a -8 R/hr bias shift)

A 25 R/hr correction factor is manually added to the indicated dose rate when containment temperature exceeds 225°F. This improves the accuracy of the information to within a factor of two, except for the range of 1 R/hr to 100 R/hr, where the information could be above the +100% accuracy bound by a maximum of 8 R/hr.

The detectors are unshielded and physically separated on opposite sides of the reactor pressure vessel.

Logarithmic indicating recorders are provided for Channels A and B on front row panel 1C601.

A common red high radiation annunciator for both channels is provided on control room front row panel 1C601. A common white system trouble light is also provided for both channels on control room front row panel 1C601.

The containment radiation monitoring system is designed to be safety grade. This equipment is qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-0588 in accordance with the Commission order on May 23rd, 1980 (CLI-80-21).

18.1.30.3.4 Containment Pressure Monitor

Two Class 1E redundant drywell chamber pressure measurements is provided as follows:

SERVICE	RANGE
LOCA Range	0 to 65 psig
HI Range	0 to 250 psig

The LOCA and HI ranges are divided into two divisions. Continuous, individual indication of all four Division I and II pressure measurements are provided by indicating recorders for the operation on front row panels 1C601.

Normal operating pressures in the drywell and wetwell are monitored by a -1 to +3 psig instrument installed in each chamber. An indicator on control panel 1C601 displays these pressures. A selector switch is provided to allow the operator to monitor either drywell or wetwell pressure. These instruments are non-safety grade with the exception of the transmitters, which are designed to meet containment pressure boundary service.

The accuracy of these instruments is ±2% of full scale.

The containment accident range pressure monitors are designed to be safety grade. This equipment is qualified to IEEE-344-1975, IEEE-323-1974 and NUREG-0588 in accordance with the Commission order on May 23, 1980 (CLI-80-21).

18.1.30.3.5 Containment Water Level Monitor

Redundant wide and narrow-range safety grade instruments are installed to continuously monitor suppression pool water level. The channel A measurements will be displayed on control room front row panel 1C601. The channel B measurements will be recorded on front row panel 1C601.

The narrow-range instruments measure between 18 and 26 feet. The wide-range instruments measure between 4.5 and 49 feet. This covers the required range of the lowest ECCS suction to 5 feet above normal water level. Normal water level is approximately 23 feet.

The accuracy of these instruments is ± of full-scale.

18.1.30.3.6 Containment Hydrogen Monitor

The continuous and redundant post-accident indication and recording of hydrogen are provided on control room front row panel 1C601. These instruments have a range of 0 to 30% and will be functioning within 30 minutes of the initiation of safety injection.

The containment hydrogen monitoring system is designed to be safety-grade. The equipment is qualified to IEEE-344-1975, IEEE-323-1974, and NUREG-0588 in accordance with the Commission order on May 23, 1980 (CLI-80-21).

The accuracy of these instruments is ±2% of full-scale.

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

18.1.31.1 Statement of Requirement

Licensees shall provide a description of any additional instrumentation or controls (primary or backup) proposed for the plant to supplement existing instrumentation (including primary coolant saturation monitors) in order to provide an unambiguous, easy-to-interpret indication of inadequate core cooling (ICC). A description of the functional design requirements for the system shall also be included. A description of the procedures to be used with the proposed equipment, the analysis used in developing these procedures, and a schedule for installing the equipment shall be provided.

18.1.31.2 Interpretation

None required.

18.1.31.3 Statement of Response

18.1.31.3.1 Introduction

PP&L has participated in the BWR Owners' Group (BWROG) study to specifically address ICC concerns. The purpose of the study was to evaluate means of providing reliable information to detect: the approach towards ICC, the existence of ICC, and the return to adequate core cooling. The study considered local and core-wide ICC, the reliability of existing instrumentation, and the impact of additional instrumentation.

The BWROG first evaluated the relationship between reactor water level and adequate core cooling. In order to clearly demonstrate that reactor water level is a viable indicator if ICC and due to the complexity of the issue, the BWROG scoped work into two activities. The first was to evaluate the reliability of the existing BWR reactor water level measurement systems. The second was a study of ICC. The report resulting from the first part was transmitted to NRC in a letter from T. J. Dente to H. R. Denton on August 13, 1982. The report resulting from the second part was transmitted to NRC. These reports provide substantial evidence to conclude that reactor water level is the most suitable parameter for operational control to avoid and mitigate ICC.

18.1.31.3.2 Reactor Water Level Instrumentation Report

The BWROG studied four types of reactor water level instrumentation which are representative of existing designs. The conclusion of the study was that the instrumentation used

> "through many years of operating experience have demonstrated very high degrees of capability to provide required information in various conditions of reactor operation. Almost without exception, the information presented to the operator is not ambiguous, and trips, initiations, and other signals taken from the level measurement systems have occurred as required."

The report goes on however to note a few reported events resulting in spurious signals and erroneous information to the operator, none of which resulted in serious consequences. The report indicates the desirability of an overall reassessment of the level system vulnerabilities against a list of potential areas of improvement. The report concludes that

> "no modifications should be made to any specific system until a thorough plant specific analysis is conducted. Interaction of systems in a specific plant design can significantly affect the degree of design change necessary to improve a system and may possibly demonstrate that a design change is not required."

18.1.31.3.3 Inadequate Core Cooling Report

The following concepts are extracted from the report on ICC.

1) Definition of ICC in terms of fuel and clad peak temperatures.

Clad temperatures in the range of 1300°F to 1500°F may likely result in the release of gaseous fission products in the fuel to clad gap by means of perforation produced by weakening of the fuel cladding. At temperatures in excess of 1800°F, clad metal-water chemical heat reaction commences and accelerates the heat rate. The report suggests that ICC might be defined as reaching peak temperatures between 1300°F and 1800°F in an average fuel bundle.

2) Operating states which might lead to ICC.

The relationship among reactor power, coolant inventory (water level), and recirculation flow which results in ICC is developed. The most extensive development of ICC results from operation at critical heat flux within the normal operating power range. Critical heat flux is treated extensively in present safety analyses and its occurrence is prevented by a substantial regulatory methodology including power-flow trip lines, limiting power distribution, and reactor trip systems. This rationale is extended down to zero flow and zero power including ICC conditions which may accompany high void fraction pumped recirculation flow.

From the above, the report concludes that the ICC requirements of NUREG-0737, item II.F.2 and Regulatory Guide 1.97 were not meant to be applicable to normal power range operation critical heat flux conditions, but apply to BWRs only at decay power conditions.

3) Water level as an indicator of ICC.

Applying only decay power conditions, a scenario was developed based on reactor scram, recirculation pump trip, reactor pressure vessel isolation, and loss of all makeup water systems (safety and non-safety). The steam produced by sensible and decay heat is assumed to be lost from the reactor pressure vessel at constant pressure. The time history of water level in this condition is shown in Figure 18.1-14. The relationship between water level and peak cladding temperature (which is an indicator of ICC) is shown in Figure 18.1-15. Sensitivity of this relationship to core uncovery times is shown to be very flat (see Figure 18.1-16). The assumption of a constant pressure (1,000 psia) was shown to be conservative as compared to a similar scenario at low pressure (100 psia) and a saw tooth shaped pressure function indicative of periodic safety/relief valve operation.

Accordingly it is concluded that reactor vessel water level is a valid indicator of ICC including approach to, existence of, and return from those conditions.

4) Local versus global detection of ICC.

A literature review indicated that core damage will not propagate once the core is recovered with water. A scenario is postulated that results in local fuel damage during the existence of global IFF, where the blockage prevents subsequent cooling of the

damaged channel. Damage propagation subsequent to global ICC recovery will be restricted to those bundles where sufficient fuel damage occurred during the global ICC to totally cut off the bundle water flow after recovery.

The use of instrumentation to detect this existence of local ICC was considered and rejected because bundle damage sufficient to cause complete blockage of cooling subsequent to recovery would also destroy any instrument placed therein.

5) Additional Instrumentation.

In addition to water level, there are a number of other existing instrument systems which provide information relative to the question of ICC. These include core spray flow rate, flows to and from the reactor vessel, primary containment radiation levels and hydrogen concentration levels, and activity sampling in reactor coolant water and the suppression pool.

6) Risk significance of ICC.

The contribution of water level measurement system failure to core melt probability was evaluated based on modifying an existing PRA for a BWR-4 plant with MARK II containment. The basic approach was to modify the event trees to identify the risk contributed by the water level system. Major concerns considered were: loss of level indication due to loss of reference leg under high drywell temperature and low vessel pressure conditions; concurrent or common failures of level instruments, and reference leg breaks. The results are considered to be representative of the Susquehanna design.

It is shown that water level measurement failures contribute less than 13% of the overall probability of core melt. Improvements in the level measurement system can reduce the contribution of level instrument failure to overall risk down to 13%. These improvements include reduction or mitigation of errors caused by high drywell temperatures, validation of level signals, and increasing the probability of timely ADS operation by manual actuation. Susquehanna has combined elements of these improvements in its design including reduced and equal vertical drops within primary containment for both the reference and variable legs of the multiple instrument channels which mitigate the effects of high drywell temperatures. In addition, the Susquehanna Emergency Operating Procedures (which are based on the BWROG Emergency Procedure Guidelines) provide assurance of timely manual ADS operation.

(7) Cost/Benefit of Additional Instrumentation.

An evaluation of alternative or diverse means of detecting ICC was conducted. Thirty-three concepts, listed in Table 18.1-18 were evaluated with many of these concepts being discarded after the preliminary evaluation. Finally, four devices were selected for further evaluation of performance and cost. These devices included: in-core thermocouples in the LPRM tubes; heated junction thermocouples as a point level measurement inside the LPRM tubes; steam dome thermocouples; source range monitors as an ICC detection device. A cost/benefit analyses, described in the report, was performed on these instrument system additions using a technique proposed in SECY-81-513 "Plan for Early Recognition of Safety Issues: August 25, 1981. The results of that analysis showed that the addition of alternative ICC detection devices could be assigned a low priority when compared to other LWR safety issues.

18.1.31.3.4 Conclusion

The BWROG study shows that knowledge of water level within the core is uniquely suitable and sufficient for the monitoring of the adequacy of core cooling under accident conditions. The existing water level measurement systems are highly reliable systems in providing information to the operator but that individual level measurement systems should be evaluated for possible improvements particularly with regard to loss of drywell cooling (which can produce flashing) and instrument line breaks.

Modifications can be made to reduce the probability of reactor water level instrumentation failure and thereby decrease its contribution to core melt from 13% to 3%. However, the Susquehanna design already includes a significant portion of the improvements identified by the BWROG.

The addition of back, diverse ICC detection devices is shown to have a very small additional contribution to overall risk reduction. Further, the safety priority analysis of these devices indicates a score in the lower end of the low priority range. Therefore, no additional instrumentation should be considered necessary for the detection of ICC because of its negligible contribution to plant safety.

Symptom-based procedures have been developed and implemented at Susquehanna Unit 1. These procedures will assist the operator in detecting the approach to ICC. Refer to Subsection 18.1.8 for the response to requirement I.C.I.

In addition, PP&L has developed a Display Control Sub-system (DCS) format to promote operator detection of inadequate core cooling. The format consists of three distinct functional areas: a graphic representation of reactor water level, a twenty minute reactor water level trend, and water level supporting data.

The graphic display will provide a qualitative representation of reactor water level from -150 to +170 inches relative to instrument level zero. Several vessel components are statically depicted as points of reference. The water level indication is normally displayed in yellow, however, of level decreases to or below -38 inches it will turn from yellow to red.

The reactor water level trend portion of the display will provide a twenty-minute history, in one minute increments, of the water trend. Slowly increasing or decreasing levels should be apparent from this trend. The trend display will turn from yellow to red if the level decreases to or below -38 inches.

Other supportive data, which may be useful in monitoring reactor water level, has also been provided.

The format is subject to possible revisions or refinements, however, the fundamental concept of graphically indicating reactor water level will always be provided by the display. A typical format sample is provided in Figure 18.1-13.

18.1.32 Emergency Power for Pressurizer Equipment (II.G.1)

This requirement is not applicable to Susquehanna SES.

18.1.33 Review ESF Valves (II.K.1.5)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.25 which contains the response to the requirement in NUREG-0694.

18.1.34 Operability Status (II.K.1.10)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.26 which contains the response to the requirement in NUREG-0694.

18.1.35 Trip Pressurizer Low-Level Coincident Signal Bistables (II.K.1.17)

This requirement is not applicable to Susquehanna SES.

18.1.36 Operator Training for Prompt Manual Reactor Trip (II.K.1.20)

This requirement is not applicable to Susquehanna SES.

18.1.37 Automatic Safety Grade Anticipatory Reactor Trip (II.K.1.21)

This requirement is not applicable to Susquehanna SES.

18.1.38 Auxiliary Heat Removal System Procedures (II.K.1.22)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.30 which contains the response to the requirement in NUREG-0694.

18.1.39 Reactor Vessel Level Procedures (II.K.1.23)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.31 which contains the response to the requirement in NUREG-0694.

18.1.40 Commission Orders on Babcock and Wilcox Plants (II.K.2)

These requirements are not applicable to Susquehanna SES.

18.1.41 Automatic Power-Operated Relief Valve Isolation System (II.K.3.1

This requirement is not applicable to Susquehanna SES.

18.1.42 Report on Power-Operated Relief Valve Failures (II.K.3.2)

This requirement is not applicable to Susquehanna SES.

18.1.43 Reporting Safety/Relief Valve Failures and Challenges (II.K.3.3)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.33 which contains the response to the requirement in NUREG-0694.

18.1.44 Automatic Trip of Reactor Coolant Pumps During A LOCA (II.K.3.5)

This requirement is not applicable to Susquehanna SES.

18.1.45 Evaluation of Power-Operated Relief Valve Opening Probability (II.K.3.7)

This requirement is not applicable to Susquehanna SES.

18.1.46 Proportional Integral Derivative Controller Modification (II.K.3.9)

This requirement is not applicable to Susquehanna SES.

18.1.47 Proposed Anticipatory Trip Modification (II.K.3.10)

This requirement is not applicable to Susquehanna SES.

18.1.48 Power-Operated Relief Valve Failure Rate (II.K.3.11)

This requirement is not applicable to Susquehanna SES.

18.1.49 Anticipatory Reactor Trip on Turbine Trip (II.K.3.12)

This requirement is not applicable to Susquehanna SES.

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

18.1.50.1 Statement of Requirement

Currently, the reactor core isolation cooling (RCIC) system and the high-pressure coolant injection (HPCI) system both initiate on the same low-water-level signal and both isolate on the same high-water-level signal. The HPCI system will restart on low water level but the RCIC system will not. The RCIC system is a low-flow system when compared to the HPCI system. The initiation levels of the HPCI and RCIC system should be separated so that the RCIC system initiates at a higher water level than the HPCI system. Further, the initiation logic of the RCIC system should be modified so that the RCIC system will restart on low water level. These

changes have the potential to reduce the number of challenges to the HPCI system and could result in less stress on the vessel from cold water injection. Analyses should be performed to evaluate these changes. The analyses should be submitted to the NRC staff and changes should be implemented if justified by the analyses.

All applicants for operating license should submit the results of an evaluation and proposed modifications four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date (July 1, 1981), whichever is later.

18.1.50.2 Interpretation

None required.

18.1.50.3 Statement of Response

PP&L concurs with the BWR Owners' Group position on the separation of the HPCI and RCIC setpoints which was transmitted to the NRC by letter from R. H. Buchholz (GE) to D. G. Eisenhut (NRC), October, 1, 1980 (MFN-169-80).

This letter forwarded a GE study which showed that HPCI and RCIC initiations at the current low water level setpoints is within the design basis thermal fatigue analysis of the reactor vessel and its internals. Separating HPCI and RCIC setpoints as a means of reducing thermal cycles has been shown to be of negligible benefit. In addition, raising the RCIC setpoint or lowering the HPCI setpoint have undesirable consequences which outweigh the benefit of the limited reduction in thermal cycles. Therefore, when evaluated on this basis, PP&L concludes that no change in RCIC or HPCI setpoints is required.

Based on early operating experience, the RCIC RPV low water initiation setting was raised several inches above the same HPCI setting in an effort to preclude HPCI System initiations.

PP&L also concurs with the BWR Owners' Group position that RCIC should restart automatically following a trip of the system at high reactor vessel water level. This position was transmitted to the NRC by letter from D. B. Waters (BWROG) to D. G. Eisenhut (NRC), December 29, 1980.

PP&L will implement the recommended option 2 which is described in detail in the GE study forwarded with the BWR Owners' Group position. Implementation is discussed in a letter from N. W. Curtis to B. J. Youngblood on May 20, 1981 (PLA-792).

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

18.1.51.1 Statement of Requirement

The high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems use differential pressure sensors on elbow taps in the steam lines to their turbine drives to detect and isolate pipe breaks in the systems. The pipe-break-detection circuitry has resulted in

spurious isolation of the HPCI and RCIC systems due to the pressure spike which accompanies startup of the systems. The pipe-break-detection circuitry should be modified so that pressure spikes resulting from HPCI and RCIC system initiation will not cause inadvertent system isolation.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date (July 1, 1981), whichever is later.

18.1.51.2 Interpretation

None required.

18.1.51.3 Statement of Response

The BWR Owners' Group has performed an evaluation and recommends the following modification to the steamline break detection logic. In order to minimize inadvertent HPCI/RCIC isolation due to pressure transients during system initiation, a time delay relay, set at approximately three (3) seconds, has been installed in the steamline high differential pressure circuitry. The time delay feature assures that the steamline break isolation signal is, in fact, due to continuous high steam flow. See Subsections 7.3.1.1a.1.3.4 and 7.6.1a.4.3.3.42.

The time delay relay is class 1E, with an adjustable time delay setting of 0-5 seconds. This classification is compatible with the system's existing circuitry. Two time delay relays are required for the trip system logic for both the HPCI and RCIC systems.

A design assessment study shall confirm the appropriate time-delay setting. Implementation is discussed in a letter from N. W. Curtis to B. J. Youngblood on May 20, 1981 (PLA-792).

18.1.52 Reduction of Challenges and Failures of Relief Valves (II.K.3.16)

18.1.52.1 Statement of Requirement

The record of relief-valve failures to close for all boiling-water reactors (BWRs) in the past 3 years of plant operation is approximately 30 in 73 reactor-years (0.41 failures per reactor-year). This has demonstrated that the failure of a relief valve to close would be the most likely cause of a small-break loss-of-coolant accident (LOCA). The high failure rate is the result of a high relief-valve challenge rate and a relatively high failure rate per challenge (0.16 failures per challenge). Typically, five valves are challenged in each event. This results in an equivalent failure rate per challenge of 0.03. The challenge and failure rates can be reduced in the following ways:

(1) Additional anticipatory scram on loss of feedwater,

(2) Revised relief-valve actuation setpoints,

(3) Increased emergency core cooling (ECC) flow,

(4) Lower operating pressures,

(5) Earlier initiation of ECC systems

(6) Heat removal through emergency condensers,

(7) Offset valve setpoints to open fewer valves per challenge,

(8) Installation of additional relief valves with a block- or isolation-valve feature to eliminate opening of the safety/relief valves (SRVs), consistent with the ASME Code,

(9) Increasing the high steam line flow setpoint for main steam line isolation valve (MSIV) closure,

(10) Lowering the pressure setpoint for MSIV closure,

(11) Reducing the testing frequency of the MSIVs,

(12) More-stringent valve leakage criteria, and

(13) Early removal of leaking valves

An investigation of the feasibility and contraindications of reducing challenges to the relief valves by use of the aforementioned methods should be conducted. Other methods should also be included in the feasibility study. Those changes which are shown to reduce relief-valve challenges without compromising the performance of the relief valves or other systems should be implemented. Challenges to the relief valves should be reduced substantially (by an order of magnitude).

Results of the evaluation shall be submitted by April 1, 1981 for staff review. The actual modification shall be accomplished during the next scheduled refueling outage following staff approval or no later than 1 year following staff approval. Modification to be implemented should be documented at the time of implementation.

18.1.52.2 Interpretation

None required.

18.1.52.3 Statement of Response

The BWR Owners' Group (BWROG) has performed an evaluation and developed recommendations to comply with this requirement. These recommendations were transmitted by a letter from B. D. Waters to D. G. Eisenhut on March 31, 1981. This evaluation shows that Crosby SRVs (as will be installed in Susquehanna) have a probability of sticking open which is approximately a factor of ten less than the three stage Target Rock valves. It is our understanding that the goal of this requirement is to reduce the probability of a stuck open SRV by a factor of 10 relative to a reference valve, which is the Target Rock valve. Therefore we meet the intent of this requirement without modifications. Implementation of the modification

proposed by the BWROG will not significantly reduce this failure probability. Therefore no modifications are necessary in response to this requirement.

18.1.53 Report On Outages Of Emergency Core Cooling Systems (II.K.3.17)

18.1.53.1 Statement of Requirement

Several components of the emergency core-cooling (ECC) systems are permitted by technical specifications to have substantial outage times (e.g., 72 hours for one diesel-generator; 14 days for the HPCI system). In addition, there are no cumulative outage time limitations for ECC systems. Licensees should submit a report detailing outage dates and lengths of outages for all ECC systems for the last 5 years of operation. The report should also include the causes of the outages (i.e., controller failure, spurious isolation).

18.1.53.2 Interpretation

None required.

18.1.53.3 Statement of Response

PP&L will submit a report which summarizes emergency core cooling system outages accumulated during the first five years of operation.

18.1.54 Modification of Automatic Depressurization System Logic (II.K.3.18)

18.1.54.1 Statement of Requirement

The automatic depressurization system (ADS) actuation logic should be modified to eliminate the need for manual actuation to assure adequate core cooling. A feasibility and risk assessment study is required to determine the optimum approach. One possible scheme that should be considered is ADS actuation on low reactor-vessel water level provided no high-pressure coolant injection or high-pressure coolant system flow exists and a low-pressure emergency core cooling system is running. This logic would complement, not replace, the existing ADS actuation logic.

Applicants for operating license shall provide results of feasibility study 1 year prior to issuance of operating license. A description of the proposed modification for staff approval is required four months prior to issuance of an operating license.

18.1.54.2 Interpretation

The ADS actuation logic may not be automatically actuated for steam line breaks (SLB) outside containment. The operator must manually actuate the ADS after diagnosing that an SLB has occurred. The ADS actuation logic should be modified to provide automatic actuation for all Design Basis Accidents.

18.1.54.3 Statement of Response

PP&L has committed to the NRC (PLA-1312) to modify the Automatic Depressurization System (ADS) logic in accordance with Option 4 of the BWROG study dated October 28, 1982. (Letter to Darrell G. Eisenhuth - NRC - from T. J. Dente - BWR Owners' Group - BWROG-8260.) This option bypasses the high drywell pressure portion of the current ADS actuation logic after a specific time interval and adds a manual switch which allows the operator to prevent an automatic ADS actuation. The additional logic does not affect automatic ADS response to pipe breaks inside the drywell. The analysis that led to the decision to implement this option is based on an assumption that the 2A fix is an acceptable resolution of the ATWS issue.

The high drywell pressure requirement is bypassed by installing a second ("bypass") timer that is actuated on low reactor water level (Level 1). When this timer runs out, the high drywell pressure trip is bypassed and the ADS is initiated on a low reactor water level signal alone. A manual ADS inhibit switch is also provided to aid the operator in the execution of certain steps in the Emergency Operating Procedures. To inhibit the ADS with the current logic, the operator must continuously reset the two-minute delay timer or turn off all of the low pressure ECCS pumps. Thus, the addition of a manually-operated inhibit switch would allow the operator to inhibit ADS actuation under ATWS conditions with a single action instead of having to repeatedly reset the existing two minute timer.

This option with procedural control provided by the Emergency Operating Procedures allows desirable operational control while providing automatic actions in time to prevent excessive fuel heatup.

The NRC has concluded (letter from A. Schwencer to N. W. Curtis dated 4/25/83) that Option 4 is an acceptable method of modifying the ADS logic. However, the following additional information is being submitted to the NRC to complete the review on Susquehanna:

a) Justification for the bypass timer setting.

b) A periodic testing plan for the timer.

c) Address the use of the manual inhibit switch in their emergency procedures.

d) A surveillance plan for the switch.

As stated in a letter from N. W. Curtis to A. Schwencer on June 17, 1981 (PLA-851), the required system modifications will be installed prior to the startup following the first refueling outage for Unit 1 and prior to fuel load for Unit 2 contingent on the results of the NRC review and contingent upon delivery of qualified equipment.

18.1.55 Restart of Core Spray And Low Pressure Coolant Injection Systems (II.K.3.21)

18.1.55.1 Statement of Requirement

The core-spray and low-pressure, coolant-injection (LPCI) system flow may be stopped by the operator. These systems will not restart automatically on loss of water level if an initiation signal

is still present. The core spray and LPCI system logic should be modified so that these systems will restart, if required, to assure adequate core cooling. Because this design modification affects several core-cooling modes under accident conditions, a preliminary design should be submitted for staff review and approval prior to making the actual modification.

All applicants for operating license should submit documentation four months prior to the expected issuance of an operating license or four months prior to the listed implementation date, whichever is later.

18.1.55.2 Interpretation

None required.

18.1.55.3 Statement of Response

PP&L concurs with the BWR Owners' Group position which was forwarded to the NRC by letter from D. B. Waters (BWROG) to D. G. Eisenhut (NRC), December 29, 1980.

The BWROG report states that the current ECCS design represents the optimum approach to BWR safety. No modifications to existing LPCI and core spray systems are necessary in response to this requirement.

18.1.56 Automatic Switchover of Reactor Core Isolation Cooling System Suction (II.K.3.22)

18.1.56.1 Statement of Requirement

The reactor core isolation cooling (RCIC) system takes suction from the condensate storage tank with manual switchover to the suppression pool when the condensate storage tank level is low. This switchover should be made automatically. Until the automatic switchover is implemented, licensees should verify that clear and cogent procedures exist for the manual switchover of the RCIC system suction from the condensate storage tank to the suppression pool.

Documentation must be submitted four months prior to issuance of the staff safety evaluation report or four months prior to the implementation date, whichever is later. Modifications shall be completed by January 1, 1982.

18.1.56.2 Interpretation

None required.

18.1.56.3 Statement of Response

Automatic switchover of the RCIC suction from the condensate storage tank (CST) to the suppression pool on low CST level has been installed at Susquehanna SES.

18.1.57 Confirm Adequacy of Space Cooling For High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems (II.K.3.24)

18.1.57.1 Statement of Requirement

Long-term operation of the reactor core isolation cooling (RCIC) and high-pressure coolant injection (HPCI) systems may require space cooling to maintain the pump-room temperatures within allowable limits. Licensees should verify the acceptability of the consequences of a complete loss of alternating-current (AC) power. The RCIC and HPCI systems should be designed to withstand a complete loss of offsite AC power to their support systems, including coolers, for at least 2 hours.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.57.2 Interpretation

Confirm that HPCI and RCIC room cooling can be maintained to enable continuous operation during a loss of offsite AC power for 2 hours.

18.1.57.3 Statement of Response

The HPCI and RCIC room unit coolers and their support systems are designed to withstand the consequences of a complete loss of offsite AC power since these are powered from onsite diesel generators. Each HPCI and RCIC room is provided with a 100% capacity redundant unit cooler. Refer to Subsection 9.4.2.2.

18.1.58 Effect of Loss of Alternating-Current Power on Recirculation Pump Seals (II.K.3.25)

18.1.58.1 Statement of Requirement

The licensees should determine, on a plant-specific basis, by analysis or experiment, the consequences of a loss of cooling water to the reactor recirculation pump seal coolers. The pump seals should be designed to withstand a complete loss of alternating-current (AC) power for at least 2 hours. Adequacy of the seal design should be demonstrated.

Applicants for operating licenses shall submit the evaluation and proposed modifications no later than 6 months prior to expected issuance of the staff safety evaluation report in support of license issuance, whichever is later. Modifications must be completed by January 1, 1982.

18.1.58.2 Interpretation

Evaluate the effect of a loss of offsite AC power for 2 hours on the recirculation pump seals.

18.1.58.3 Statement of Response

The system(s) providing cooling water to the recirculation pump seals will be modified to automatically receive emergency power following a loss of offsite power. These modifications are completed for Unit 1 and will be implemented on Unit 2.

18.1.59 Provide A Common Reference Level for Vessel Level Instrumentation (II.K.3.27)

18.1.59.1 Statement of Requirement

Different reference points of the various reactor vessel water level instruments may cause operator confusion. Therefore, all level instruments should be referenced to the same point. Either the bottom of the vessel or the top of the active fuel are reasonable reference points. All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.59.2 Interpretation

None required.

18.1.59.3 Statement of Response

All reactor water level indications use the same reference point, the bottom of the steam dryer skirt.

18.1.60 Verify Qualification of Accumulators on Automatic Depressurization System Valves (II.K.3.28)

18.1.60.1 Statement of Requirement

Safety analysis reports claim 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. GE has also stated that the emergency core cooling (ECC) systems are designed to withstand a hostile environment and still perform their function for 100 days following an accident. Licensee should verify that the accumulators on the ADS valves meet these requirements, even considering normal leakage. If this cannot be demonstrated, the licensee must show that the accumulator design is still acceptable.

The ADS valves, accumulators, and associated equipment and instrumentation must be capable of performing their functions during and following exposure to hostile environments and taking no credit for non-safety-related equipment or instrumentation. Additionally, air (or nitrogen) leakage through valves must be accounted for in order to assure that enough inventory of compressed air is available to cycle the ADS valves.

All applicants for operating license shall submit documentation four months before the expected issuance of the staff safety evaluation report for an operating license or four months before the listed implementation date, whichever is later.

18.1.60.2 Interpretation

None required.

18.1.60.3 Statement of Response

The design basis and justification for the ADS accumulators are given below. This design basis is different than stated in NUREG-0737, Requirement II.K.3.28.

The criteria for short-term and long-term ADS operations, as specified in the FSAR, are as follows:

(a) Short-Term ADS Operation -

Accumulator capacity is sufficient for each ADS valve to provide two actuations against 34.0 psig (70% of peak calculated) drywell pressure (see FSAR Subsection 5.2.2.4.1 and response to Question 211.67).

(b) Long-Term ADS Operability of 100 Days -

The safety related nitrogen storage system contains adequate gas in storage (N-bottles could be recharged periodically to provide capacity for at least 100 days operation of the ADS).

Justification for meeting these criteria is given below.

(1) Short-Term ADS Design Basis

Short-term is defined for this discussion as the time required to depressurize the reactor to the residual heat removal (RHR) shutdown cooling pressure permissive setpoint, stabilize the reactor water level and place the reactor in the shutdown cooling mode.

Each ADS accumulator is presently sized to provide two ADS safety/relief valve (S/RV) actuations at 70% of drywell design pressure. This is equivalent to five actuations of the ADS S/RVs at atmospheric pressure in the drywell. The ADS valves are designed to operate at 70% of drywell design pressure because that is the maximum pressure for which rapid reactor depressurization through the ADS valves is required (greater drywell pressures are associated only with the short duration primary system blowdown in the drywell immediately following a large pipe break). For large breaks which result in higher drywell pressure, sufficient reactor depressurization occurs due to the break to preclude the need for ADS. One ADS actuation at 70% of drywell design pressure is sufficient to depressurize the reactor and allow inventory makeup by the low pressure ECC

systems. However, for conservatism, the ADS accumulators are sized to allow two ADS actuations at 70% of drywell design pressure.

This design provides sufficient nitrogen to the ADS valves to permit depressurization until the RHR shutdown cooling mode can be initiated.

Preoperational testing of the ADS valves at 70% of design drywell pressure is not practical because it would require pressurizing the drywell during the ADS valve testing. Thus, an equivalent number of valve actuations at atmospheric pressure is normally included in the ADS system test specification.

(2) Long-Term ADS Design Basis

The basis for the long-term ADS requirement is derived from the long-term cooling acceptance criterion (Criterion 5) of 10CFR50.46. Criterion 5 states:

"Long-Term Cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

This criterion requires that either ADS be operable in conjunction with the low pressure ECCS pumps or that RHR shutdown cooling and water makeup capability be operable, to ensure long-term core cooling.

The primary purpose of long-term ADS is to keep the reactor pressure low enough so that low pressure ECCS systems can be used to keep the core cooled. The ADS is not required after the decay heat is low enough so the vessel will not be pressurized above the shutoff head of the low pressure ECCS pumps.

The duration for which the ADS must be available is dependent on factors such as the power of the reactor at the time of the LOCA, break size and location, available injection systems, and availability of RHR shutdown cooling. The long-term ADS design requirement is 100 days. This is based on a judgment of the time required to make any necessary repairs to the RHR shutdown cooling system or ADS, thus ensuring the core would be kept cool.

Based on the 10CFR50 requirement, a long-term (100 day) depressurization capability is provided by supplying nitrogen to the ADS accumulators using a safety grade system. The safety related nitrogen storage (N bottles) system contains adequate gas in storage for long term operation of the ADS after a postulated DBA. The N bottles have a 3-day storage capacity based on the system design leakage rate. After 3 days, the N bottles can be recharged indefinitely since the charging connections for the bottles are located in areas of the plant that are accessible under post-accident conditions.

FSAR Drawings 18.1-1 through 18.1-8 show plant radiation zones (dose rates) for a DBA post LOCA source term. Furthermore, the zones list the maximum

value of dose rate that would be present for an area irrespective of the time for the duration of the accident. The dose rates are based upon a Large Break DBA LOCA. For other events this source term would not be present and the dose would be of a lesser magnitude permitting access.

From the above discussion, PP&L concludes that the Susquehanna design of ADS pneumatic supply system meets the intent of NUREG-0737, Item II.K.3.28.

18.1.61 Revised Small-Break Loss of Coolant Accident Methods (II.K.3.30)

18.1.61.1 Statement of Requirement

The analysis methods used by nuclear steam supply system vendors and/or fuel suppliers for small-break loss-of-coolant accident (LOCA) analysis for compliance with Appendix K to 10 CFR Part 50 should be revised, documented and submitted for NRC approval. The revisions should account for comparisons with experimental data, including data from the LOFT test and Semiscale Test facilities.

The Bulletins and Orders Task Force identified a number of concerns regarding the adequacy of certain features of small-break LOCA models, particularly the need to confirm specific model features (e.g., condensation heat transfer rates) against applicable experimental data. These concerns, as they applied to each light-water reactor (LWR) vendor's models, were documented in the task force also concluded that, in light of the TMI-2 accident, additional systems verification of the small-break LOCA model as required by II.4 of Appendix K to 10 CFR 50 was needed. This included providing experimental verification of the various modes of single-phase and two-phase natural circulation predicted to occur in each vendor's reactor during small-break LOCAs.

Based on the cumulative staff requirements for additional small-break LOCA model verification, including both integral system and separate effects verification, the staff considered model revision as the appropriate method for reflecting any potential upgrading of the analysis methods.

The purpose of the verification was to provide the necessary assurance that the small-break LOCA models were acceptable to calculate the behavior and consequences of small primary system breaks. The staff believes that this assurance can alternatively be provided, as appropriate, by additional justification of the acceptability of present small-break LOCA models with regard to specific staff concerns and recent test data. Such justification could supplement or supersede the need for model revision.

The specific staff concerns regarding small-break LOCA models are provided in the analysis sections of the B&O Task Force reports for each LWR vendor, (NUREG-0635, -0565, -0626, -0611, and -0623). These concerns should be reviewed in total by each holder of an approved emergency core cooling system model and addressed in the evaluation as appropriate.

The recent tests include the entire Semiscale small-break test series and LOFT Tests (L3-1) and L3-2). The staff believes that the present small-break LOCA models can be both qualitatively and quantitatively assessed against these tests. Other separate effects tests (e.g., ORNL core uncovery tests) and future tests, as appropriate, should also be factored into this assessment.

Based on the preceding information, a detailed outline of the proposed program to address this issue should be submitted. In particular, this submittal should identify (1) which areas of the models, if any, the licensee intends to upgrade, (2) which areas the licensee intends to address by further justification of acceptability, (3) test data to be used as part of the overall verification/upgrade effort, and (4) the estimated schedule for performing the necessary work and submitting this information for staff review and approval.

Licensees shall submit an outline of a program for model justification/revision by November 15, 1980. Licensees shall submit additional information for model justification and/or revised analysis model for staff approval by January 1, 1982. Licensees shall submit their plant-specific analyses using the revised models by January 1, 1983 or one year after any model revisions are approved. Applicants shall submit appropriate information in accordance with the licensing review schedule.

18.1.61.2 Interpretation

None required.

18.1.61.3 Statement of Response

PP&L considers that the reactor vendor, General Electric, is the most appropriate party to work with the staff in resolving staff concerns with small break LOCA models for BWRs. Accordingly, the staff should direct their questions regarding the scope and schedule for this requirement to General Electric (attn. R. H. Buchholz, Manager, BWR Systems Licensing). Copies of correspondence on this item should be sent to PP&L so that we may remain cognizant of the progress of the program to resolve the staff's concerns on this requirement.

18.1.62 Plant-Specific Calculations To Show Compliance with 10CFR Part 50.46 (II.K.3.31)

18.1.62.1 Statement of Requirement

Plant-specific calculations using NRC-approved models for small-break loss-of-coolant accidents (LOCAs) as described in item II.K.3.30 to show compliance with 10 CFR 50.46 should be submitted for NRC approval by all licensees.

18.1.62.2 Interpretation

None required.

18.1.62.3 Statement of Response

Plant specific calculations will be performed, if required, following NRC approval of LOCA model revisions required by item II.K.3.30 (see Subsection 18.1.61).

18.1.63 Evaluation of Anticipated Transients with Single Failure To Verify No Fuel Cladding Failure (II.K.3.44)

18.1.63.1 Statement of Requirement

For anticipated transients combined with the worst single failure an assuming proper operator actions, licensees should demonstrate that the core remains covered or provide analysis to show that no significant fuel damage results from core uncovery. Transients which result in a stuck-open relief valve should be included in this category.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.63.2 Interpretation

None required.

18.1.63.3 Statement of Response

The BWR Owners' Group has prepared a generic response to this requirement. The report was transmitted to D. G. Eisenhut by a letter from D. B. Waters on December 29, 1980. This response contains an evaluation of analyses performed to demonstrate the core remains covered or no significant fuel damage occurs from an anticipated transient with a single failure. PP&L has reviewed this response and finds it is applicable to Susquehanna SES. The report concludes that the core remains covered for all evaluated combinations of anticipated transients and single failures.

18.1.64 Evaluation of Depressurization With Other Than The Automatic Depressurization System (II.K.3.45)

18.1.64.1 Statement of Requirement

Analyses to support depressurization modes other than full actuation of the automatic depressurization system (ADS) (e.g., early blowdown with one or two safety relief valves) should be provided. Slower depressurization would reduce the possibility of exceeding vessel integrity limits by rapid cooldown.

All applicants for operating license should submit documentation four months prior to the expected issuance of the staff safety evaluation report for an operating license or four months prior to the listed implementation date, whichever is later.

18.1.64.2 Interpretation

None required.

18.1.64.3 Statement of Response

The BWR Owners' Group submitted a generic response to this requirement. This response was transmitted by letter to D. G. Eisenhut from D. B. Waters on December 29, 1980. PP&L has reviewed this response and find it applicable to Susquehanna SES. The report concludes that no improvement can be gained by a slower depressurization and actually could be detrimental to core cooling. Therefore no additional action is necessary in response to this requirement.

18.1.65 Michelson Concerns (II.K.3.46)

18.1.65.1 Statement of Requirement

A number of concerns related to decay heat removal following a very small break LOCA and other related items were questioned by Mr. C. Michelson of the Tennessee Valley Authority. These concerns were identified for PWRs. GE was requested to evaluate these concerns as they apply to BWRs and to assess the importance of natural circulation during a small-break LOCA in BWRs.

18.1.65.2 Interpretation

None required.

18.1.65.3 Statement of Response

The General Electric Company has responded to the questions posed by Mr. Michelson. This response was sent by letter from R. H. Buchholz to D. F. Ross on February 21, 1980. These responses are applicable to Susquehanna SES and no further response is necessary.

18.1.66 Emergency Preparedness-Short Term (III.A.1.1)

No requirement stated in NUREG-0737. Refer to Subsection 18.2.38 which contains the response to the requirement in NUREG-0694.

18.1.67 Upgrade Emergency Support Facilities (III.A.1.2)

18.1.67.1 Statement of Requirement

A detailed statement of the requirement can be found in NUREG-0696. The implementation schedule was announced in Generic Letter 81-10 on February 18, 1981. This schedule is as follows: Design information for emergency response facilities should be provided in connection with the operating license review process. These facilities shall be operational by October 1, 1982 or prior to fuel load, whichever is later. Interim facilities, as described in NUREG-0694 shall be provided by fuel load.

18.1.67.2 Interpretation

None required.

18.1.67.3 Statement of Response

The proposed method of responding to this requirement was submitted by a letter to B. J. Youngblood from N. W. Curtis on April 2, 1981 (PLA-704). Details on the emergency response facilities are presented in the Emergency Plan.

18.1.68 Emergency Preparedness-Long Term (III.A.2)

18.1.68.1 Statement of Requirement

Each nuclear facility shall upgrade its emergency plans to provide reasonable assurance that adequate protective measures can and will be taken in the event of a radiological emergency. Specific criteria to meet this requirement is delineated in NUREG-0654 (FEMA-REP-1), "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparation in Support of Nuclear Power Plants."

NUREG-0654, Revision 1; NUREG-0696, "Functional Criteria for Emergency Response Facilities;" and the amendments to 10 CFR Part 50 and Appendix E to 10 CFR Part 50 regarding emergency preparedness, provide more detailed criteria for emergency plans, design, and functional criteria for emergency response facilities and establishes firm dates for submission of upgraded emergency plans for installation of prompt notification systems. These revised criteria and rules supersede previous Commission guidance for the upgrading of emergency preparedness at nuclear power facilities.

Requirements of the new emergency-preparedness rules under paragraphs 50.47 and 50.54 and the revised Appendix E to Part 50 taken together with NUREG-0654 Revision 1 and NUREG-0696, when approved for issuance, go beyond the previous requirements for meteorological programs. To provide a realistic time frame for implementation, a staged schedule has been established with compensating actions provided for interim measures.

Specific milestones have been developed and are presented below.

Milestones are numbered and tagged with the following code; a-date, b-activity, c-minimum acceptance criteria. They are as follows:

(1) a. Fuel load.

b. Submittal of radiological emergency response plans.

c. A description of the plan to include elements of NUREG-0654, Revision 1, Appendix 2.

(2) a. Fuel load.

b. Submittal of implementing procedures.

c. Methods, systems, and equipment to assess and monitor actual or potential offsite consequences of a radiological emergency condition shall be provided.

(3) a. Fuel load.

b. Implementation of radiological emergency response plans.

c. Four elements of Appendix 2 to NUREG-0654 with the exception of the Class B model of element 3, or

Alternative to item (3) requiring compensating actions:

A meteorological measurements program which is consistent with the existing technical specifications as the baseline or an element 1 program and/or element 2 system of Appendix 2 to NUREG-0654, or two independent element 2 systems shall provide the basic meteorological parameters (wind direction and speed and an indicator or atmospheric stability) on display in the control room. An operable dose calculational methodology (DCM) shall be in use in the control room and at appropriate emergency response facilities.

The following compensating actions shall be taken by the licensee for this alternative:

(i) If only element 1 <u>or</u> element 2 is in use:

- The licensee (the person who will be responsible for making offsite dose projections) shall check communications with the cognizant National Weather Service (NWS) first order station and NWS forecasting station on a monthly basis to ensure that routine meteorological observations and forecasts can be accessed.

- The licensee shall calibrate the meteorological measurements program at a frequency no less than quarterly and identify a readily available source of meteorological data (characteristic of site conditions) to which they can gain access during calibration periods.

- During conditions of measurements system unavailability, an alternate source of meteorological data which is characteristic of site conditions shall be identified to which the licensee can gain access.

- The licensee shall maintain a site inspection schedule for evaluation of the meteorological measurements program at a frequency no less than weekly.

- It shall be a reportable occurrence if the meteorological data unavailability exceeds the goals outline in Proposed Revision 1 to Regulatory Guide 1.23 on a quarterly basis.

(ii) The portion of the DCM relating to the transport and diffusion of gaseous effluents shall be consistent with the characteristics of the Class A model outlined in element 3 of Appendix 2 to NUREG-0654.

(iii) Direct telephone access to the individual responsible for making offsite dose projections (Appendix E to 10 CFR Part 50(IV)(A)(4)) shall be available to the NRC in the event of a radiological emergency. Procedures for establishing contact and identification of contact individuals shall be provided as part of the implementing procedures.

This alternative shall not be exercised after July 1, 1982. Further, by July 1, 1981, a functional description of the upgraded programs (four elements) and schedule for installation and full operational capability shall be provided (see milestones 4 and 5).

(4) a. March 1, 1982.

b. Installation of Emergency Response Facility hardware and software.

c. Four elements of Appendix 2 to NUREG-0654, with exception of the Class B model of element 3.

(5) a. July 1, 1982.

b. Full operational capability of milestone 4.

c. The Class A model (designed to be used out to the plume exposure EPZ) may be used in lieu of Class B model out to the ingestion EPZ. Compensating actions to be taken for extending the application of the Class A model out to the ingestion EPZ include access to supplemental information (meso- and synoptic scale) to apply judgment regarding intermediate and long-range transport estimates. The distribution of meteorological information by the licensee should be as described in Table 18.1-13 by July 1, 1982.

(6) a. July 1, 1982 or at the time of the completion of milestone 5, whichever is sooner.

b. Mandatory review of the DCM by the licensee.

c. Any DCM in use should be reviewed to ensure consistency with the operational Class A model. Thus, actions recommended during the initial phases of a radiological emergency would be consistent with those after the TSC and EOF are activated.

(7) a. September 1, 1982.

b. Description of the Class B model provided to the NRC.

c. Documentation of the technical bases and justification for selection of the type Class B model by the licensee with a discussion of the site-specific attributes.

(8) a. June 1, 1983.

b. Full operational capability of the Class B model.

c. Class B model of element 3 of Appendix 2 to NUREG-0654, Revision 1

Applicants for an operating license shall meet at least milestones 1, 2, and 3 prior to the issuance of an operating license. Subsequent milestones shall be met by the same dates indicated for operating reactors. For the alternative to milestone 3, the meteorological measurements program shall be consistent with the NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," Section 2.3.3 program as the baseline or element 1 and/or element 2 systems.

18.1.68.2 Interpretation

None required.

18.1.68.3 Statement of Response

Responses to these requirements are incorporated into the Emergency Plan.

18.1.69 Integrity of Systems Outside Containment Likely to Contain Radioactive Material (III.D.1.1)

18.1.69.1 Statement of Requirement

Applicants shall implement a program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as-low-as-practical levels. This program shall include the following:

(1) Immediate leak reduction.

(a) Implement all practical leak reduction measures for all systems that could carry radioactive fluid outside of containment.

(b) Measure actual leakage rates with system in operation and report them to the NRC.

(2) Continuing Leak Reduction--Establish and implement a program of preventive maintenance to reduce leakage to as-low-as-practical levels. This program shall include periodic integrated leak tests at intervals not to exceed each refueling cycle.

This requirement shall be implemented prior to issuance of a full-power license.

Applicants shall provide a summary description, together with initial leak-test results, of their program to reduce leakage from systems outside containment that would or could contain primary coolant or other highly radioactive fluids or gases during or following a serious transient or accident. Applicants shall submit this information at least four months prior to fuel load.

18.1.69.2 Interpretation

None required.

18.1.69.3 Statement of Response

1. Program summary description:

   1.1 The following systems will be leak tested (the frequency is indicated in ( ) after each item):

A.	Residual Heat Removal	(refueling cycle)
B.	Reactor Core Isolation Cooling	"
C.	Core Spray	"
D.	High Pressure Core Injection	"
E.	Scram Discharge	"
F.	Reactor Water Clean-up**	"
G.	Standby Gas Treatment	***
H.	Containment Air Monitors	(refueling cycle)****
I.	Post Accident Sampling	"
J.	Standby Liquid Control *****	”

   Initial leak-test results will be available when the first measurements are made, prior to completion of the startup test program.

   1.2 The following systems contain radioactive material but are excluded from our program (justification for exclusion follows each item):

____

* The RWCU system will not have significant post-accident radioactivity because the suction is isolated by containment isolation signals (refer to Table 18.1-10). However, this system may conceivably be used in some post-accident scenarios, and will therefore be leak-tested.

** Standby Gas Treatment is subject to filter efficiency testing in accordance with Technical Specifications per Section 18.1.69.3.2.A below.

*** Containment Air Monitors consist of the Containment Hydrogen/Oxygen Analyzers and gaseous portions of the Post Accident Sampling System.

**** Standby liquid control is not a system that recirculates radioactive fluid post-accident and hence, is not a system that is subject to testing under Technical Specification 5.5.2. However, the portion of the system between the primary containment wall and the explosive valves can contain radioactive fluid post-accident. Therefore, this portion of the Standby Liquid Control System is included in the leakage quantification test program and is combined with the above systems to be less than the acceptance criteria established for these systems.

A. Main Steam and Main Steam Line Drain - the main steam piping and drain line system may contain radioactive gases following a DBA-LOCA using the Isolated Condenser Treatment Method (ICTM); however, both the main steam lines and associated drain line are required to be leak tight in order to maintain normal operating performance. Any degradation in these systems would be detected through heat balance determinations, system performance indicators, and plant sensors. Any leaking component would be repaired or sealed as soon as reasonably possible. Therefore, post accident leakage of radioactive gases from this system is highly unlikely and may be excluded from the program.

B. Feedwater - identified by NEDO-24782 as not to be regarded as containing highly radioactive fluid following an accident.

C. Reactor Water Sample - this system is not required following an accident. Post-accident samples can be taken utilizing the Post-Accident Sampling system.

D. Recirculation Pump Seal Water (from CRD pumps) - lines are protected by check valves and excess flow check valves.

E. Floor & Equipment Drains - this system isolated following a LOCA and will not be used following an accident.

F. Suppression Pool Clean-up & Drain - same justification as E.

1.3 Method for obtaining actual leak rates

A. Water - leakage will be measured to determine a GPM leak rate. Implementing procedures will establish criteria for initiation of leak rate quantification.

B. Steam - an estimate of the size of the leak will be made (i.e. equivalent pipe diameter steam flow). Flowrate will be determined using standard Handbook data. This will be converted to a GPM flowrate using the specific volume of the steam at the given conditions. Alternatively, flowrate may be determined based on empirical data generated during steam leak rate testing.

2. The two gaseous systems are tested as follows:

A. Standby Gas Treatment System - This system is subject to filter efficiency testing in accordance with the Technical Specifications which includes "DOP" and refrigerant injection.

B. Containment Air Monitors - These are tested at the maximum pressure that the system will be exposed to under post accident conditions.

3. Consideration was given to the Standby Gas system regarding the incident at North Anna Unit 1 in 1979. The standby gas piping and ductwork from the containment to the filters are gas tight and do not include any pressure relief

devices which would allow gases to escape to the Reactor Building. The piping is rated at 150 psig and the ductwork is HVM-GS-G (High Velocity Medium Pressure - Galvanized Steel - Gas tight).

In light of the above, the actions stated in 1.1.G and 2.A have resulted.

4. Technical Specifications references this program which includes an acceptance criteria of 2.5 GPM total leakage rate for the systems listed in 1.1 with the exception of:

   A. Standby Gas Treatment - which is limited to the acceptance criteria stated in Technical Specifications Subsection 3.6.4.3 and

   B. The containment air monitors – which have demonstrated leakage as-low-as practical for this system such that measured leakage when added to the total containment leakage for Type B or C tests, does not exceed the acceptance criteria of $0.6L_a$.

   C. Standby Liquid Control – leakage from this system is measured in accordance with the Leakage Quantification Program and combined with leakage from the systems listed in 1.1 to be less than 2.5 gpm.

5. The total water leakage from the systems listed in 1.1 and the CRD Insert/Withdrawal lines described in Section 6.2.4.3.2.3, shall be $\leq$ 20 gpm.

18.1.70 Inplant Iodine Radiation Monitoring (III.D.3.3)

18.1.70.1 Statement of Requirement

Each licensee shall provide equipment and associated training and procedures for accurately determining the airborne iodine concentration in areas within the facility where plant personnel may be present during an accident.

Effective monitoring of increasing iodine levels in the buildings under accident conditions must include the use of portable instruments using sample media that will collect iodine selectively over xenon (e.g., silver zeolite) for the following reasons:

(1) The physical size of the auxiliary and/or fuel handling building precludes locating stationary monitoring instrumentation at all areas where airborne iodine concentration data might be required.

(2) Unanticipated isolated "hot spots" may occur in locations where no stationary monitoring instrumentation is located.

(3) Unexpectedly high background radiation levels near stationary monitoring instrumentation after an accident may interfere with filter radiation readings.

(4) The time required to retrieve samples after an accident may result in high personnel exposures if these filters are located in high-dose-rate areas.

After January 1, 1981, each applicant and licensee shall have the capability to remove the sampling cartridge to a low-background, low-contamination area for further analysis. Normally, counting rooms in auxiliary buildings will not have sufficiently low backgrounds for such analyses following an accident. In the low background area, the sample should first be purged of any entrapped noble gases using nitrogen gas or clean air free of noble gases. The licensee shall have the capability to measure accurately the iodine concentrations present on these samples under accident conditions. There should be sufficient samplers to sample all vital areas.

18.1.70.2 Interpretation

PP&L is in basic agreement with the technical discussion as outlined in this requirement. It should be noted that Susquehanna SES is a BWR and does not possess an auxiliary building. Consequently, it is premature to suggest that our counting facilities within the control structure will be inadequate to effectively count air samples. Additionally, purging of the air sample cartridges may not be necessary if an effective collection media is used for radioiodine air sampling.

18.1.70.3 Statement of Response

PP&L will meet the requirements defined in this item. To summarize the program, three (3) particulate and gaseous continuous air monitoring systems are provided for air sampling plant areas where personnel may be present during accident conditions. The systems are cart mounted for ease of relocation.

Grab samples are obtained using the equipment specified in Subsection 12.5.2.6.3. During accident conditions silver zeolite cartridges will be used for radioiodine analysis in conjunction with two (2) Eberline stabilized assay meters (SAM-2) or equivalent.

Air samples are evaluated as specified in Subsection 12.5.3.5.5. In addition to initial training provided for Health Physics personnel, periodic drills are conducted in accordance with the Susquehanna Emergency Plan Section 9.1.2 (See Amendment 25 of Operating License Application).

Analysis of iodine cartridges will be performed in a low background, low contamination area. During accident conditions, preliminary analysis will be performed by onsite radiation monitoring teams in the counting room, if accessible using a SAM-2. Final analysis will be performed in the emergency off-site facility where appropriate sensitivity can be achieved. Prior to analysis, cartridges will be purged using station service air or bottled nitrogen, if necessary to reduce noble gas interference.

18.1.71 Control Room Habitability Requirements (III.D.3.4)

18.1.71.1 Statement of Requirement

Licensees shall assure that control room operators will be adequately protected against the effects of accidental release of toxic and radioactive gases and that the nuclear power plant can

be safely operated or shut down under design basis accident conditions (Criterion 19, "Control Room," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50).

All licensees must make a submittal to the NRC regardless of whether or not they met the criteria of the Standard Review Plans (SRP) sections listed below. The new clarification specifies that licensees that meet the criteria of the SRPs should provide the basis by referencing past submittals to the NRC and/or providing new or additional information to supplement past submittals.

18.1.71.1.1 Requirements for Licensees that Meet Criteria

All licensees with control rooms that meet the criteria of the following sections of the Standard Review Plan:

2.2.1-2.2.2	Identification of Potential Hazards in Site Vicinity
2.2.3	Evaluation of Potential Accidents;
6.4	Habitability Systems

shall report their findings regarding the specific SRP sections as explained below. The following documents should be used for guidance:

(a) Regulatory Guide 1.78, "Assumptions for Evaluating the Habitability of Regulatory Power Plant Control Room During a Postulated Hazardous Chemical Release"; and,

(b) K. G. Murphy and K. M. Campe, "Nuclear Power Plant Control Room Ventilation System Design for Meeting General Design Criterion 19," 13th AEC Air Cleaning Conference, August 1974

Licensees shall submit the results of their findings as well as the basis for those findings by January 1, 1981. In providing the basis for the habitability finding, licensees may reference their past submittals. Licensees should, however, ensure that these submittals reflect the current facility design and that the information requested in Attachment 1 of NUREG-0737 is provided.

18.1.71.1.2 Requirements for Licensees that Do Not Meet Criteria

All licensees with control rooms that do not meet the criteria of the above-listed references, Standard Review Plans, Regulatory Guides, and other references shall perform the evaluations and identify appropriate modifications, as discussed below.

Each licensee submittal shall include the results of the analyses of control room concentrations from postulated accidental release of toxic gases and control room operator radiation exposures from airborne radioactive material and direct radiation resulting from design-basis accidents. The toxic gas accident analysis should be performed for all potential hazardous chemical releases occurring either on the site or within 5 miles of the plant-site boundary. Regulatory Guide 1.78 lists the chemicals most commonly encountered in the evaluation of control room habitability but is not all inclusive.

The design-basis-accident (DBA) radiation source term should be for the loss-of-coolant accident LOCA containment leakage and engineered safety feature (ESF) leakage contribution outside containment as described in Appendix A and B of Standard Review Plan Chapter 15.6.5. In addition, boiling-water reactor (BWR) facility evaluations should add any leakage from the main steam isolation valves (MSIV) (i.e., valve-stem leakage, valve seat leakage, main steam isolation valve leakage control system release) to the containment leakage and ESF leakage following a LOCA. This should not be construed as altering the staff recommendations in Section D of Regulatory Guide 1.96 (Rev. 1, June 1976) regarding MSIV leakage-control systems. Other DBAs should be reviewed to determine whether they might constitute a more-severe control-room hazard than the LOCA.

In addition to the accident-analysis results, which should either identify the possible need for control-room modifications or provide assurance that the habitability systems will operate under all postulated conditions to permit the control-room operators to remain in the control room to take appropriate actions required by General Design Criterion 19, the licensee should submit sufficient information needed for an independent evaluation of the adequacy of the habitability systems. Attachment 1 of NUREG-0737, item III.D.3.4 lists the information that should be provided along with the licensee's evaluation.

18.1.71.1.3 Documentation and Implementation

Applicants for operating licenses shall submit their responses prior to issuance of a full-power license. Modifications needed for compliance with the control-room habitability requirements specified in this letter should be identified, and a schedule for completion of the modifications should be provided. Implementation of such modifications should be started without awaiting the results of the staff review. Additional needed modifications, if any, identified by the staff during its review will be specified to licensees.

18.1.71.2 Interpretation

None required.

18.1.71.3 Statement of Response

The control room habitability system design includes protection of the control room from radioactive. Subsection 6.4 provides a description of this system and compliance to habitability requirements. Potential hazards from near by facilities are discussed and evaluated in Subsection 2.2. References for the information required for the NRC control room habitability evaluation are provided in Table 18.1-17.

18.1.72 References

18.1-1 Letter, D. G. Eisenhut (NRC) to S. T. Rogers (BWR Owners' Group), regarding Emergency Procedure Guidelines, October 21, 1980.

18.1-2 U.S. Nuclear Regulatory Commission, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations," USNRC Report NUREG-0578, July 1979, Recommendation 2.1.6b.

18.1-3 U.S. Nuclear Regulatory Commission, "NRC Action Plan Developed as a Result of the TMI-2 Accident," USNRC-0660, Vols. 1 and 2, May 1980, Section II.B.2.

18.1-4 Letter from D. G. Eisenhut (NRC) to All Licensees of Operating Plants and Applicants for Operating Licenses and Holders of Construction Permits, Subject: Preliminary Clarification of TMI Action Plan Requirements, dated September 5, 1980.

18.1-5 U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements," USNRC Report NUREG-0737, November, 1980, Item II.B.2.

18.1-6 U.S. Nuclear Regulatory Commission, IE Bulletin No. 79-01B, "Environmental Qualification of Class IE Equipment," January 14, 1980.

18.1-7 U.S. Nuclear Regulatory Commission, "Interim Staff Position on Environmental Qualification," Report NUREG-0588, December 1979.

18.1-8 USNRC Standard Review Plan 6.4, "Habitability Systems," Revision 1.

18.1-9 USNRC Regulatory Guide 1.3, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Boiling Water Reactors," Revision 2, June 1974.

18.1-10 USNRC Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a Loss-of-Coolant Accident," Revision 2, November 1978.

18.1-11 USNRC Regulatory Guide 1.89, "Qualification of Class IE Equipment for Nuclear Power Plants," November 1974.

18.1-12 Code of Federal Regulations, 10CFR Part 50, Appendix A, GDC 19, Revised as of January 1, 1980.

18.1-13 C. Michael Lederer, et al., Table of Isotopes, Lawrence Radiation Laboratory, University of California, March 1968.

18.1-14 D. S. Duncan and A. B. Spear, GRACE I - An IBM 704-709 Program Design for Computing Gamma Ray Attenuation and Heating in Reactor Shields, Atomics International, (June 1959).

18.1-15 D. S. Duncan and A. B. Spear, GRACE II - An IBM 709 Program for Computing Gamma Ray Attenuation and Heating in Cylindrical and Spherical Geometries, Atomics International, November 1959.

18.1-16 Memorandum of Telephone Conversation, S. Ford of LIS to N. Anderson of NRC's Lessons Learned Task Force, Subject: TMI Requirements at SHNPP, April 9, 1980.

18.1-17 USNRC Regional Meeting Minutes, Region I, Subject: TMI Review Requirements at SHNPP, April 9, 1980.

18.1-18 USNRC Regional Meeting Minutes, Region IV and V, Subject: TMI Review Requirements, 9/26/79.

TABLE 18.1-1

INTERIM REQUIRED SHIFT STAFFING

Operating Status	One Unit, One Control Room	Two Units One Control Room	Two Units Two Control Rooms	Three Units Two Control Rooms
One Unit Operating*	1 SS (SRO) 1 SRO 2 RO 2 AO	1 SS (SRO) 1 SRO 3 RO 3 AO	1 SS (SRO) 1 SRO 3 RO 3 AO	1 SS (SRO) 1 SRO 4 RO 4 AO
Two Units Operating*	NA	1 SS (SRO) 1 SRO 3 RO 3 AO	1 SS (SRO) 2 SRO 4 RO 4 AO	1 SS (SRO) 2 SRO) Only 1 SRO & 4 ROs required 5 RO) if both units are operated) from one control room 5 AO
All Units Operating*	NA	1 SS (SRO) 1 SRO 3 RO 3 AO	1 SS (SRO) 2 SRO 4 RO 4 AO	1 SS (SRO) 2 SRO 5 RO 5 AO
All Units Shut Down	1 SS (SRO) 1 RO 1 AO	1 SS (SRO) 2 RO 3 AO	1 SS (SRO) 2 RO 3 AO	1 SS (SRO) 3 RO 5 AO

SS - shift supervisor
SRO - licensed senior reactor operator
RO - licensed reactor operator
AO - auxiliary operator

NOTE: (1) In order to operate or supervise the operation of more than one unit, an operator (SRO or RO) must hold an appropriate, current license for each such unit.

(2) In addition to the staffing requirements indicated in the table, a licensed senior operator will be required to directly supervise any core alteration activity.

(3) See item I.A.1.1 for shift technical advisor requirements.

* Modes 1 through 3.

TABLE 18.1-2

INITIAL CORE ISOTOPIC INVENTORY[1]

Isotope	Activity in Core Curies	Isotope	Activity in Core (Curies)
Co-58	5.91E+05[2]	Te-131m	2.15E+07
Co-60	3.19E+05	Te-132	1.54 E+08
Br-84	2.40E+06	I-131	1.07 E+08
Kr-85	1.48E+06	I-132	1.57 E+08
Kr-85m	2.68 E+07	I-133	2.22 E+08
KR-87	5.37 E+07	I-134	2.45 E+08
KR-88	7.45 E+07	I-135	2.11 E+08
Rb-86	2.17 E+05	Xe-133	2.12 E+08
Rb-88	7.64 E+07	Xe-135	7.03 E+07
Sr-89	1.03 E+08	Cs-134	2.30 E+07
Sr-90	1.31 E+07	Cs-136	7.34 E+06
Sr-91	1.31 E+08	Cs-137	1.73 E+07
Sr-92	1.39 E+08	Cs-138	2.05 E+08
Y-90	1.36 E+07	Ba-139	1.95 E+08
Y-91	1.34 E+08	Ba-140	1.96 E+08
Y-92	1.40 E+08	La-140	2.09 E+08
Y-93	1.07 E+08	La-141	1.78 E+08
Zr-95	1.92 E+08	La-142	1.74 E+08
Zr-97	1.90 E+08	Ce-141	1.80 E+08
Nb-95	1.92 E+08	Ce-143	1.67 E+08
Mo-99	2.02 E+08	Ce-144	1.51 E+08
Tc-99m	1.79 E+08	Pr-143	1.61 E+08
Ru-103	1.72 E+08	Nd-147	7.24 E+07
Ru-105	1.19 E+08	Np-239	2.12 E+09
Ru-106	6.85 E+07	Pu-238	4.56 E+05
Rh-105	1.11 E+08	Pu-239	4.83 E+04
Sb-127	9.40 E+06	Pu-240	7.79 E+04
Sb-129	3.47 E+07	Pu-241	1.92 E+07
Te-127	9.32 E+06	Am-241	2.54 E+04
Te-127m	1.59 E+06	Cm-242	6.67 E+06
Te-129	3.29 E+07	Cm-244	3.90 E+05
Te-129m	6.66 E+06		

(1) Based on a reactor core thermal power of 4032 MWt and 39 GWd/MTU.
(2) 5.91E+05 means 5.91×10^5

TABLE 18.1-3

POST ACCIDENT RADIATION ZONE CLASSIFICATION[(1)(2)]

Radiation Zone	Maximum Dose Rate
I	≤15 mR/hr
II	≤100 mR/hr
III	≤500 mR/hr
IV	≤5 R/hr
V	≤50 R/hr
VI	≤500 R/hr
VII	≤5000 R/hr
VIII	>5000 R/hr

Notes:

1. Based on maximum contact dose rate for zones containing radiation sources.

2. Based on maximum field dose rate for zones with radiation fields caused by sources located outside the area.

TABLE 18.1-4

VITAL AREAS

State of Occupancy	Figure	Symbol	Post Accident Radiation Zone	Dose [1] [2] (Rem-TEDE)
Continuous				
Main Control Room	18.1-5	A.1	I	0.11
Technical Support Center	18.1-5	A.2	I	0.11
Alternate Operations Support Center in Control Structure	18.1-5	A.3	I	0.80
Alternate Security Control Center (ASCC) - North Gate House	18.1-1	12	I	0.03[3]
Security Control Center	18.1-1	19	I	0.03[3]
Operations Support Center (located in the South Admin Bldg)	18.1-1	15	I	0.03[3]
Security Staging Areas	NA	NA	I	0.88[4]
As Required				
Post Accident Sampling				
1) Radiation Chemistry Lab	18.1-3	B.1	II	0.003[5]
2) Post Accident Vent Sample Station Whole Body Extremity (Hand Leg)	18.1-5	B.2	III	0.002 0.004
Mission to Align Emergency Service Water System to Spent Fuel Pool – (Valve Actuation)	18.1-3	B.3	VIII	3.61[6]

Notes:

(1) Dose is based on contained radiation sources only.

(2) Dose is based on Alternative Source Term for the DBA LOCA.

(3) Dose is based on one year occupancy at the South Administration Building which bounds the doses at the North Gate House and Security Control Center

(4) Representative heightened security locations with dose conservatively based on an assumed minimum distance of 50 ft from contained radiation sources in the reactor building

(5) Dose is based on AST contained radiation source term at 2 hours post LOCA for 30 minutes occupancy

(6) Limiting mission dose involves ingress into Unit 1 reactor building at elevation 670 ft to tie-in ESW system (via actuation of valves 1-53-500 and 1-53-501) and egress with a total exposure duration of approximately 1.5 minutes. Radiation zone designation based on contact dose rate with core spray piping.

TABLE 18.1-5

PRINCIPLE DOSE RATE CONTRIBUTORS IN PLANT AREAS

Structure	Area	Dominant System (Source)
1) Reactor Building Elev. 645'-0" to 670'-0"	 Wetwell HPCI RCIC Core Spray Sump Room	 Suppression pool water (C) HPCI (C, D) RCIC (C, D) Core Spray (C) RHR Cooling Mode (B)
Elev. 670'-0" to 683'-0"	Wetwell RHR Access Corridor	Drywell (A) RHR Cooling Mode (B) RCIC (C)
	Truck Port Railroad Port Other Areas	RHR Cooling Mode (B) RHR Cooling Mode (B) Core Spray (C), RCIC (C), HPCI (C)
Elev. 683'-0" to 719'-1"	Drywell Equip. Areas Equip. Removal Areas Core Spray Piping Area	Drywell (A) RHR Cooling Mode (B) RHR Cooling Mode (B) Core Spray (C)
Elev. 719'-1" to 749'-1"	Drywell Main Steam Tunnel NE Equipment Airlock SW Equipment Airlock South Switch Gear Room CRD Hatch	Drywell (A) Core Spray (C) RHR Spray Mode (C) Core Spray (C) RHR Spray Mode (C) RHR Spray Mode (C)
Elev. 749'-1" to 770'-1"	Drywell Penetration Rooms and other Areas	Drywell (A) Core Spray (C), RHR Spray Mode (C)
2) Control Building Elev. 656'-0" to 806'-0"	 All Areas	 Core Spray (C)
Elev. 806'-0" to 818'-0"	All Areas	Standby Gas Treatment Systems

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TABLE 18.1-6

THIS TABLE HAS BEEN DELETED

TABLE 18.1-7

THIS TABLE HAS BEEN DELETED

TABLE 18.1-8

TRAINING CRITERIA FOR MITIGATING CORE DAMAGE

A program is to be developed to insure that all operating personnel are trained in the use of installed plant systems to control or mitigate an accident in which the core is severely damaged. The training program should include the following topics.

A. Incore Instrumentation

1. Use of fixed or movable incore detectors to determine extent of core damage and geometry changes.

2. Methods for calling up (printing) incore data from the plant computer.

B. Vital Instrumentation

1. Instrumentation response in an accident environment; failure sequence (time to failure, method of failure); indication reliability (actual vs. indicated level).

2. Alternative methods of measuring flows, pressures, levels, and temperatures.

   a. Determination of reactor pressure vessel level if all level transmitters fail.

   b. Determination of other reactor coolant system parameters if the primary method of measurement has failed.

C. Primary Chemistry

1. Expected chemistry results with severe core damage; consequences of transferring small quantities of liquid outside containment; importance of using leak tight systems.

2. Expected isotopic breakdown for core damage; for clad damage.

3. Corrosion effects of extended immersion in primary water; time to failure.

D. Radiation Monitoring

1. Response of Process and Area Monitors to severe damages; behavior of detectors when saturated; method for detecting radiation readings by direct measurement at detector output (overranged detector): expected

TABLE 18.1-8 (page 2of2)

accuracy of detectors at differenct locations; use of detectors to determine extent of core damage.

2. Methods of determining dose rate inside containment from measurements taken outside containment.

E. Gas Generation

1. Methods of hydrogen generation during an accident; other sources of gas (Xe, Kr); techniques for venting or disposal of non-condensibles.

2. Hydrogen flammability and explosive limit; sources of oxygen in containment or reactor coolant system.

TABLE 18.1-9

MITIGATING CORE DAMAGE

COURSE OUTLINE

1. Causes and Thresholds of Core Damage
   - A. Power Transients
   - B. Normal Operating Conditions
   - C. Core Uncovery

2. Recognition of Core Damage
   - A. By Instruments Read in the Control Room
   - B. By Chemical Analysis
   - C. By Containment Conditions

3. Procedures Related to Mitigating Core Damage.

TABLE 18.1-10

CONTAINMENT ISOLATION ACTUATION PROVISIONS (12)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-113 REAC BLDG CCW	NE	1.	X-24	HV - 11313 - 11345	AI AI	F,G F,G	NO NO	(6) (6)
	NE	1.	X-23	HV - 11314 HV - 11346	AI AI	F,G F,G	NO NO	(6) (6)
M-126 Instrument Gas	E	2.	X-41	SV - 12654A - 126154	RM CKV	- -	- -	- -
	E	2.	X-21	SV - 12654B - 126152	RM CKV	- -	- -	- -
	NE	3.	X-19	SV - 12651 - 126074	AI CKV	F,G -	NO -	-
	NE	3.	X-93	SV - 12661 - 126072	AI CKV	B,F -	NO -	-
	NE	3.	X-87	SV - 12605 HV - 12603	AI AI	F,G F,G	NO NO	- -
	NE	3.	X-218	SV - 12671 - 126164	AI CKV	B,F -	NO -	- -
M-139 MSIV LEAKAGE CONTROL SYSTEM	-	-	-	-	-	-	-	(3)

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-141 NUCLEAR BOILER	NE	4.	X-7A (B,C,D)	B21 -1F028A (B,C,D) - 1F022A (B,C,D)	AI AI	(a) (a)	NO NO	(4)(11) (4)(11)
	NE	4.	X-8	B21 - 1F016 - 1F019	AI AI	(a) (a)	NO NO	(4) (4)
	E	5.	X-9A[gp1]	 B21 - 1F032A B21 - 1F010A 141818A	CK RM CK CK	- - - -	- - - -	- - - -
	E	5.	X-9B	 B21 - 1F032B - 1F010B 141818B	CK RM CK CK	- - - -	- - - -	- - - -
	NE	30.	X-35A, C,D,E,F	J004 J004	- -	A,F -	NO -	- -
M-143 REACTOR RECIRC	NE	8.	X-60B	B31 - 1F019 - 1F020	AI AI	B,C B,C	NO NO	(5)(11) (5)(11)
	NE	29.	N-60A	B31 - 1F013A - 1F017A	CK KFC	- -	- -	- -
	NE	29.	X-31B	B31 - 1F013B - 1F017B	CK XFC	- -	- -	- -
M-144 RWCU	NE	7A	X-14	G33 - 1F001 - 1F004	AI AI	(C) (C)	NO NO	- -
M-141 NUCLEAR BOILER	E	7B	X-9A/B	HV-14182A/B 141F039A/B	RM CK	- -	- -	 -

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-148 STANDBY LIQUID CONTROL	E	9.	X-42	C41 - 1F007 - 1F006	CK RM	- -	- -	- -
M-149 RCIC	E	6.	X-9A	E51 - 1F013	AC	-	No	-
	E	6.	X-10	E51 - 1F088 - 1F007 - 1F008	AI AI AI	(K) (K) (K)	YES YES YES	(11) - -
	E	6.	X-216	E51 - 1F019 - 1F021	AC CK	- -	N/A -	- -
	E	6.	X-245	E51 - 1F084 - 1F062	AI AI	F,K,B F,K,B	N/A N/A	- -
	E	6.	X-215	E51 - 1F059 - 1F040	RM CK	- -	- -	- -
	E	6.	X-217	E51 - 1F060 - 1F028	RM CK	- -	- -	- -
	E	6.	X-214	E51 - 1F031	RM	-	-	-
M-151 RHR	NE	10.	X-17	E11 - 1F023 - 1F022	AI AI	(d) (d)	NO NO	- -
	E	11.	X-39A	E11 - 1F016A	AC	F,G	(9)	-
	E	12.	X-13A	E11 - 1F015A - 1F050A - 1F122A	AC AC AC	- - -	NO NO NO	- (11) (11)
	E	11.	X-205A	E11 - 1F028A	AC	F,G	(9)	-
	NE	13.	X-205A	E11 - 1F011A	AI	F,G	NO	-
	E	13.	X-204A	E11 - 1F028A	AC	F,G	(9)	-
	NE	13.	X-204A	E11 - 1F011A	AI	F,G	NO	-

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-151 RHR	E	14.	X-226A	E11 - 1F007A	AC	-	N/A	-
	E	15.	X-246A	E11 - 15106A - 1F103A	PSV RM	- -	- -	-
	E	15.	X-246B	E11 - 15106B - 1F103B	PSV RM	- - -	- - -	- -
	E	16.	X-203A	E11 - 1F004A	RM	-	-	-
	E	16.	X-203C	E11 - 1F004C	RM	-	-	-
	E	11.	X-39B	E11 - 1F016B	AC	F,G	(9)	-
	E	12.	X-13B	E11 - 1F015B - 1F050B - 1F122B	AC AC AC	- - -	NO NO NO	- (11) (11)
	E	12.	X-12	E11 - 1F008 - 1F009 - 1F126	AI AI PSV	(b) (b) -	NO NO -	- - -
	E NE	11.	X-205B	E11 - 1F028B - 1F011B	AC AI	F,G F,G	(9) NO	- -
	E NE	13.	X-204B	E11 - 1F028B E11 - 1F011B	AC AI	F,G F,G	(9) NO	- -
	E	14.	X-226B	E11 - 1F007B	AC	-	N/A	-
	E	16.	X-203D	E11 - 1F004D	RM	-	-	-
	E	16.	X-203B	E11 - 1F004B	RM	-	-	-

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-152 CORE SPRAY	E	17.	X-16A	E21 - 1F005A - 1F006A - 1F037A	AC RM RM	- - -	(10) - -	- (11) (11)
	E	17.	X-16B	E21 - 1F005B - 1F006B - 1F037B	AC RM RM	- - -	(10) - -	- (11) (11)
	NE	18.	X-207A	E21 - 1F015A	AC	F,G	(10)	-
	NE	18.	X-207B	E21 - 1F015B	AC	F,G	(10)	-
	E	19.	X-208A	E21 - 1F031A	AC	-	N/A	-
	E	19.	X-208B	E21 - 1F031B	AC	-	N/A	-
	E	20.	X-206A	E21 - 1F001A	RM	-	-	-
	E	20.	X-206B	E21 - 1F001B	RM	-	-	-
M-155 HPCI	E	21.	X-11	E41 - 1F002 - 1F003 - 1F100	AI AI AI	(1) (1) (1)	YES YES YES	- - (11)
	E	22.	X-211	E41 - 1F012 - 1F046	AC CK	- -	N/A -	- -
	E	21.	X-244	E41 - 1F079 - 1F075	AI AI	F,LB F,LB	N/A N/A	- -
	E	21.	X-210	E41 - 1F066 - 1F049	RM CK	- -	- -	- -
	E	23.	X-209	E41 - 1F042	AI	(1)	NO	-
	E	5.	X-9B	E41 - 1F006	AC	-	(10)	-

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-157 CONTMT ATMOS CONTROL	NE	24.	X-26	HV - 15711 - 15713 - 15714	AI AI AI	B,F,R B,F,R B,F,R	NO NO NO	(7) (7) (7)
	E	25.	X-60A	SV - 15740A - 15742A	AI AI	B,F B,F	NO NO	(8) (8)
	E	25.	X-60A	SV - 15750A - 15752A	AI AI	B,F B,F	NO NO	(8) (8)
	NE	24.	X-202	HV - 15703 - 15704 - 15705	AI AI AI	B,F,R B,F,R B,F,R	NO NO NO	(7) (7) (7)
	E	25.	X-221A	SV - 15780A - 15782A	AI AI	B,F B,F	NO NO	(8) (8)
	E	25.	X-238A	SV - 15736A - 15734A	AI AI	B,F B,F	NO NO	(8) (8)
	E	25.	X-80C	SV - 15740B - 15742B	AI AI	B,F B,F	NO NO	(8) (8)
	E	25.	X-80C	SV - 15750B - 15752B	AI AI	B,F B,F	NO NO	(8) (8)
	E	25.	X-80C	SV - 15776B - 15774B	AI AI	B,F B,F	NO NO	(8),(13) (8)
	NE	24.	X-25	HV - 15722 - 15723 - 15721 - 15724	AI AI AI AI	B,F,R B,F,R B,F,R B,F,R	NO NO NO NO	- - - -
	NE	24.	X-201A	HV - 15725 - 15724 - 15721 - 15723	AI AI AI AI	B,F,R B,F,R B,F,R B,F,R	NO NO NO NO	- - - -

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-157 (con.'t)	E	25.	X-238B	SV - 15734B - 15736B	AI AI	B,F B,F	NO NO	(8) (8),(13)
	E	25.	X-233	SV - 15780B - 15782B	AI AI	B,F B,F	NO NO	(8) (8)
M-157 CONTMT ATMOS CONTROL	E	25.	X-88B	SV - 15776A SV - 15774A	AI AI	B,F B,F	NO NO	(8) (8)
	NE	24.	X-220B	SV - 25737 - 25738	AI AI	B,F,R B,F,R	NO NO	(U2) (U2)
	NE	26.	X-243	HV - 15766 - 15768	AI AI	B,F B,F	NO NO	- -
	NE	31	X-88A	SV - 15767 SV - 15789	AI AI	B,F,R B,F,R	NO NO	(7) (7)
	NE	31	X-220B	SV - 15737 SV - 15738	AI AI	B,F,R B,F,R	NO NO	(7) (7)
M-161 LIQUID RADWASTE CONTROL	NE	27.	X-72B	HV - 16108A1 - 16108A2	AI AI	B,F B,F	NO NO	(11) (11)
	NE	27.	X-72A	HV - 16116A1 - 16116A2	AI AI	B,F B,F	NO NO	(11) (11)
M-187 REACTOR BLDG CHILLED WATER	NE	1.	X-85B	HV - 18791A2 - 18792B0	AI AI	B,F B,F	NO NO	(11) (11)
	NE	1.	X-85A	HV - 18791A1 - 18792B1	AI AI	B,F B,F	NO NO	(11) (11)
	NE	1.	X-54	HV - 18781B2 HV - 18782A2	AI AI	F,G F,G	NO NO	(11) (11)
	NE	1.	X-53	HV - 18781B1 - 18782A1	AI AI	F,G F,G	NO NO	(11) (11)

TABLE 18.1-10 (Continued)

P&ID SYSTEM	E OR NE	BASIS (1)	PENETR. NO.	VALVE NO.	VALVE ACTUATION	AUTOMATIC ACTUATION SIGNALS (2)	AUTO OPEN ON ISO SET	OTHER REMARKS
M-187 (con.t)	NE	1.	X-86B	HV - 18791B2 - 18792A2	AI AI	B,F B,F	NO NO	(11) (11)
	NE	1.	X-86A	HV - 18791B1 - 18792A1	AI AI	B,F B,F	NO NO	(11) (11)
	NE	1.	X-56	HV - 18781A2 - 18782B2	AI AI	F,G F,G	NO NO	(11) (11)
	NE	1	X-55	HV - 18781A1 - 18782B1	AI AI	F,G F,G	NO NO	(11) (11)

REMARKS	
(1)	Essential or non-essential classification basis codes are described in Table 18.1-11.
(2)	Automatic actuation signal codes are described in Table 18.1-12. Actuation signals not for Primary Containment or for system isolation are not listed. All power-operated isolation valves are capable of remote-manual operation from the Control Room.
(3)	Isolation Valve-Leakage Control System was deleted. The main steam leakage is processed by the Isolated Condenser Treatment Method (Section 6.7).
(4)	Automatic signal for isolation UA can be bypassed (B2-1S25A,B,C,D) when the mode switch is not in Run, turbine stop valves are closed, and RPV pressure is less than the high pressure scram setpoint.
(5)	Reactor recirculation system sample line valves B31-1F019 and 1F020 receive high radiation signals for isolation but since the line does not provide an open path from the containment to the environs, the radiation isolation signal may be considered a diverse signal in accordance with Standard Review Plan 6.2.4. This judgement is based on our definition of an open path as a direct, untreated path to the outside environment.
(6)	Either valve opening (or closing) will energize a common open (close) status light. HS-11314 controls both valves. Typical for HV-11345 and HV-11346.
(7A)	Closes on “LOCA” signal. Valves can be administratively reopened if the high drywell pressure is due to plant heat up or loss of drywell cooler.
(7B)	Reactor Water Clean-up – Not essential during or immediately following an accident. May be important in long term recovery operations. Portions between feedwater line and outermost containment isolation valve is essential for HPCI and RCIC injection.
(8)	Closes on “LOCA” signal but can be reopened after 10 minutes.
(9)	Initiation reset will automatically reopen valve if valve handswitch is in open position.
(10)	Initiation reset will not automatically reopen valve.
(11)	Pneumatic actuated valve.
(12)	Hand valves and instrument sensing line excess flow check valves are listed in Tables 6.1-12 and 6.2-12a.
(13)	Unit 2 valve does not have an “R” signal.
(14)	Unit 2 does not have this valve.

TABLE 18.1-11

Security-Related Information
Text Withheld Under 10 CFR 2.390

TABLE 18.1-11 (Cont'd.)

Security-Related Information
Text Withheld Under 10 CFR 2.390

TABLE 18.1-12

**ACTUATION/ISOLATION SIGNAL CODES
& CORRESPONDING ACTUATING SWITCHES**

Isolation actuation signals are listed and described below. Interlocks and bypasses are identified and described in Sections 7.3.1.1a.2 and 7.3.1.1b.2.

A	Reactor Vessel Water Level - Low Level 3
B	Reactor Vessel Water Level - Low, Low Level 2
C	Main Steam Line Radiation - High
D	Main Steam Line Flow - High
EA	Reactor Building Steam Line Tunnel Temperature - High
EC	Turbine Building Steam Line Tunnel Temperature - High
F	Drywell Pressure - High
G	Reactor Vessel Water Level - Low, Low, Low Level I
I	Standby Liquid Control System Manual Initiation
JA	RWCS Differential Flow - High
JB	RWCS Differential Pressure - High
KA	RCIC Steam Line Pressure - High
KB	RCIC Steam Supply Pressure - Low
KC	RCIC Turbine Exhaust Diaphragm Pressure - High
KD	RCIC Equipment Room Temperature - High
KE	RCIC Equipment Room Temperature - High
KF	RCIC Pipe Routing Area Temperature - High
KG	RCIC Pipe Routing Area Temperature - High
KH	RCIC Emergency Area Cooler Temperature - High
LA	HPCI Steam Line Pressure - High
LB	HPCI Steam Supply Pressure - Low
LC	HPCI Turbine Exhaust Diaphragm Pressure - High

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TABLE 18.1-12

ACTUATION/ISOLATION SIGNAL CODES
& CORRESPONDING ACTUATING SWITCHES

LD	HPCI Equipment Room Temperature - High
LE	HPCI Equipment Room Temperature - High
LF	HPCI Emergency Area Cooler Temperature - High
LG	HPCI Pipe Routing Area Temperature - High
LH	HPCI Pipe Routing Area Temperature - High
MC	RHR System Flow - High
P	Turbine First Stage Pressure - Low
R	SGTS Exhaust Radiation - High
UA	Main Condenser Vacuum - Low
UB	Reactor Vessel Pressure - High
WA	RWCS Area Temperature - High

Isolation Actuation Groupings

(a)	G, C, D, EA, EC, P, UA
(b)	A, MC, UB
(c)	B, JA, JB, WA
(d)	A, F,-MC, UB
(k)	KA, KB, KC, KD, KE, KF, KG, KH
(l)	LA, LB, LC, LD, LE, LF, LG, LH

TABLE 18.1-13
METEOROLOGICAL INFORMATION

Meteorological Information	CR	TSC	EOF	NRC and Emergency Response Organizations
Basic Met. Data (e.g., 1.97 Parameters)	X	X	X	X (NRC)
Full Met. Data (1.23 Parameters)		X	X	X
DCM (for Dose Projections)	X	X	X	X
Class A Model (to Plume Exposure EPZ)	X	X	X	X
Class B Model or Class A Model (to Ingestion EPZ)		X	X	X

f;18.1.5811

TABLE 18.1-14

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TABLE 18.1-15

THIS TABLE HAS BEEN DELETED

TABLE 18.1-16

THIS TABLE HAS BEEN DELETED

TABLE 18.1-17

INFORMATION REQUIRED FOR CONTROL ROOM HABITABILITY EVALUATION

Data	Reference*
1. Control Room Mode of Operation (i.e., pressurization for radiological accident isolation and manual filter recirculation for hazardous chemical release).	6.4.2, 6.4.3
2. Control Room Characteristics:	
a. air volume control room;	6.4.2
b. control room emergency zone (control room critical files, kitchen, washroom, computer room, etc.);	6.4.2
c. control room ventilation system schematic with normal and emergency air flow rates;	Figs. 9.4-1 & 9.4-2
d. infiltration leakage rate;	6.4.2
e. HEPA filter and charcoal adsorber efficiencies;	6.4.3, 6.5.1
f. closest distance between containment and air intake;	Fig. 6.4-2
g. layout of control room air, intakes, containment building, or other chemical storage facility with dimensions;	Fig. 6.4-2
h. control room shielding including radiation streaming from penetrations doors, ducts, stairways, etc.;	12.3.2
i. automatic isolation capability-damper closing time, damper leakage and area;	Table 6.4-1
j. self-contained breathing apparatus availability (number);	EP-AD-013
k. bottled air supply (hours supply);	EP-AD-013
l. emergency food and potable water supply (how many days and how many people);	EP-AD-013
m. control room personnel capacity (normal and emergency); and	6.4.1
n. potassium iodide drug supply.	EP-AD-013
3. On-Site Storage of Hazardous Chemicals:	
a. total amount and size of container; and	PLI-92803
b. closest distance from control room air intake.	PLI-92803
4. Off-Site Manufacturing, Storage or Transportation Facilities of Hazardous Chemicals:	
a. identify facilities within a five-mile radius;	PLA-694
b. distance from control room;	PLA-694
c. quantity of hazardous chemicals in one container; and	railroad car (largest)
d. frequency of hazardous chemical transportation traffic (truck, rail, and barge).	PLA-694
5. Technical Specifications:	
a. Technical Specifications	TS 3.7.3, TS 3.7.4

* All references are in the FSAR unless otherwise noted.

TABLE 18.1-18

POSSIBLE ICC DETECTION DEVICES

Name of Device	Reference Number
Source Range Monitor	1
Intermediate Range Monitor	2
Local Power Range Monitor	3
Traveling Incore Probe	4
Gamma-Neutron Reaction Detector	5
Gamma Attenuation	6
Gamma Void Meter	7
Neutron Modulation Void Meter	8
Core Reactivity Detector	9
Fuel Plenum Tracer	10
Primary System Activity Meter	11
Incore Thermocouples	12
Heater Junction Thermocouples	13
Gamma Thermometers	14
Control Rod Drive Thermocouples	15
Sight Glass	16
Cerenkov Light Detector	17
Wave Guide	18
Vessel Weight	19
Vessel Vibrations	20
Floats	21
Conductivity Probe	22
Capacitance Probe	23
Sonic Reflection	24
Loose Parts Monitor	25
Microwave Probe	26
Mass Balance	27
Differential Expansion Integal Anemometer	28
Delta-P Bubbler	29
Self-Powered Neutron Detector	30
Resistance Temperature Detectors	31
Steam Dome Thermocouples	32
Liquid Level and Void Fraction Detector	33

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RADIATION LEVELS FOR
THE SITE PLAN

FIGURE 18.1-1, Rev 55

AutoCAD: Figure Fsar 18_1_1 dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RADIATION LEVELS FOR THE
SITE PLAN - ELEVATIONS
646'-0", 645'-0" AND 654'-0"

FIGURE 18.1-2, Rev 55

AutoCAD: Figure Fsar 18.1-2.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RADIATION LEVELS
ELEVATIONS 670'-0" AND 676'-0"

FIGURE 18.1-3, Rev 56

AutoCAD: Figure Fsar 18.1-3.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RADIATION LEVELS FOR ELEVATIONS
683'-0", 699'-0", 714'-0" & 716'-3"

FIGURE 18.1-4, Rev 55

AutoCAD: Figure Fsar 18_1_4.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
RADIATION LEVELS FOR ELEVATIONS 719'-1", 729'-0" & 741'-1" FIGURE 18.1-5, Rev 55

AutoCAD: Figure Fsar 18_1_5.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RADIATION LEVEL FOR
ELEVATIONS 749'-1", 754'-0"
762'-0", 771'-0" AND 783'-0"

FIGURE 18.1-6, Rev 56

AutoCAD: Figure Fsar 18.1 6.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
RADIATION LEVEL FOR ELEVATIONS 779'-1", 799'-1" AND 806'-0"
FIGURE 18.1-7, Rev 56

AutoCAD: Figure Fsar 18.1-7.dwg

Security-Related Information
Figure Withheld Under 10 CFR 2.390

FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

RADIATION LEVEL FOR ELEVATIONS
818'-1" AND 872'-4 $\frac{1}{2}$"

FIGURE 18.1-8, Rev 55

AutoCAD: Figure Fsar 18.1-8.dwg

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FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
Figure Deleted FIGURE 18.1-9, Rev. 50

AutoCAD Figure 18_1_9.doc

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SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

Figure Deleted

FIGURE 18.1-10, Rev. 50

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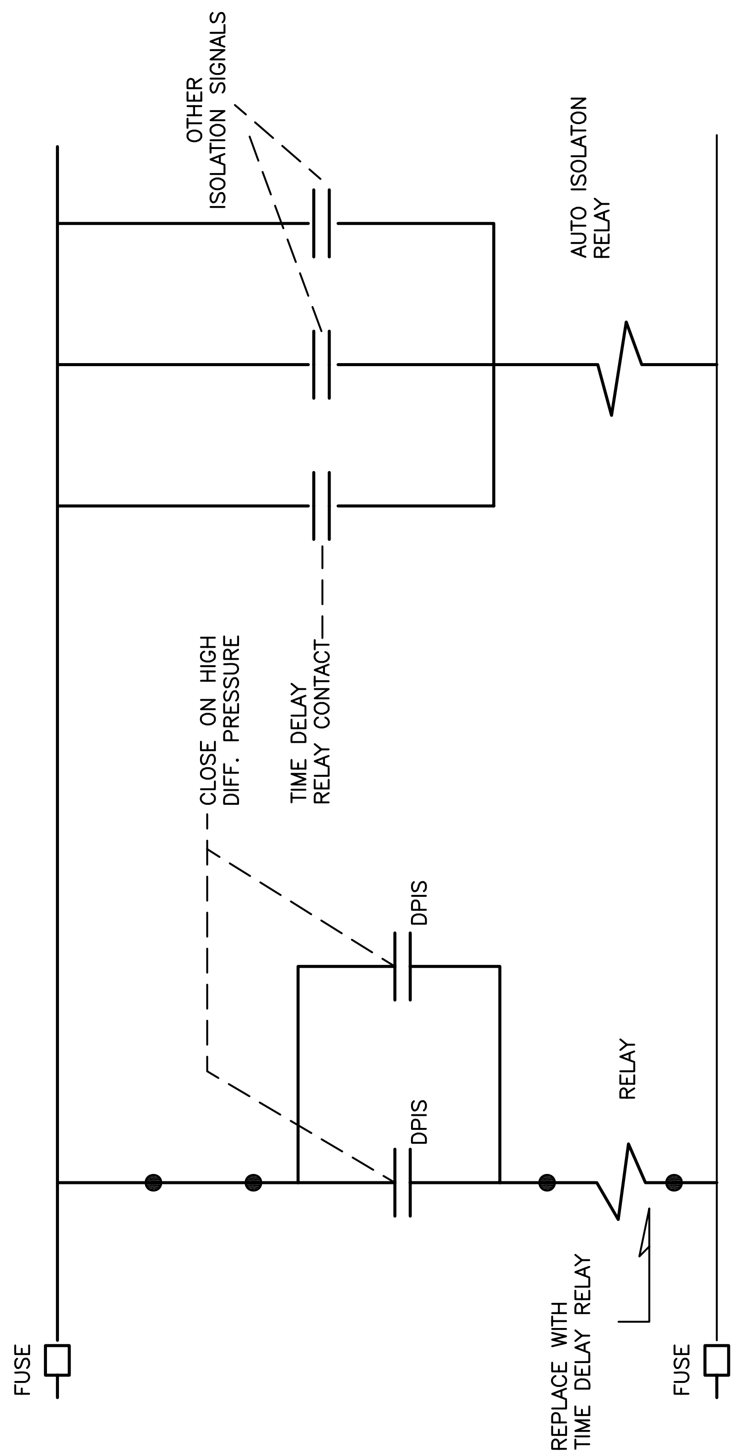
FSAR REV. 65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
Figure Deleted FIGURE 18.1-11, Rev. 50

AutoCAD Figure 18_1_11.doc



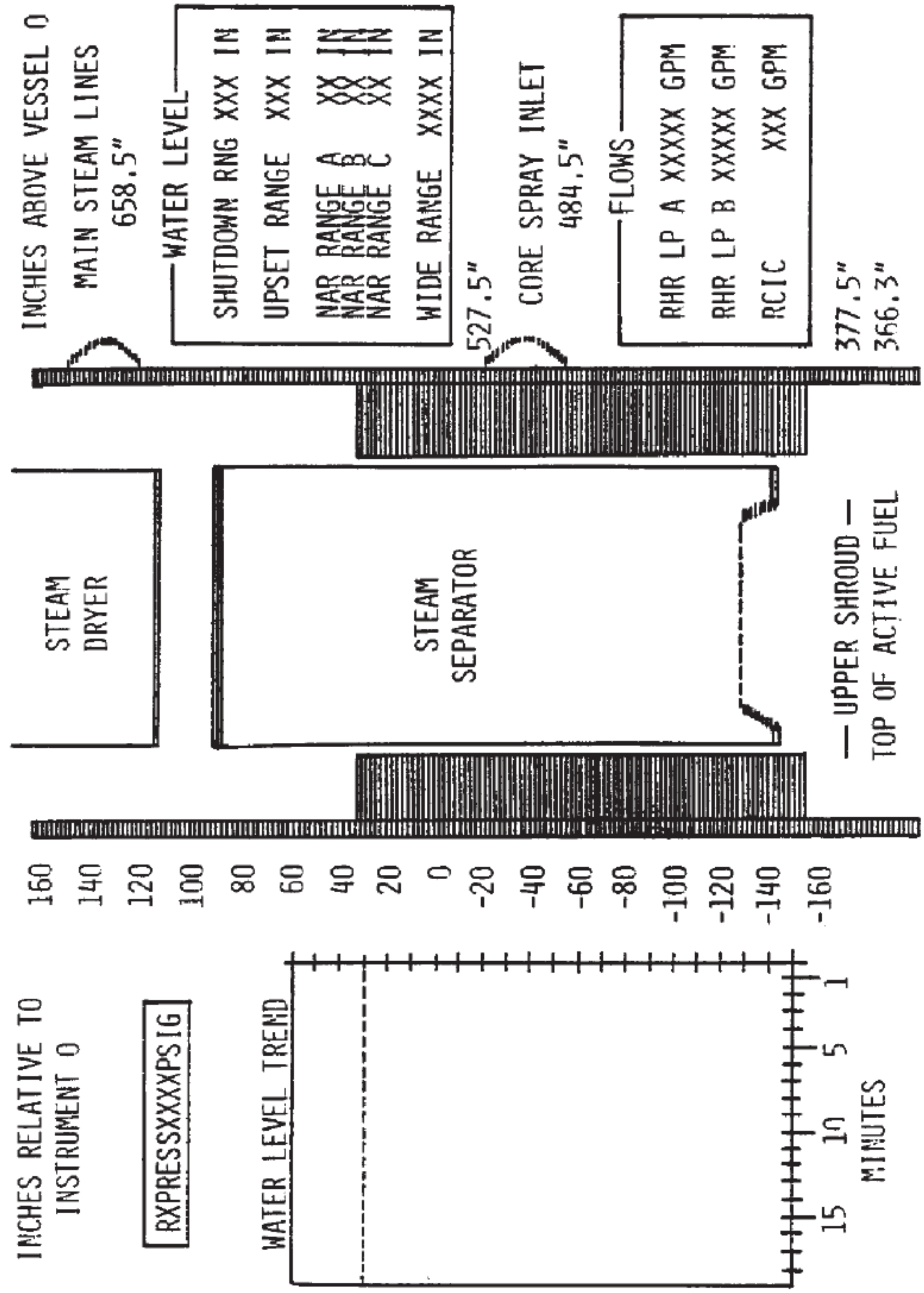
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

TYPICAL HPCI/RCIC
STEAMLINE BREAK
DETECTION LOGIC

FIGURE 18.1-12, Rev 49

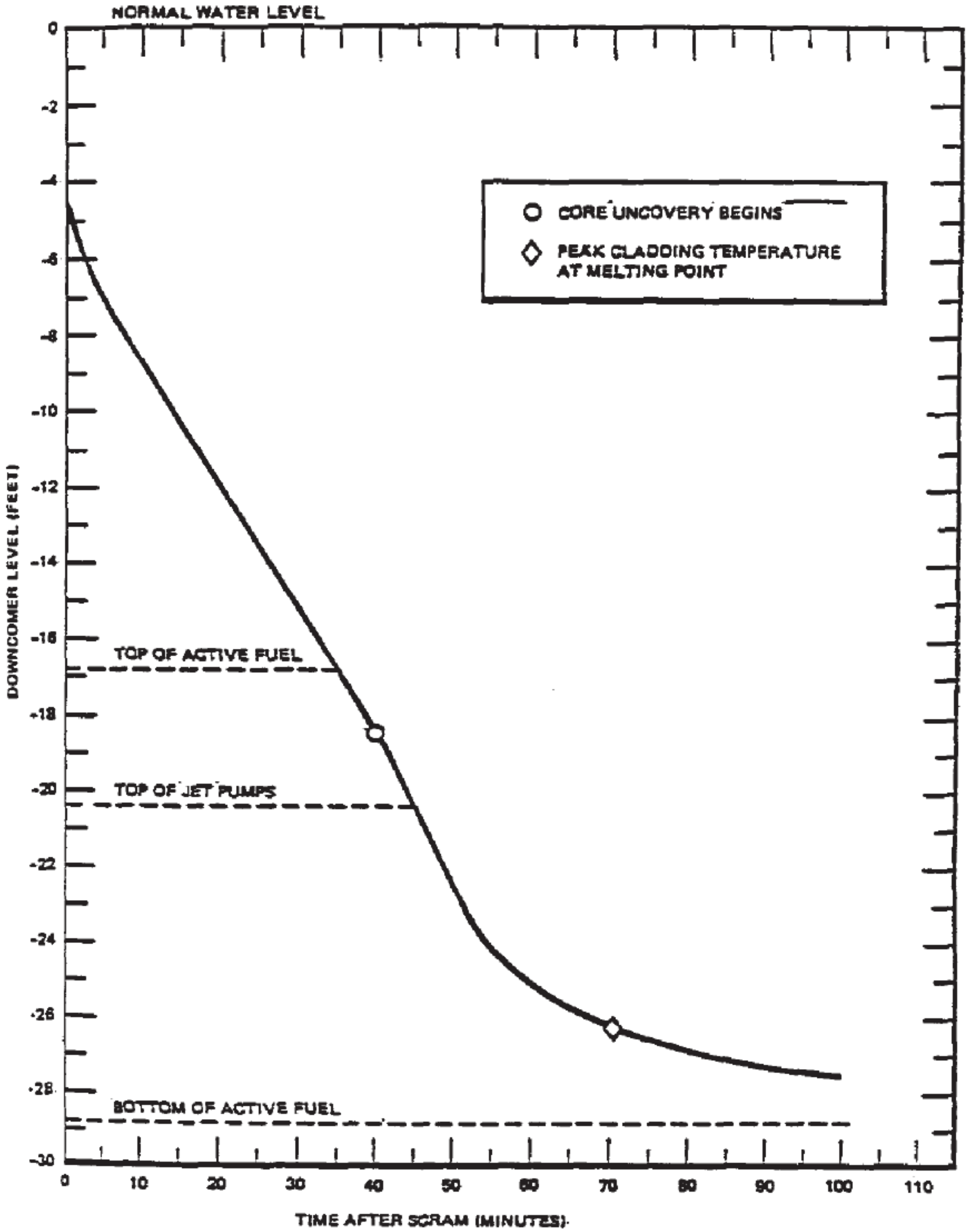
AutoCAD: Figure Fsar 18_1_12.dwg



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION UNITS 1 & 2 FINAL SAFETY ANALYSIS REPORT
TYPICAL REACTOR WATER LEVEL DISPLAY FIGURE 18.1-13, Rev 49

AutoCAD: Figure Fsar 18_1_13.dwg



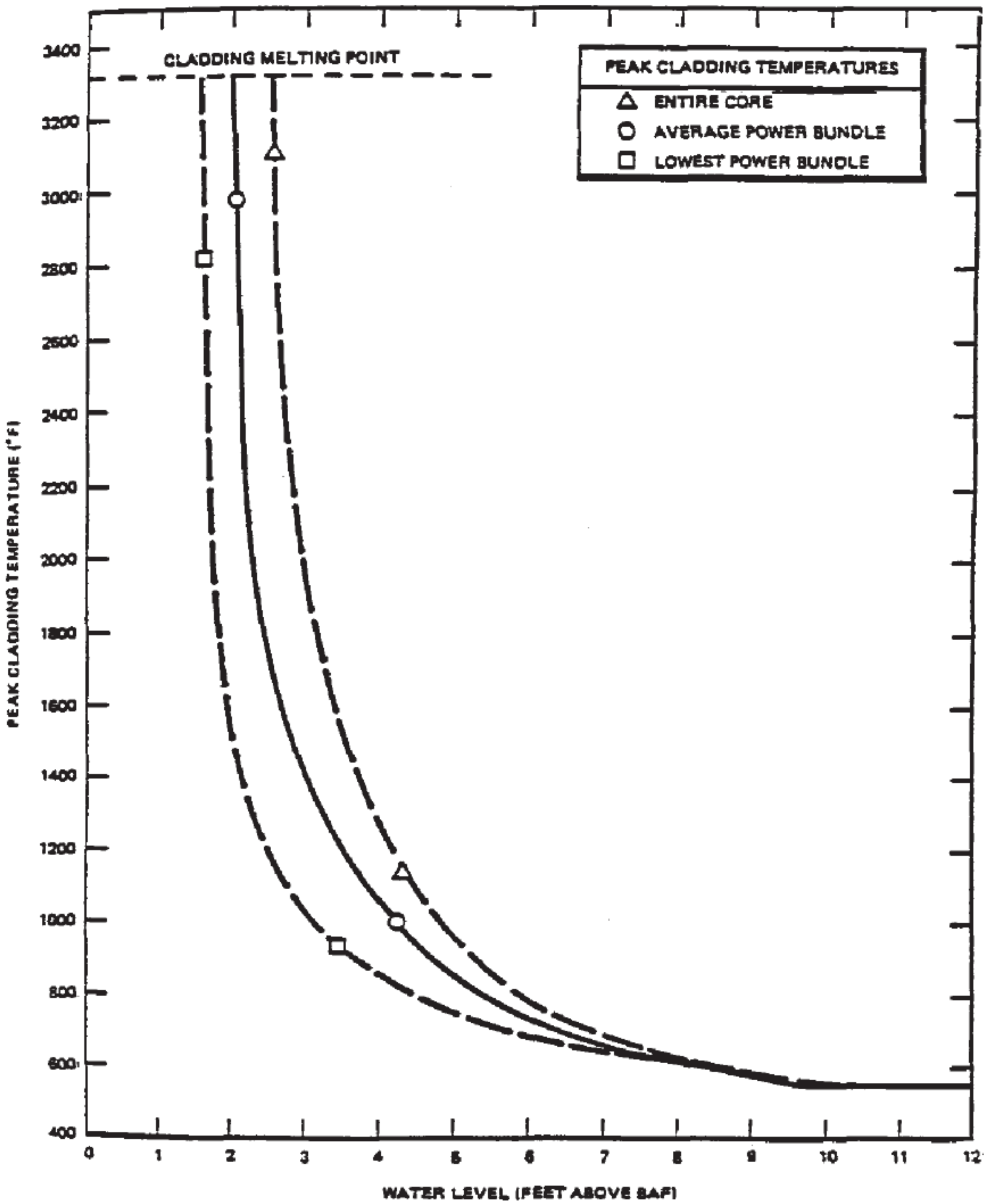
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

DOWNCOMER WATER
LEVEL HISTORY

FIGURE 18.1-14, Rev 49

AutoCAD: Figure Fsar 18_1_14.dwg



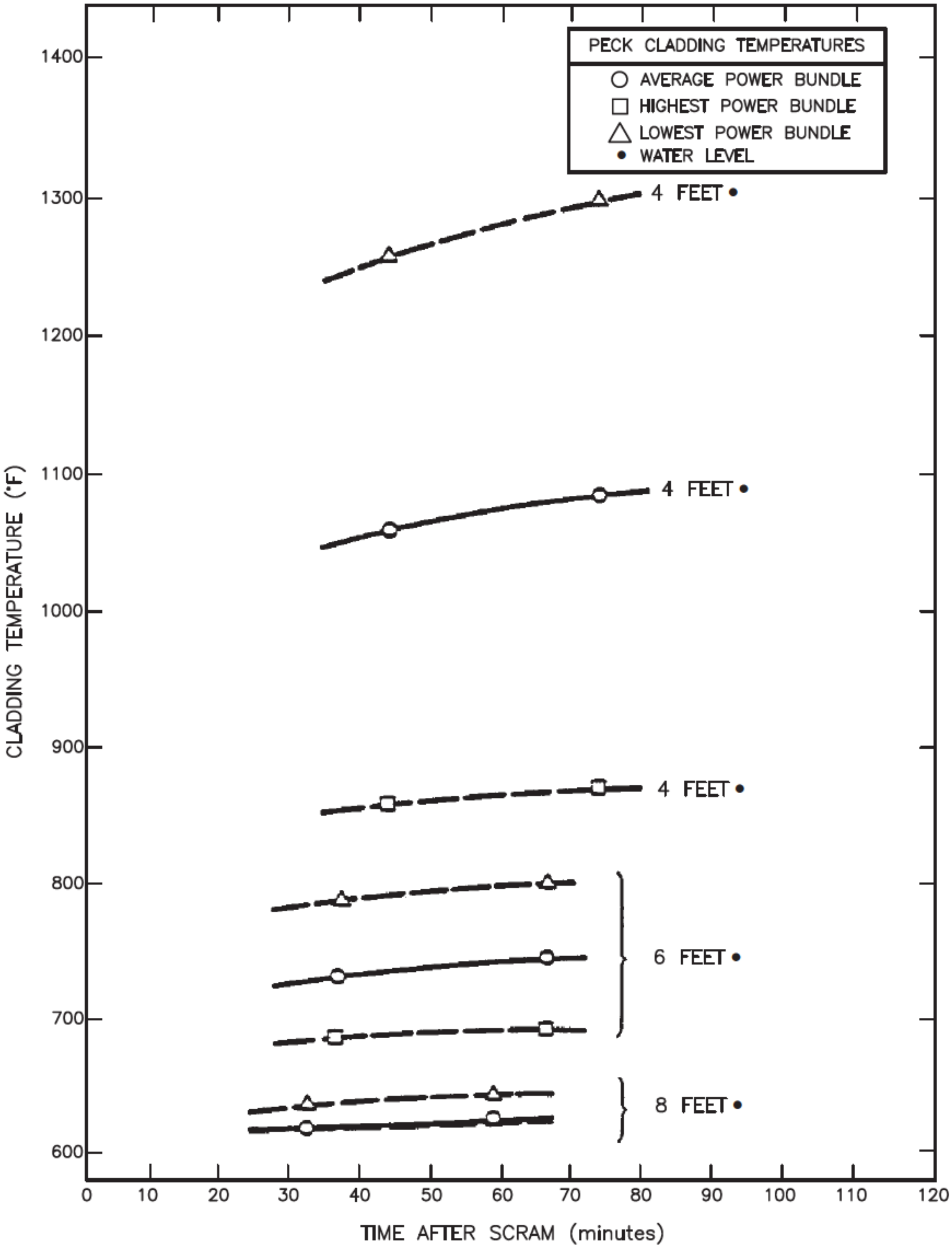
FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

WATER LEVEL AS AN INDICATOR
OF CORE OVERHEATING

FIGURE 18.1-15, Rev 49

AutoCAD: Figure Fsar 18_1_15.dwg



FSAR REV.65

SUSQUEHANNA STEAM ELECTRIC STATION
UNITS 1 & 2
FINAL SAFETY ANALYSIS REPORT

CLADDING TEMPERATURE
SENSITIVITY TO CORE
RECOVERY TIME

FIGURE 18.1-16, Rev 49

AutoCAD: Figure Fsar 18_1_16.dwg

18.2 RESPONSE TO REQUIREMENTS IN NUREG 0694

NUREG-0694 supersedes NUREG 0578. The clarifications given in the Vassallo letter on November 9, 1979 were used in the development of applicable responses.

18.2.1 SHIFT TECHNICAL ADVISOR (I.A.1.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.1 for response.

18.2.2 SHIFT SUPERVISOR ADMINISTRATIVE DUTIES (I.A.1.2)

18.2.2.1 Statement of Requirement

Review the administrative duties of the shift supervisor and delegate functions that detract from or are subordinate to the management responsibility for assuring safe operation of the plant to other personnel not on duty in the control room. This requirement shall be met before fuel load.

18.2.2.2 Interpretation

None required.

18.2.2.3 Statement of Response

PP&L has restructured the operations organization and redefined responsibilities of shift personnel to relieve the shift supervisor of routine administrative duties.

Administrative procedure NDAP-QA-0300, "Conduct of Operations," implements this policy.

The Plant Manager reviews and approves the Shift Supervisor's responsibilities to ensure proper delegation of duties that detract from or are subordinate to the safe operation of the plant.

18.2.3 SHIFT MANNING (I.A.1.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.3 for response.

18.2.4 IMMEDIATE UPGRADING OF OPERATOR AND SENIOR OPERATOR TRAINING AND QUALIFICATION (I.A.2.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.4 for response.

18.2.5 REVISE SCOPE AND CRITERIA FOR LICENSING EXAMINATIONS (I.A.3.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.6 for response.

18.2.6 EVALUATION OF ORGANIZATION AND MANAGEMENT IMPROVEMENTS OF NEAR-TERM OPERATING LICENSE APPLICANTS (I.B.1.2)

18.2.6.1 Statement of Requirement

The licensee organization shall comply with the findings and requirements generated in an interoffice NRC review of licensee organization and management. The review will be based on an NRC document entitled Draft Criteria for Utility Management and Technical Competence. The first draft of this document was dated February 25, 1980, but the document is changing with use and experience in ongoing reviews. These draft criteria address the organization, resources, training, and qualifications of plant staff, and management (both onsite and offsite) for routine operations and the resources and activities (both onsite and offsite) for accident conditions. This requirement shall be met prior to fuel load.

18.2.6.2 Interpretation

None required.

18.2.6.3 Statement of Response

A review of organization and management has been completed in accordance with draft NUREG 0731, "Guidelines for Utility Management Structure and Technical Competence." An NRC audit of the organization was conducted March 2-6, 1981.

18.2.7 SHORT-TERM ACCIDENT ANALYSIS AND PROCEDURE REVISION (I.C.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.8 for response.

18.2.8 SHIFT RELIEF AND TURNOVER PROCEDURES (I.C.2)

18.2.8.1 Statement of Requirement

Revise plant procedures for shift relief and turnover to require signed checklists and logs to assure that the operating staff (including auxiliary operators and maintenance personnel) possess adequate knowledge of critical plant parameter status, system status, availability and alignment. This requirement shall be met prior to fuel load.

18.2.8.2 Interpretation

None required.

18.2.8.3 Statement of Response

Administrative procedures OP-AD-002, "Operations Standards for Error and Event Prevention" and OP-AD-003 “Shift Surveillance Scheduling, Log Sheets, and Turnover Sheets” discuss operations personnel responsibilities at shift turnover and specifically define the shift turnover process.

18.2.9 SHIFT SUPERVISOR RESPONSIBILITIES (I.C.3)

18.2.9.1 Statement of Requirement

Issue a corporate management directive that clearly establishes the command duties of the shift supervisor and emphasizes the primary management responsibility for safe operation of the plant. Revise plant procedures to clearly define the duties, responsibilities and authority of the shift supervisor and the control room operators. This requirement shall be met prior to fuel load.

18.2.9.2 Interpretation

None required.

18.2.9.3 Statement of Response

The Senior Vice President - Chief Nuclear Officer has issued a statement of policy establishing the primary responsibility of the Shift Supervisor for safe operation of the plant under all conditions and establishing authority to direct actions leading to safe operation in the Shift Supervisor. The Senior Vice President - Chief Nuclear Officer shall re-issue this statement of policy on an annual basis.

Administrative Procedure NDAP-QA-0300, "Conduct of Operations," sets forth the plant policy on Shift Supervisor duties.

Training for Shift Supervisors includes plant Administrative Procedures, and will encompass NDAP-QA-0300.

18.2.10 CONTROL ROOM ACCESS (I.C.4)

18.2.10.1 Statement of Requirement

Revise plant procedures to limit access to the control room to those individuals responsible for the direct operation of the plant, technical advisors, specified NRC personnel, and to establish a clear line of authority, responsibility, and succession in the control room. This requirement shall be met prior to fuel load.

18.2.10.2 Interpretation

None required.

18.2.10.3 Statement of Response

Administrative procedure OP-AD-002, Operations Standards for Error and Event Prevention provides the authority and instructions for control room access control.

18.2.11 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO PLANT STAFF (I.C.5)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.12 for response.

18.2.12 NSSS VENDOR REVIEW OF PROCEDURES (I.C.7)

18.2.12.1 Statement of Requirement

Obtain nuclear steam supply system vendor review of low-power testing procedures to further verify their adequacy. This requirement shall be met prior to fuel load.

Obtain NSSS vendor review of power-ascension test and emergency procedures to further verify their adequacy. This requirement must be met before issuance of a full-power license.

18.2.12.2 Interpretation

None required.

18.2.12.3 Statement of Response

The General Electric Company, through its site startup organization, has reviewed all startup tests associated with NSSS systems and will review all Emergency Operating procedures that were submitted to NRC in response to item I.C.8 (see Subsection 18.2.13). The startup tests encompass the low power testing and the power ascension testing phases.

18.2.13 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES NEAR-TERM OPERATING LICENSE APPLICANTS (I.C.8)

18.2.13.1 Statement of Requirement

Correct emergency procedures, as necessary, based on the NRC audit of selected plant emergency operating procedures (e.g., small-break LOCA, loss of feedwater, restart of engineered safety features following a loss of AC power or, steam-line break).

18.2.13.2 Interpretation

None required.

18.2.13.3 Statement of Response

Emergency procedures based on those quidelines have been developed and are currently in trial use on the Susquehanna SES Simulator. These procedures have been reviewed by the NRC. Final versions which incorporated NRC comments were submitted in a letter from N. W. Curtis to B. J. Youngblood on May 15, 1981 (PLA-791).

18.2.14 CONTROL ROOM DESIGN (I.D.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.16 for response.

18.2.15 TRAINING DURING LOW POWER TESTING (I.G.1)

18.2.15.1 Statement of Requirement

Define and commit to a special low-power testing program approved by NRC to be conducted at power levels no greater than 5 percent for the purposes of providing meaningful technical information beyond that obtained in the normal startup test program and to provide supplemental training. This requirement shall be met before fuel load.

Supplement operator training by completing the special low-power test program. Tests may be observed by other shifts or repeated on other shifts to provide training to the operators. This requirement shall be met before issuance of a full-power license.

18.2.15.2 Interpretation

None required.

18.2.15.3 Statement of Response

The BWR Owners' Group has prepared a generic response to this requirement. This was transmitted to D. G. Eisenhut by a letter from D. B. Waters on February 4, 1981. PP&L concurs with this response. This generic approach outlines an extensive testing program designed to contribute to and provide for extensive training opportunities during the start-up program.
The objectives of this program are to provide:

1. A plant that has been thoroughly tested.

2. An operating staff that has received the maximum experience and in-plant training to safely operate it.

3. Plant procedures that have been reviewed and revised to provide the staff with proven directions and controls.

Susquehanna's Operator Training Program has been in progress since 1977 and is completing the final phases of training at this time. This program utilizes the Susquehanna Simulator

located at the plant site and provides the operators with extensive training prior to actual operations in the plant itself. The Simulator is also used for procedure development and check out.

The Operator Training Program that is being developed for the Preoperational and Low Power Testing Program incorporates and builds on the extensive training already completed by the operations section. It will include the recommendation presented in the BWR Owners' Group position but goes beyond those recommendations by maximizing the use of the Susquehanna Simulator in preparing the operators for the start-up tests to be performed.

The objective of the Operator Training Program is to provide each operator with the maximum learning experience during the start-up phase. In order to achieve this objective, a comprehensive training program is being developed that utilizes the many training opportunities that are available during this period and ensures actual testing. This program covers the period from Preoperational/Acceptance Testing through the Power Test Program on Unit I. To support this amount of training the operations section which is staffed for six sections has reorganized into four sections. This reorganization provided the benefit of allowing more operators off shift to attend formal training as well as provide more operating experience for each shift team. Every effort is being made to keep the shifts intact and provide training that promotes the "Shift Team" concept.

The training program being developed covers the areas of activities listed below but recognizes the overlap that exists between some of the areas.

I. Preoperational/Acceptance Testing

II. Cold Functional Testing

III. Hot Functional Testing

IV. Start-up Tests

V. Additional Testing

Each area of testing has activities that lend itself to operator training. The major ones are outlined in Table 18.2-1. The training program provides a vehicle to identify activities that have a significant benefit for training, documents this training, and ensures that all shift crews receive equal experience opportunities. The program also attempts to schedule repeats of certain evolutions that are considered critical and cannot be routinely performed at a later time. The training program will identify areas of testing/training that while not required by start-up program would have additional training benefit. This testing/training could then be scheduled into the testing program as additional testing.

Finally this program will develop the basis for the In-Plant Drill Program. This comprehensive approach to testing/training more than adequately satisfies the requirements of NUREG 0737.

On June 15, 1982 (PLA-1136) PP&L submitted a station blackout Safety Analysis which demonstrates that a station blackout test unnecessarily jeopardizes the plant and the public. Therefore, no station blackout test will be performed on Susquehanna SES Units 1 and 2. PP&L has completed additional testing per the BWROG recommendations during the Startup

Test Program for Unit 1 which satisfies the intent of this requirement. As stated in Generic Letter 83-24, this additional testing along with the safety analysis will satisfy Item I.G.1.

18.2.16 REACTOR COOLANT SYSTEM VENTS (II.B.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.19 for response.

18.2.17 PLANT SHIELDING (II.B.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.20 for response.

18.2.18 POST-ACCIDENT SAMPLING (II.B.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.21 for response.

18.2.19 TRAINING FOR MITIGATING CORE DAMAGE (II.B.4)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.22 for response.

18.2.20 RELIEF AND SAFETY VALVE TEST REQUIREMENTS (II.D.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.23 for response.

18.2.21 RELIEF AND SAFETY VALVE POSITION INDICATION (II.D.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.24 for response.

18.2.22 CONTAINMENT ISOLATION DEPENDABILITY (II.E.4.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.29 for response.

18.2.23 ADDITIONAL ACCIDENT MONITORING INSTRUMENTATION (II.F.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.30 for response.

18.2.24 INADEQUATE CORE COOLING INSTRUMENTS (II.F.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.31 for response.

18.2.25 ASSURANCE OF PROPER ESF FUNCTIONING (II.K.1.5)

18.2.25.1 Statement of Requirement

Review all valve positions, positioning requirements, positive controls and related test and maintenance procedures to assure proper ESF functioning. This requirement shall be met by fuel load.

18.2.25.2 Interpretation

None required.

18.2.25.3 Statement of Response

Operating and surveillance procedures are currently being developed. Writing the procedures to reflect ESF requirement is a key objective of procedure originators. Additionally, these procedures will receive a review (independent of the originator) to provide further assurance that the procedure is technically correct and provides for accomplishment of procedural objectives (including maintenance of proper safety function).

18.2.26 SAFETY RELATED SYSTEM OPERABILITY STATUS (II.K.1.10)

18.2.26.1 Statement of Requirement

Review and modify, as required, procedures for removing safety-related systems from service (and restoring to service) to assure operability status is known. This requirement shall be met by fuel load.

18.2.26.2 Interpretation

None required.

18.2.26.3 Statement of Response

Surveillance testing will be controlled by administrative procedure NDAP-QA-0722. This procedure requires surveillance implementing procedures contain a review of redundant component operability prior to removing the system to be tested from service, (if such removal is required by the test), a review of proper system status prior to return of the tested system to service, and provide for notification to Operations of the need for system status changes.

Administrative Procedure NDAP-QA-0302, "System Status and Equipment Control," (see Subsection 18.1.13.3) establishes control of system status as an operations responsibility and will provide the same reviews described above during normal operations and maintenance activities. Maintenance procedures will only cover activities while systems and components are removed from service, the Operations section will actually accomplish changes in system status as controlled by the described Instruction.

18.2.27 TRIP PRESSURIZER LOW-LEVEL COINCIDENT SIGNAL BISTABLES (II.K.1.17)

This requirement is not applicable to Susquehanna SES.

18.2.28 OPERATOR TRAINING FOR PROMPT MANUAL REACTOR TRIP (II.K.1.20)

This requirement is not applicable to Susquehanna SES.

18.2.29 AUTOMATIC SAFETY GRADE ANTICIPATORY TRIP (II.K.1.21)

This requirement is not applicable to Susquehanna SES.

18.2.30 AUXILIARY HEAT REMOVAL SYSTEMS OPERATING PROCEDURES (II.K.1.22)

18.2.30.1 Statement of Requirement

Describe the automatic and manual actions necessary for proper functioning of the auxiliary heat removal systems that are used when the main feedwater system is not operable. This requirement shall be met by fuel load.

18.2.30.2 Interpretation

None required.

18.2.30.3 Statement of Response

A generic response to this requirement was provided by General Electric in NEDO-24708, "Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," (August, 1979) and supplement 1. A plant specific description is provided below.

If the main feedwater system is not operable, a reactor scram will automatically initiate when reactor water level falls to Level 3 (540.5 inches above vessel bottom or 178.2 inches above the top of the active fuel). The operator can then remote manually initiate the reactor core isolation cooling system from the main control room, or the system will be automatically initiated when reactor water level decreases to Level 2 (489.5 inches above vessel bottom or 127.2 inches above the top of the active fuel) due to boil-off. At this point, the high pressure coolant injection system will also automatically start supplying makeup water to the vessel. These systems will continue automatic injection until the reactor water level reaches Level 8 (581.5 inches above vessel bottom or 219.2 inches above top of the active fuel), at which time the high pressure coolant injection turbine and the reactor core isolation cooling turbine are automatically tripped.

In the non-accident case, the reactor core isolation cooling system is utilized to furnish subsequent makeup water to the reactor pressure vessel. The Reactor core isolation cooling system and the high pressure coolant injection system will restart automatically when the level

falls to Level 2 (The reactor core isolation cooling system is being modified to automatically restart, see subsection 18.1.50). No manual actions are required for these systems to restart. Reactor vessel pressure is regulated by the automatic or remote manual operation of the main steam relief valves which blow down to the suppression pool.

To remove decay heat, assuming that the main condenser is not available, the main steam relief valves can be manually actuated from the control room. Remote manual alignment of the residual heat removal system into the suppression pool cooling mode is then required for suppression pool heat removal. Makeup water to the vessel is still supplied by the reactor core isolation cooling system under manual control.

For the accident case with the reactor pressure vessel at high pressure, the high pressure coolant injection system is utilized to automatically provide the required makeup flow.
No manual operations are required since the high pressure coolant injection system will cycle on and off automatically as water level reaches Level 2 and Level 8, respectively.
If the high pressure coolant injection system fails under these conditions, the operator can manually depressurize the reactor vessel using the automatic depressurization system to permit the low pressure emergency core cooling systems to provide makeup coolant.
Automatic depressurization will occur if all of the following signals are present: high drywell pressure 1.69 psig, Level 3 water Level permissive, Level 1 water level (398.5 inches above vessel bottom or 36.2 inches above the top of the active fuel), pressure in at least one low pressure injection system and the run out of a 120 second timer (set at 105 seconds) which starts with the coincidence of the other four signals.

18.2.31 REACTOR LEVEL INSTRUMENTATION (II.K.1.23)

18.2.31.1 Statement of Requirement

For boiling water reactors, describe all uses and types of reactor vessel level indication for both automatic and manual initiation of safety systems. Describe other instrumentation that might give the operator the same information on plant status. This requirement shall be met before fuel load.

18.2.31.2 Interpretation

None required.

18.2.31.3 Statement of Response

The response to this requirement was provided by General Electric in NEDO-24708, Additional Information Required for NRC Staff Generic Report on Boiling Water Reactors," (August 1979) and Supplement 1.

18.2.32 COMMISSION ORDERS ON BABCOCK AND WILCOX PLANTS (II.K.2)

These requirements are not applicable to Susquehanna SES.

18.2.33 REPORTING REQUIREMENTS FOR SAFETY/RELIEF VALVE FAILURES OR CHALLENGES (II.K.3.3)

18.2.33.1 Statement of Requirement

Assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORVs or safety valves should be documented in the annual report. This requirement shall be met before issuance of a full-power license.

18.2.33.2 Interpretation

Prompt reporting to the NRC consists of notification within 24 hours by telephone with confirmation by telegraph, mailgram or facsimile transmission, followed by a written report within 14 days.

The annual operating report has been supplanted by more detailed Monthly Operating Reports. Documentation required to be included in the annual report will be supplied in Monthly Operating Reports.

18.2.33.3 Statement of Response

Subsection 6.9.1.8 of the Technical Specifications requires prompt reporting with written followup for failures of main steamline Safety/Relief Valves to reclose after actuation.

Subsection 6.9.1.6 of the Technical Specifications requires documentation of all challenges to main steamline Safety/Relief Valves to be included in the Monthly Reactor Operating Report.

18.2.34 PROPORTIONAL INTEGRAL DERIVATIVE CONTROLLER (II.K.3.9)

This requirement is not applicable to Susquehanna SES.

18.2.35 ANTICIPATORY REACTOR TRIP MODIFICATION (II.K.3.10)

This requirement is not applicable to Susquehanna SES.

18.2.36 POWER OPERATED RELIEF VALVE FAILURE RATE (II.K.3.11)

This requirement is not applicable to Susquehanna SES.

18.2.37 ANTICIPATORY REACTOR TRIP ON TURBINE TRIP (II.K.3.12)

This requirement is not applicable to Susquehanna SES.

18.2.38 EMERGENCY PREPAREDNESS-SHORT TERM (III.A.1.1)

18.2.38.1 Statement of Requirement

Comply with Appendix E, "Emergency Facilities," to 10 CFR Part 50, Regulatory Guide 1.101, "Emergency Planning for Nuclear Power Plants," and for the offsite plans, meet essential elements of NUREG-75/111 (Ref. 28) or have a favorable finding from FEMA. This requirement shall be met prior to fuel load.

Provide an emergency response plan in substantial compliance with NUREG-0654, "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants" (which may be modified as a result of public comments solicited in early 1980) except that only a description of and completion schedule for the means for providing prompt notification to the population (App. 3), the staffing for emergencies in addition to that already required (Table B.1), and an upgraded meteorological program (App. 2) need be provided (Ref. 10). NRC will give substantial weight findings on offsite plans in judging the adequacy against NUREG-0654. Perform an emergency response exercise to test the integrated capability and a major portion of the basic elements existing within emergency preparedness plans and organizations. This requirement shall be met before issuance of a full-power license.

18.2.38.2 Interpretation

PP&L is interpreting Emergency Facilities as encompassing those requirements for TSC, Interim TSC, EOF, Interim EOF, SPDS, OSC as outlined in NUREG 0696 and TMI Action Items in 0737. Develop Site, State, County, Township and Municipality Emergency Plans using the Guidelines of NUREG-0654 Rev. 1. Exercise the plans to ensure they are integrated and workable. Comply with meteorological requirements of NUREG 0654 Rev. 1 Appendix 2.

18.2.38.3 Statement of Response

The proposed method of responding to this requirement was submitted by a letter to B. J. Youngblood from N. W. Curtis on April 2, 1981 (PLA-704). Details on the emergency response facilities are presented in the Emergency Plan.

18.2.39 UPGRADE EMERGENCY SUPPORT FACILITIES (III.A.1.2)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.67 for response.

18.2.40 PRIMARY COOLANT SOURCES OUTSIDE CONTAINMENT (III.D.1.1)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.69 for response.

18.2.41 INPLANT RADIATION MONITORING (III.D.3.3)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.70 for response.

18.2.42 CONTROL ROOM HABITABILITY (III.D.3.4)

Requirement superseded by NUREG 0737. Refer to Subsection 18.1.71 for response.

TABLE 18.2-1

TESTING PROGRAM OUTLINE

I. Preoperational/Acceptance Testing.

1. Perform system checkout & operations under the direction of the start-up engineer.

2. ECCS Testing.

3. System Flushing.

4. Procedure "dry run".

II. Cold Functional Testing.*

1. Procedure review/verification performed by operators.

2. Operation of equipment for training under the direction of Shift Supervisor.

III. Hot Functional Testing.

1. Procedure review/verification performed by operators.

2. Operations of equipment for training under the direction of Shift Supervision.

3. Set up of systems for operations at rated conditions under the direction of the Start-up Engineer or Technical Section Engineer.

IV. Start-Up Testing.

1. Performance of the Start-Up Test will be balanced among the shifts so each shift will:

   a. See at least one reactor scram transient.
   b. See at least one pressure regulator transient.
   c. See at least one turbine trip or load rejection transient.
   d. See at least one water level transient.
   e. See at least one recirc flow transient.
   f. Operate the HPCI or RCIC system.

* This testing is not Preoperational Test P 100.

TABLE 18.2-1 (Continued)

2. Conduct preselected start-up tests on the simulator prior to the actual test in the plant.

3. Feedback of data/response to the Nuclear Training Department to update the simulator & materials.

4. Provide each shift with training on testing that they did not perform.

V. Additional Testing

A group of supplemental tests will be developed, to be performed during the Preoperational Test Program, which will provide meaningful technical information in addition to established tests programs. The following procedures will be written or revised to incorporate the supplemental tests as developed by the BWR Owners' Group. The FSAR will be revised as appropriate.

1. TP 2.14 will be revised to incorporate the "integrated Reactor Pressure Vessel Level Instrument Test."

2. P59.2 will be revised to incorporate the "Integrated Containment Pressure Instrumentation Test."

3. New Technical Procedures (TP's) will be written to incorporate three RCIC System Tests.

    a. Start-up of the RCIC system after a loss of alternating current (AC) power to the system.

    b. Operation of the RCIC system with a sustained loss of AC power to the system.

    c. Operation of the RCIC system to verify direct current power separation.